

Application No.:

A.26-05-006

Exhibit No.:

SCE-05

Witnesses:

T. Cameron

E. Salazar

J. Cui

T. Salisbury

L. Dalusong

P. Savani

L. Gaillac

K. Seeto

E. Lee

D. Spencer

R. Liang

A. Wong



SOUTHERN CALIFORNIA
EDISON®

An *EDISON INTERNATIONAL*® Company

(U 338-E)

October Update

Energy Resource Recovery Account (ERRA)

2027 Forecast of Operations

PUBLIC VERSION

Before the

Public Utilities Commission of the State of California

Rosemead, California
October 15, 2026

SCE-05: October Update ERRA Resource Recovery Account (ERRA) 2027 Forecast of Operations

Table of Contents

Section	Page	Witness
I. INTRODUCTION	1	E. Lee
A. 2026 Over-Collection Trigger.....	3	
B. GHG Revenues and the California Climate Credit.....	4	
C. Safety Considerations	5	
II. UPDATED 2027 ERRA FORECAST PROCEEDING REVENUE REQUIREMENT	7	
A. Updated 2027 ERRA Forecast Proceeding Revenue Requirement.....	7	
1. Updated Functionalized ERRA Forecast Proceeding- Related Revenue Requirement.....	10	
a) Generation Service Revenue Requirement	13	
b) Delivery Service Revenue Requirement	13	
2. ERRA BA and PABA Revenue Requirements.....	14	
III. SCE’s BUNDLED SERVICE CUSTOMER ENERGY FORECAST	15	J. Cui
A. SCE Monthly Bundled Energy Forecast.....	15	
B. 2027 Retail Sales and Bundled Forecast Summary	16	
C. Retail Sales Forecast Methodology	17	
D. Historical Trends.....	18	
E. Economic Outlook	20	
F. Weather Assumptions	21	
G. Other Factors Influencing the 2026 Forecast.....	21	
1. Transportation Electrification	22	
2. Behind-the-Meter Solar PV Generation.....	22	
H. Total Retail Sales Forecast by Customer Class	22	

**SCE-05: October Update ERRA Resource Recovery Account
(ERRA) 2027 Forecast of Operations**

Table of Contents (Continued)

Section	Page	Witness
I. Customer Forecast	23	
J. Departing Load Assumption	23	
IV. UPDATED FORECAST ENERGY PRODUCTION AND COSTS FROM SCE'S PORTFOLIO OF RESOURCES	25	T. Salisbury
A. Introduction	25	
B. Energy Production Forecast Methodology	25	
C. Validation of SCE's Energy Production Forecast	27	
D. Updated 2027 Energy and Cost Forecast Summary	28	
E. SCE's Utility-Owned Generation and Purchased Power Contracts	33	
1. Hydro Facilities	33	
2. SCE Solar Photovoltaic Generation	34	
3. CHP and Renewables	35	
a) Energy Forecast	35	
b) Payment Forecast	36	
c) Energy and Capacity Prices	38	
4. Utility-Owned Natural Gas Facilities	40	
a) SCE Peakers	40	
(1) Background and Production	40	
(2) Costs	40	
b) Mountainview Generating Station	40	
5. Inter-utility Contract Production	41	L. Gaillac
a) WAPA-Reclamation Agreement	41	
b) Inter-utility Contract Resource Costs	42	

**SCE-05: October Update ERRA Resource Recovery Account
(ERRA) 2027 Forecast of Operations**

Table of Contents (Continued)

Section	Page	Witness
6. New System Generation CAM Contracts	42	T. Salisbury
a) Production	42	
b) Costs	43	
c) Energy Storage from 2015 GRC	43	
7. System Reliability MCAM Contracts	43	
a) Production	45	
b) Costs	45	
8. Emergency Reliability Procurement (R.20-11-003)	45	
a) Overview	45	
b) Costs	46	
9. Mid-Term Reliability Procurement (D.21-06-035, D.23-02-040, and D.26-02-057)	46	
a) Overview	46	
b) Costs	53	
10. Clean Energy Procurement	55	
a) Overview	55	
b) Production	56	
c) Costs	56	
11. Generic and Bilateral RA Contracts	56	
a) Overview	56	
b) Generic RA Purchase Costs	56	
c) Excess RA Sales Revenue	57	
12. Local Capacity Requirement (LCR) Contracts	57	
a) Production	58	

**SCE-05: October Update ERRA Resource Recovery Account
(ERRA) 2027 Forecast of Operations**

Table of Contents (Continued)

Section	Page	Witness
b) Costs.....	58	
13. Preferred Resource Pilot (PRP)	58	
a) Costs.....	58	
14. Green Tariff Shared Renewables (GTSR) Program	58	
F. Other SCE Resources and Programs.....	61	
1. Nuclear.....	61	T. Cameron
a) Production.....	61	
b) Costs.....	62	
(1) Overview.....	62	
(2) PVNGS Nuclear Fuel Management.....	62	
(3) PVNGS Nuclear Fuel Expense	63	
(a) PVNGS Unit 1	64	
(b) PVNGS Unit 2	64	
(c) PVNGS Unit 3	64	
(4) PVNGS Interim Spent Nuclear Fuel Storage	64	
(5) SONGS Interim Spent Nuclear Fuel Expense	64	
2. Catalina Fuel Costs	66	D. Spencer
3. Demand Response.....	71	A. Wong
G. CAISO Costs, Load Procurement Charges, and Energy Revenue.....	72	T. Salisbury
1. Non-Energy-Related CAISO Costs	73	
2. Load Procurement Charges.....	73	

**SCE-05: October Update ERRA Resource Recovery Account
(ERRA) 2027 Forecast of Operations**

Table of Contents (Continued)

Section	Page	Witness
a) Emergency Reliability Utility-Owned Storage (UOS).....	73	
3. Energy Revenues	74	
H. GHG Costs and Emissions.....	74	
1. 2027 Cap-and-Trade/Invest Costs and Reconciliation of Prior Period GHG Costs	74	
a) Sources of GHG Costs	75	
(1) Direct GHG Costs	75	
(a) Compliance Costs	75	
(b) Procurement Contract Costs	76	
(2) Indirect Costs	76	
(a) QF Contract Costs.....	76	
(b) Market Purchase Costs.....	77	
2. GHG Emissions Volume Forecast Methodology	77	
a) GHG Emissions Associated with Direct Costs.....	77	
(1) GHG Emissions Associated with Compliance Exposure	78	
(2) GHG Emissions Associated with Procurement Contracts.....	79	
b) GHG Emissions Associated with Indirect Costs.....	79	
(1) GHG Emissions Associated with QF Contracts	79	
(2) GHG Emissions Associated with In-State Market Purchases of Electricity	80	
c) Forecast of 2027 GHG Emissions Volumes	81	

**SCE-05: October Update ERRA Resource Recovery Account
(ERRA) 2027 Forecast of Operations**

Table of Contents (Continued)

Section	Page	Witness
3. GHG Emissions Price Forecast Methodology	83	
4. Forecast 2027 GHG Costs	83	
5. Reconciliation of Prior Period GHG Costs.....	85	
I. Hedging Costs.....	87	K. Seeto
1. Transaction Fees	87	
2. Option Premiums	87	
J. Gas Transportation and Storage.....	87	L. Gaillac
1. Transportation.....	87	
a) SoCalGas Transportation Agreement for Mountainview	88	
b) SoCalGas Transportation Agreements for SCE Peakers	88	
c) SoCalGas Transportation Agreements for BTS rights	88	
d) Storage	88	
K. Subscription Fees	88	K. Seeto
L. Allocation of Large Hydro and GHG-Free Nuclear Energy in 2025-2027	89	E. Lee
V. UPDATED FINANCING COSTS	90	P. Savani
A. Commission Decisions Regarding Financing Costs and Collateral Costs.....	90	
B. SCE's Current Short-Term Financings.....	90	
1. Credit Facility	90	
2. Collateral Requirements.....	91	
3. Commercial Paper.....	92	

**SCE-05: October Update ERRA Resource Recovery Account
(ERRA) 2027 Forecast of Operations**

Table of Contents (Continued)

Section	Page	Witness
4. Letters of Credit	92	
C. Other Options Supporting Collateral Requirements	92	
VI. UPDATED CARRYING COSTS.....	93	
A. Updated Fuel Inventory Carrying Costs	93	
B. Updated GHG Compliance Carrying Costs	94	
VII. UPDATED GHG FORECAST REVENUES AND RECONCILIATION.....	96	E. Salazar
A. Overview.....	96	
1. Rulemaking to Improve the California Climate Credit.....	96	
2. Updates to GHG Set-Asides Per Assembly Bill 1207	97	
B. Updated 2027 GHG Allowance Revenue Forecast	98	
1. Amortization and Reconciliation of Prior Period GHG Allowance Revenues.....	99	
C. Updated 2027 Proposed GHG Revenue Return.....	99	L. Dalusong
1. Prior Period Reconciliation and Forecast 2027 SCE Administrative and Customer Outreach Costs.....	100	
a) Reconciliation of Prior Period Administrative and Customer Outreach Costs.....	100	
b) Updated Forecast 2027 SCE Administrative and Customer Outreach Costs.....	100	
2. Clean Energy Programs Set Aside Funding.....	101	E. Salazar
a) Multifamily Affordable Housing Solar Roofs Program (also known as the Solar On Multifamily Affordable Housing (SOMAH) Program)	101	
(1) SOMAH Program Funding True-Up	101	

**SCE-05: October Update ERRA Resource Recovery Account
(ERRA) 2027 Forecast of Operations**

Table of Contents (Continued)

Section	Page	Witness
b) Updated Disadvantaged Communities (DAC) Programs	103	
(1) Cost Recovery for All DAC Programs	103	
(2) Updated SCE's DAC Programs	104	
(3) Updated CCA DAC Programs	105	
3. Transmission Accelerator Revolving Fund	107	
4. Updated Summary of SCE's 2027 Proposed GHG Revenue Returns Eligible Customers and Residential Customers Through the California Climate Credit	108	
5. Updated Historical Allowance Revenue Receipts and Customer Returns	110	
VIII. UPDATED 2027 FORECAST REVENUE REQUIREMENT AND RATEMAKING PROPOSAL	112	E. Lee
A. Introduction	112	
B. Updated Estimated 2027 Forecast Fuel and Purchased Power Revenue Requirement	113	
1. Updated Fuel Expense	115	
2. Updated Forecast Purchased Power Expense	115	
C. Updated Estimated 2027 Forecast Generation Service Revenue Requirement	116	
1. Updated 2027 Forecast Fuel and Purchased Power Costs	117	
a) ERRA BA-Related F&PP Costs	117	
b) PABA-Related F&PP Costs	117	
c) GTSR-Related F&PP Costs	118	
2. Updated Estimated December 31, 2026 Generation- Related Balancing Account Balances	118	

**SCE-05: October Update ERRA Resource Recovery Account
(ERRA) 2027 Forecast of Operations**

Table of Contents (Continued)

Section	Page	Witness
a) ERRA BA	118	
b) PABA	119	
(1) Transfer of the Mohave SO ₂ Allowance Revolving Fund Memorandum Account	120	
c) Estimated Energy Settlement Refunds and Litigation Costs	121	
D. Updated 2027 Forecast Delivery Service Revenue Requirement	122	
1. Forecast New System Generation Net Capacity CAM-Related Costs	123	
a) Introduction	123	
b) 2027 CAM Eligible Costs	125	
2. Updated Estimated December 31, 2026 NSGBA Balance	127	
a) Measure Long Beach Surcharge Balancing Account Advice Letter	128	
3. Updated Estimated System Reliability MCAM- Related Costs	129	
a) Introduction	129	
b) Updated 2027 MCAM Eligible Costs and Estimated December 31, 2026 MCAMBA Balance	130	
4. Updated Estimated Tree Mortality Contract Costs	131	
a) Introduction	131	
b) 2027 Tree Mortality Costs	131	
c) Recovery of BioRAM Audit Expenses in the TMNBCBA	132	

**SCE-05: October Update ERRA Resource Recovery Account
(ERRA) 2027 Forecast of Operations**

Table of Contents (Continued)

Section	Page	Witness
5. Updated Estimated December 31, 2026 TMNBCBA Balance.....	132	
6. Estimated BioMAT Contracts Costs.....	132	
a) Introduction.....	132	
b) Updated 2027 BioMAT Contract Costs.....	133	
c) Updated CCA BioMAT Program	133	
7. Updated Estimated December 31, 2026 BMNBCBA Balance.....	134	
8. Updated Estimated 2027 Spent Nuclear Fuel Revenue Requirement.....	135	
IX. UPDATED 2027 FORECAST COST RESPONSIBILITY SURCHARGES	137	
A. Background.....	138	
B. Updated RA SOD Framework.....	139	
1. Price	140	
2. Quantity.....	141	
a) Baseload Resources	141	
b) Intermittent Resources	141	
c) Stand-alone Storage	142	
d) Hybrid/Co-located Storage	142	
C. Updated Total Portfolio Costs	144	
D. Updated Total Portfolio Market Value	145	
1. Updated Energy Value.....	146	
2. Updated RA Value.....	148	
3. Updated RPS Value	151	

SCE-05: October Update ERRA Resource Recovery Account (ERRA) 2027 Forecast of Operations

Table of Contents (Continued)

Section	Page	Witness
E. Recovery of Balancing and Memorandum Account Balances and UOS Separator Forecast Costs in CTC and PCIA Rates	156	
1. Recovery of the 2026 PABA Balance	156	
2. Transfer of the 2026 Year-End ERRA BA Balance	157	
3. UOS Separator	157	
4. 24-month Amortization of the GRCRRMA	157	
F. Calculation of Final CTC and PCIA Rates	157	
G. Other Proceedings or Filings That May Impact the 2027 CRS	159	
1. Applications for the Sale of Various Hydroelectric Plants	159	
2. 2027 Post-Test Year Advice Letter	160	
3. 2027 Uncollectibles Factor	160	
H. Master Data Request Workpapers and Confidentiality Designations	160	
1. Master Data Request Workpapers	160	
2. Confidentiality Designations	161	
X. UPDATED 2026 COST RESPONSIBILITY SURCHARGE TRUE-UP	162	
A. Overview	162	
B. Background	162	
C. 2026 Market Price Benchmarks	163	
D. 2026 PABA Year-End Balance and Variance Analysis	164	
1. True-Up of Customer Revenues	168	
2. True-Up for Total Portfolio Costs	168	
3. Energy Value True-Up	168	

SCE-05: October Update ERRA Resource Recovery Account (ERRA) 2027 Forecast of Operations

Table of Contents (Continued)

Section	Page	Witness
4. RPS Value True-Up	169	
5. RA Value True-Up.....	171	
6. Forecasted Year-End Transfers in PABA.....	173	
a) Palo Verde Non-Labor Operations and Maintenance Expense Balancing Account.....	173	
b) Continuation of Post-Employment Benefits Other than Pensions Cost Balancing Account, Pension Costs Balancing Account, and Medical Programs Balancing Account	174	
XI. UPDATED PRESENT RATE REVENUES	175	R. Liang
A. Present Rate Revenue	175	
B. Affordability Metrics	176	
C. Updated MCAM Rates	176	
Appendix A Estimated December 31, 2026 Balancing Account Balances		
Appendix B Indifference Rate Calculation		
Appendix C TARF Verifications		

I.

INTRODUCTION

On May 15, 2026, Southern California Edison Company (SCE) filed its Application for Approval of its annual Energy Resource Recovery Account (ERRA) Forecast of Operations (Application) and served supporting testimony (May Testimony). The purpose of this update testimony (the October Update or Update Testimony) is to: (1) update SCE's 2027 ERRA Forecast proceeding revenue requirement, including the load and sales forecast, fuel and purchased power (F&PP) costs, financing costs, and estimated year-end 2026 balances in applicable balancing accounts;¹ (2) update the 2027 Cost Allocation Mechanism (CAM)-related revenue requirement, including the revenue requirement associated with SCE's role as the Local Resource Adequacy (RA) Central Procurement Entity (CPE) for its distribution service area; (3) update the 2027 Cost Responsibility Surcharge (CRS) Indifference Amount; (4) perform a true-up of the 2026 CRS Indifference Amount; and (5) update the 2027 forecast of greenhouse gas (GHG)-related costs and GHG allowance revenue and revenue returns, including the California Climate Credit, to eligible customers.

SCE requests the CPUC authorize SCE's updated 2027 ERRA Forecast proceeding revenue requirement of \$4.510 billion as supported herein.

SCE also proposed to return \$551.460 million in net GHG allowance revenues to eligible customers in 2027 based on the Commission-adopted methodologies and utilizing GHG revenues and Cap-and-Trade costs, including administrative and customer outreach costs as proposed and supported herein. Based on SCE's updated estimates of GHG allowance revenues available for return to eligible customers in 2027, the residential and small commercial customers' semi-annual, on-bill California

¹ Pursuant to Decisions (D.)15-10-037, D.18-12-003, D.18-10-019, and D.25-09-030, SCE is including the following estimated year-end 2026 balancing and memorandum account balances in the 2027 ERRA Forecast revenue requirement: ERRA Balancing Account (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 Modified Cost Allocation Mechanism (MCAM) Balancing Account (MCAMBA).

Climate Credit is forecast to be \$47.00 in 2027 – which is less than the \$54.00 included in the May Testimony for the reasons described herein.

A discussion of SCE’s updated estimated 2027 ERRA Forecast proceeding revenue requirement and proposed rates are presented in Chapter II, and the remaining chapters of this testimony address the following:

- Chapter III: Bundled Service Customer Energy Forecast
- Chapter IV: Updated Forecast Energy Production and Costs from SCE’s Portfolio of Resources²
- Chapter V: Updated Financing Costs
- Chapter VI: Updated Carrying Costs
- Chapter VII: Updated 2027 GHG Forecast Revenues and Reconciliation
- Chapter VIII: Updated 2027 Forecast Revenue Requirement and Ratemaking Proposal
- Chapter IX: Updated 2027 Forecast Cost Responsibility Surcharge Indifference Amount³
- Chapter X: Updated 2026 Cost Responsibility Surcharge True-Up
- Chapter XI: Updated Present Rate Revenues⁴
- Appendix A: Updated Estimated December 31, 2026 Balancing and Memorandum Account Balances
- Appendix B: Updated Indifference Rate Calculation

In accordance with OP 19 of D.22-03-034, SCE’s forecast of its updated Local RA CPE costs, including administrative costs, are included in a separate volume of testimony (Exhibit SCE-06).⁵

² This chapter also includes SCE’s identification of fixed and variable generation costs, as directed in OP 1 of D.25-07-014.

³ This chapter also includes SCE’s ERRA/PABA confidentiality designation framework, as directed in Ordering Paragraph (OP) 7 of D.22-01-023.

⁴ In accordance with D.23-11-094, this chapter includes illustrative MCAM rates.

⁵ OP 19 of D.22-03-034: “CPE procurement costs shall be forecasted and implemented in rates through the annual ERRA forecast proceeding. The CPE procurement costs shall be handled in a separate confidential chapter in ERRA forecast testimony, whereby the confidential contents shall only be viewable to the CPE’s personnel and support personnel, including staff such as contract management, law and regulatory compliance staff. Only CPE transactions that include Local Capacity Requirement Reduction Compensation Mechanism compensation or sale of system Resource Adequacy attributes to the CPE shall be required for inclusion in supporting workpapers or other testimony.”

1 **A. 2026 Over-Collection Trigger**

2 On August 31, 2026, SCE's ERRA Trigger Balance exceeded SCE's ERRA Trigger Point and
3 Threshold (2026 ERRA Trigger) due primarily to lower power and gas prices relative to the forecast
4 used to set the 2026 ERRA Forecast rates, which resulted in an overcollection. While SCE's forecast at
5 the time did reflect a self-correction within 120 days, SCE was also cognizant that the issuance of the
6 Final 2026 MPBs could result in significant changes to that forecast. Thus, because SCE could not
7 reasonably determine that the ERRA Trigger Balance would self-correct within 120 days,⁶ on
8 September 30, 2026, SCE filed A.26-09-019.

9 SCE's ERRA Trigger Balance is expected to fall below the Trigger Point and Threshold with the
10 implementation of the rates in this instant proceeding. This is because the final 2026 year-end balances
11 that comprise the ERRA Trigger Balance are put into rates as part of the implementation of this ERRA
12 Forecast Application. SCE currently anticipates implementing the 2027 ERRA Forecast rates on
13 January 1, 2027,⁷ which would be 123 days from the date of the 2026 ERRA Trigger.

14 Therefore, in A.26-09-019, SCE requested that the Commission (1) find that SCE complied with
15 applicable ERRA Trigger requirements,⁸ (2) consolidate A.26-09-019 with A.26-05-006, (3) allow SCE
16 to maintain its ERRA-related rates at their current level for 2026, (4) grant SCE's proposal to address
17 the ERRA Trigger Balance in the 2027 ERRA Forecast with the implementation of the 2027 ERRA
18 Forecast rates, and (5) grant any other relief the Commission deems appropriate.⁹

19 On October 1, 2026, the Commission's Energy Division issued the latest MPBs. On October 2,
20 2026, the Commission issued the *Assigned Commissioner's Ruling on Expedited Schedule Notice of*
21 *Prehearing Conference and Preliminary Categorization* in A.26-09-019, which scheduled a Prehearing
22 Conference (PHC) on October 19, 2026. On October 5, 2026, Administrative Law Judge (ALJ)

⁶ Self-correction is defined as an ERRA Trigger Balance that is below the five percent Threshold amount. *See* D.19-12-001, p. 31.

⁷ *See* A.26-05-006 Scoping Memo.

⁸ *See* D.02-10-062, D.04-12-048, D.06-06-051, D.19-12-001, and D.22-01-023.

⁹ A.26-09-019, SCE-01, pp. 1-2.

1 Brandon Gerstle issued an Email Ruling in this instant proceeding taking notice of A.26-05-006
2 ordering that SCE incorporate all analysis related to D.26-09-019 in this October Update and for parties
3 to address any matters from A.26-09-019 in the comments and/or briefs for this proceeding.¹⁰

4 Using the final balances recorded in September 2026 for the ERRA BA and the PABA, which
5 include the impact of the true-up of the 2026 MPBs, results in an ERRA Trigger Balance of -9.34
6 percent, representing an overcollection of \$427.591 million. Based on SCE's updated 2026 year-end
7 forecast for the ERRA BA and PABA,¹¹ shown in Appendix A, a self-correction to the ERRA Trigger
8 Balance is no longer expected before the end of the year. As SCE described in its ERRA Trigger
9 testimony,¹² a decrease to the MPBs exacerbated the overcollection ERRA Trigger because the lower
10 MPBs resulted in (1) an increased undercollection in the PABA, which is borne by both bundled service
11 and departing load customers, and (2) an increased overcollection in the ERRA BA, which is credited
12 solely to bundled service customers.

13 SCE maintains that consolidation of A.26-09-019 into this instant proceeding and the expected
14 rate change on January 1, 2027, for the 2027 ERRA Forecast rates would resolve the ERRA Trigger.

15 **B. GHG Revenues and the California Climate Credit**

16 As directed by the Commission's *Phase 2 Decision Adopting Standard Procedures for Electric*
17 *Utilities to File Greenhouse Gas (GHG) Forecast Revenue and Reconciliation (FR&R) Requests* (D.14-
18 10-033), issued in A.13-08-002 *et al.*, dated October 16, 2014, the investor-owned utilities (IOUs) are to
19 include their GHG revenue and reconciliation requests as an additional chapter or section within the
20 ERRA Forecast applications.¹³ SCE's Application proposes to return a total of \$551.460 million in net
21 GHG allowance revenues to eligible customers in 2027 based on the Commission-adopted
22 methodologies and utilizing GHG revenues and cap-and-invest costs, including administrative and

¹⁰ ALJ Gerstle's Email Ruling Addressing Trigger Application (issued October 5, 2026).

¹¹ SCE uses recorded amounts through September 2026, which include the true-up of Actual Retained RA and Actual Retained RPS for January through September using the Final 2026 MPBs, and a forecast for October through December 2026.

¹² A.26-09-019, SCE-01, p. 13: 1-5.

¹³ D.14-10-033, OP 10.

customer outreach costs, as proposed and supported herein. Based on SCE's estimated GHG allowance revenues available for return to eligible customers in 2027, residential and small commercial customers can expect a semi-annual, on-bill California Climate Credit of \$47.00 in 2027.

C. Safety Considerations

D.16-01-017 approved an amendment to Rule 2.1(c) of the Commission's Rules of Practice and Procedure (Title 20, Division 1, of the California Code of Regulations) to require all applications to identify all relevant safety considerations implicated by the application. One of SCE's core values is to ensure public and employee safety. As such, the procurement of F&PP (whether for SCE-owned units, contracted through Power Purchase Agreements (PPAs), or purchased through the California Independent System Operator (CAISO) or other power exchanges), inherently assumes that all power providers are fully compliant with laws, rules, regulations, and internally-managed controls to help ensure that their generating facilities are operated and maintained in a safe working condition. Likewise, SCE's management of air emissions costs (*e.g.*, GHG cap-and-trade costs and other similar costs), and transmission capacity procurement activities, also assume the counterparties to these transactions are fully compliant with laws, rules, regulations, and internally managed controls to help ensure that their facilities are operated and maintained in a safe working condition.

The safety performance of the counterparties involved (once contracted) is not directly related to SCE's activities at issue in this proceeding, which include the forecast for sales and purchases of power, fuel, transmission capacity, and air emissions credits and allowances. Nevertheless, these activities do support public and worker safety, as these transactions are an inherent part of ensuring a reliable supply of electricity to SCE customers. Costs incurred by SCE to operate and maintain SCE's office and public spaces, shops, warehouses, transmission and distribution facilities, and utility-owned power plants in a safe condition are reviewed in SCE's General Rate Case (GRC) applications.

In addition, in accordance with D.18-12-014, and subsequent Commission decisions issued in R.20-07-013, including D.21-11-009, D.22-12-027, D.24-05-064, and D.25-08-032, SCE filed its second Risk Assessment Mitigation Phase (RAMP) on May 15, 2026. The RAMP report provides Commission staff and other parties with the opportunity to analyze and understand the various models and

1 methodologies that SCE uses to analyze top safety risks, explains how SCE analyzes and priorities each
2 safety risk, and evaluates mitigation activities and estimated costs for each risk, including realistic
3 alternatives to the proposed mitigation plans. SCE's 2029 GRC application will integrate elements from
4 the 2025 RAMP.

1 II.

2 **UPDATED 2027 ERRRA FORECAST PROCEEDING REVENUE REQUIREMENT**

3 A. **Updated 2027 ERRRA Forecast Proceeding Revenue Requirement**

4 SCE requests that the Commission authorize an updated 2027 ERRRA Forecast proceeding
5 revenue requirement of \$4.510 billion beginning January 1, 2027, based on updated forecast costs and
6 assumptions. This updated 2027 ERRRA Forecast proceeding revenue requirement is an increase of
7 \$159.856 million from the estimated revenue requirement presented in the May Testimony, and a
8 decrease of \$200.798 million from the ERRRA Forecast-related revenue requirement currently reflected
9 in customers' 2026 ERRRA Forecast-related rates.¹⁴

10 As shown in Table II-1, this Update Testimony includes the following changes to SCE's 2027
11 F&PP forecast (compared to SCE's May Testimony):

- 12 • Based on an August 24, 2026 trade date, SCE is forecasting one percent lower SP-15
13 power prices and a half percent higher gas prices compared to the May Testimony. This
14 shift in market fundamentals reduced the 2027 implied market heat rate (IMHR) by
15 approximately four percent, appropriately lowering forecast generation from SCE's
16 dispatchable gas portfolio. (*decreases load procurement costs, CAM market revenues,*
17 *gas dispatchable energy costs and PABA market revenues*).
- 18 • The addition of new contracts delivering in 2027 that were executed after the May Filing,
19 removal of terminated resources, and changes in commercial online dates (COD) for
20 executed but not yet online projects (*overall nets to an increase in contracted capacity*
21 *costs*);
- 22 • [REDACTED] resulting from updates to the resource adequacy
23 (RA) position due to incorporating final 2027 requirements and allocations and
24 incorporation of recent RA rule changes for co-located charging sufficiency projects,

¹⁴ The rates in effect today are based on the revenue requirement approved in D.25-12-028, the final decision in SCE's 2026 ERRRA Forecast proceeding.

resulting in changes to generic RA procurement and sales (*lower RA purchases cost, higher revenues from RA sales*);

- Significantly lower revenues from Voluntary Allocation sales as a result of the application of the 2027 Forecast RPS Adder (80 percent decrease from the May Forecast RPS Adder) and a slightly lower bundled share of eligible resources driven by lower 2027 load shares (*decrease in REC sales revenue*); and
- Updated forecast outage information, resource characteristics, and operating costs used in SCE's PLEXOS model for its gas-fired portfolio, resulting in decreased forecasted volumes of generation from SCE's PABA portfolio (*decreases PABA and CAM market revenues, lowers UOG and CAM fuel costs*).

Table II-1
Updated Estimated 2027 ERRA Forecast Revenue Requirement Changes Compared to May Testimony
(\$000)

Line No. (a)	Description (b)	October Update (c)	May Testimony (d)	Rev Req Change (e) = (c) - (d)
1.	2027 Forecast Fuel and Purchased Power ^{2/}	\$ 4,901,530	\$ 4,701,725	\$ 199,806
2.	2026 YE ERRA Balancing Account	\$ (1,288,988)	\$ (330,813)	\$ (958,176)
3.	2026 YE Energy Settlements Memorandum Account (ESMA) - Net Amount	\$ 144	\$ 70	\$ 74
4.	2026 YE Portfolio Allocation Balancing Account (PABA) ^{3/}	\$ 1,438,745	\$ 557,872	\$ 880,873
5.	2026 YE New System Generation Balancing Account (NSGBA)	\$ 9,669	\$ 29,935	\$ (20,266)
6.	2026 YE Modified Cost Allocation Mechanism Balancing Account (MCAMBA)	\$ 967	\$ 1,145	\$ (179)
7.	2026 YE Tree Mortality Non-Bypassable Charge Balance Account (TMNBCBA)	\$ 2,607	\$ 8,476	\$ (5,869)
8.	2026 YE BioMAT Non-Bypassable Charge Balance Account (BMNBCBA)	\$ (2,927)	\$ (1,297)	\$ (1,630)
9.	GHG Allowance Revenues	\$ (551,460)	\$ (616,682)	\$ 65,223
10.	TOTAL ERRA PROCEEDING REVENUE REQUIREMENT	\$ 4,510,287	\$ 4,350,431	\$ 159,856

^{1/} Per D.25-12-028, the 2026 ERRA Forecast revenue requirement was implemented into rates on January 1, 2026 (Advice 5717-E).

^{2/} Includes spent nuclear fuel.

^{3/} Excludes the revenue requirement associated with the 2025 General Rate Case Revenue Requirement Memorandum Account (GRCRRMA).

As compared to the May Testimony, the changes in the forecast of the 2026 year-end balances in the ERRA BA and the PABA are largely driven by the decreases in the 2026 Final RA and RPS Adders released by the Commission's Energy Division on October 1, 2026.

1 SCE's 2027 F&PP costs forecast is projected to be higher than SCE's 2026 ERRRA forecast—
2 based on both increases and decreases in various cost categories that overall net to an increase of five
3 percent. Some of these factors, such as the revenues associated with the market price benchmark,
4 termination of contracts in 2026, are mentioned above. Other notable drivers for the year-over-year
5 increase in the F&PP cost forecast are:

- 6 • SCE's net bundled service customer load forecast is approximately one and a half percent
7 lower than in 2026 (*decreases load procurement costs*);
- 8 • Lower forecasted revenues due to 11% lower SP-15 prices when compared to the 2026
9 October updates coupled with overall 62% lower dispatch from gas dispatchable resources
10 (*decreases CAM and PABA market revenues, CAM and UOG fuel and energy costs, lower*
11 *GHG costs*); and,
- 12 • Addition of new RA and C&R purchases, including contracts related to mid-term reliability
13 (MTR) procurement, SCE's Clean Energy solicitation, and ReMAT projects, coming online
14 in 2027 (including eight solar, one geothermal, and five energy storage contracts) (*increases*
15 *costs and PABA market revenues*).

16 As shown in Table II-2 below, the updated 2027 ERRRA Forecast revenue requirement of \$4.510
17 billion represents a decrease of \$200.798 million compared to the ERRRA Forecast-related revenue
18 requirement used to set rates in effect today.¹⁵

¹⁵ Per D.25-12-028, the 2026 ERRRA Forecast revenue requirement was implemented into rates on January 1, 2026 (Advice 5717-E).

Table II-2
Updated Estimated 2027 ERRA Forecast Revenue Requirement Changes
Compared to Current Rates

Line No.	Description	Estimated 2027 Revenue Requirement	In Rates ^{1/}	Rev Req Change
(a)	(b)	(c)	(d)	(e) = (c) - (d)
1.	2027 Forecast Fuel and Purchased Power ^{2/}	\$ 4,901,530	\$ 4,727,383	\$ 174,147
2.	2026 YE ERRA Balancing Account	\$ (1,288,988)	\$ (786,104)	\$ (502,884)
3.	2026 YE Energy Settlements Memorandum Account (ESMA) - Net Amount	\$ 144	\$ 1,392	\$ (1,249)
4.	2026 YE Portfolio Allocation Balancing Account (PABA) ^{3/}	\$ 1,438,745	\$ 1,224,521	\$ 214,225
5.	2026 YE New System Generation Balancing Account (NSGBA)	\$ 9,669	\$ (25,816)	\$ 35,485
6.	2026 YE Modified Cost Allocation Mechanism Balancing Account (MCAMBA)	\$ 967	\$ 2,992	\$ (2,025)
7.	2026 YE Tree Mortality Non-Bypassable Charge Balance Account (TMNBCBA)	\$ 2,607	\$ 14,434	\$ (11,827)
8.	2026 YE BioMAT Non-Bypassable Charge Balance Account (BMNBCBA)	\$ (2,927)	\$ (4,438)	\$ 1,511
9.	GHG Allowance Revenues	\$ (551,460)	\$ (443,279)	\$ (108,181)
10.	TOTAL ERRA PROCEEDING REVENUE REQUIREMENT	\$ 4,510,287	\$ 4,711,084	\$ (200,798)

^{1/} Per D.25-12-028, the 2026 ERRA Forecast revenue requirement was implemented into rates on January 1, 2026 (Advice 5717-E).

^{2/} Includes spent nuclear fuel.

^{3/} Excludes the revenue requirement associated with the 2025 General Rate Case Revenue Requirement Memorandum Account (GRCRRMA).

1. Updated Functionalized ERRA Forecast Proceeding-Related Revenue Requirement

SCE's ERRA Forecast proceeding revenue requirement includes the 2027 F&PP and GHG costs and revenues of SCE's portfolio of resources, and the 2026 year-end balances in various balancing and memorandum accounts, as outlined below. The revenue requirement is functionalized between "generation service" and "delivery service."

The generation service revenue requirement recovers the 2027 forecast F&PP and GHG costs of resources that are recorded to the ERRA BA, the PABA, and the Green Tariff Shared Renewables Balancing Account (GTSRBA); and the 2026 year-end balances in the ERRA BA and the PABA. The amounts recorded in the ERRA BA and the GTSRBA are recovered from SCE's bundled service customers, while amounts recorded in the PABA are recovered on a "vintaged" basis from bundled service customers and Departing Load customers.¹⁶

¹⁶ Departing Load customers include DA, Community Aggregation (CA), and CCA customers.

1 The delivery service revenue requirement recovers the 2027 forecast F&PP and GHG
2 costs of resources that are recorded to the NSGBA,¹⁷ the Public Purpose Programs subaccount of the
3 Local Capacity Requirements Products Balancing Account (LCRPBA),¹⁸ the TMNBCBA, the
4 BMNBCBA, the MCAMBA, the Distribution subaccount of the Base Revenue Requirement Balancing
5 Account (BRRBA-D), as well as the resources procured to meet system reliability procurement pursuant
6 to D.19-11-016 (which record to the MCAMBA, NSGBA, and PABA);¹⁹ GHG allowance revenues; and
7 the 2026 year-end balances in the NSGBA, TMNBCBA, BMNBCBA, and MCAMBA. The delivery
8 service revenue requirement is recovered from all customers to whom SCE delivers electricity (*i.e.*,
9 bundled service and Departing Load customers), except for the revenue requirement related to the
10 system reliability procurement pursuant to D.19-11-016.²⁰

11 As shown on Line No. 32 in Table II-3, SCE forecasts a decrease of approximately
12 \$200.798 million in its 2027 ERRA Forecast proceeding revenue requirement from the revenue
13 requirement used to set rates in effect today. This sum includes an increase of \$3.532 million in the
14 generation service requirement from the rates in effect today, as shown on Line No. 9 of Table II-3; and
15 a decrease of \$204.329 million in the delivery service revenue requirement from the rates in effect
16 today, as shown on Line No. 31 of Table II-3. The discussion below compares the 2027 ERRA Forecast
17 proceeding revenue requirement with the authorized 2026 ERRA forecast revenue requirement by
18 function.

¹⁷ The forecast of 2027 contract and administrative net costs that SCE will incur to function as the CPE for procuring local RA in its service area pursuant to D.20-06-002 are supported in Exhibit SCE-06.

¹⁸ Resources recorded in the LCRPBA also transfer to the NSGBA and BRRBA-D.

¹⁹ Prior to the establishment of the MCAMBA, these costs were recorded in the System Reliability Procurement Memorandum Account (SRPMA).

²⁰ The revenue requirement associated with system reliability procurement pursuant to D.19-11-016 is only recovered from bundled service customers (via the 2019 subaccount of the PABA) and customers of other LSEs who opted out of their own system reliability procurement pursuant to D.19-11-016 via MCAM or NSG rates (under certain circumstances such as an LSE bankruptcy).

Table II-3
Updated 2027 ERRA Forecast Proceeding Revenue Requirement Changes
(\$000)

Line No. (a)	Description (b)	Estimated 2027 Revenue Requirement (c)	In Rates (d)	Rev. Req. Change (e) = (c) - (d)
1.	<u>Generation Service</u>			
2.	2027 Fuel and Purchased Power (includes GHG costs)			
3.	ERRA BA-related	\$ 2,322,147	\$ 2,712,535	\$ (390,388)
4.	PABA-related	\$ 2,182,038	\$ 1,495,606	\$ 686,432
5.	GTSR-related	\$ 4,710	\$ 7,315	\$ (2,604)
6.	2026 YE ERRA BA Balance	\$ (1,288,988)	\$ (786,104)	\$ (502,884)
7.	2026 YE PABA Balance ^{3/}	\$ 1,438,745	\$ 1,224,521	\$ 214,225
8.	2026 YE ESMA Balance (net)	\$ 144	\$ 1,392	\$ (1,249)
9.	TOTAL ERRA PROCEEDING GENERATION SERVICE	\$ 4,658,796	\$ 4,655,264	\$ 3,532
10.	<u>Delivery Service</u>			
11.	New System Generation Rate Component:			
12.	2027 NSG Fuel and Purchased Power (includes GHG costs)	\$ 352,716	\$ 473,469	\$ (120,753)
13.	2026 YE NSGBA Balance	\$ 9,669	\$ (25,816)	\$ 35,485
14.	Total New System Generation	\$ 362,385	\$ 447,652	\$ (85,268)
15.	MCAM Rate Component:			
16.	2027 MCAM Fuel and Purchased Power	\$ 3,797	\$ 3,685	\$ 112
17.	2026 YE MCAMBA Balance	\$ 967	\$ 2,992	\$ (2,025)
18.	Total MCAM	\$ 4,764	\$ 6,677	\$ (1,913)
19.	Nuclear Decommissioning Rate Component:			
20.	2027 Spent Nuclear Fuel	\$ 5,433	\$ 5,337	\$ 96
21.	Total Nuclear Decommissioning	\$ 5,433	\$ 5,337	\$ 96
22.	Distribution Rate Component:			
23.	2027 BRRBA-D Fuel and Purchased Power	\$ (2,459)	\$ (2,686)	\$ 227
24.	GHG Allowance Revenues	\$ (551,460)	\$ (443,279)	\$ (108,181)
25.	Total Distribution	\$ (553,919)	\$ (445,965)	\$ (107,954)
26.	Public Purpose Programs Charge (PPPC):			
27.	2027 PPPC Fuel and Purchased Power ^{2/}	\$ 33,148	\$ 32,123	\$ 1,025
28.	2026 YE TMNBCBA Balance	\$ 2,607	\$ 14,434	\$ (11,827)
29.	2026 YE BMNBCBA Balance	\$ (2,927)	\$ (4,438)	\$ 1,511
30.	Total Public Purpose Programs Charge	\$ 32,828	\$ 42,119	\$ (9,291)
31.	TOTAL ERRA PROCEEDING DELIVERY SERVICE	\$ (148,509)	\$ 55,820	\$ (204,329)
32.	TOTAL ERRA PROCEEDING REVENUE REQUIREMENT	\$ 4,510,287	\$ 4,711,084	\$ (200,798)

^{1/} Per D.25-12-028, the 2026 ERRA Forecast revenue requirement was implemented into rates on January 1, 2026 (Advice 5717-E).

^{2/} Includes TMNBC, BMNBC, LCR-PPP and DAC-GT/CSGT PPPC amounts.

^{3/} Excludes the revenue requirement associated with the 2025 General Rate Case Revenue Requirement Memorandum Account (GRCRRMA).

1 a) Generation Service Revenue Requirement

2 As described above, SCE's generation-function F&PP and GHG costs will be
3 recorded to the ERRA BA, the PABA and the GTSRBA. As shown on Line No. 9 in Table II-3 above,
4 the increase of \$3.532 million in SCE's 2027 ERRA Forecast generation service revenue requirement
5 (as compared to the revenue requirement reflected in current rates) is due to the following factors: (i) a
6 decrease of \$390.388 million in the ERRA BA-related F&PP cost forecast and a decrease of \$502.884
7 million in the estimated 2026 year-end ERRA BA as shown on Line Nos. 3 and 6, respectively; (ii) an
8 increase of \$686.432 million in the PABA-related F&PP cost forecast and an increase of \$214.225
9 million in the estimated 2026 year-end PABA, as shown on Line Nos. 4 and 7, respectively; (iii) a
10 decrease of \$2.604 million in the GTSR-related F&PP cost forecast as shown on Line No. 5; and (iv) a
11 decrease of \$1.249 million associated with net generator refunds related to the 2000-2001 California
12 Energy Crisis settlements approved by the Federal Energy Regulatory Commission (FERC) as shown on
13 Line No. 8.

14 b) Delivery Service Revenue Requirement

15 As shown on Line No. 31 in Table II-3 above, the decrease of \$204.329 million in
16 SCE's 2027 ERRA Forecast delivery service revenue requirement (as compared to the revenue
17 requirement reflected in current rates) is due to the following factors: (i) a decrease in the New System
18 Generation (*i.e.*, CAM-related) forecast revenue requirement of \$120.753 million as shown on Line No.
19 12 and an increase of \$35.485 million associated with the estimated 2026 year-end balance in the
20 NSGBA as shown on Line No. 13; (ii) an increase of \$0.112 million for the MCAM-related System
21 Reliability forecast procurement pursuant to D.19-11-016 as shown on Line No. 16 and a decrease of
22 \$2.025 million associated with the estimated 2026 year-end balance in the MCAMBA as show on Line
23 No. 17; (iii) an increase of \$0.096 million associated with spent nuclear fuel costs as shown on Line No.
24 20; (iv) a net decrease of \$107.954 million associated with Distribution rate recovery as shown on Line
25 No. 25; and (v) a net decrease of \$9.291 million associated with the Public Purpose Programs Charge
26 (PPPC) rate recovery as shown on Line No. 30.

1 **2. ERRA BA and PABA Revenue Requirements**

2 The ERRA BA and PABA F&PP sub-totals above reflect the total 2027 forecast F&PP
3 costs of resources that will record to each account. However, pursuant to D.18-10-019, D.19-10-001,
4 and Preliminary Statement Parts WW and ZZ, the ERRA BA will also record the actual retained RPS
5 and RA value of the PCIA-eligible RECs and RA as a debit, while the PABA will record a
6 corresponding credit, as applicable.²¹ Additionally, the PABA will record the base revenue requirement
7 associated with SCE's Utility Owned Generation (UOG), which is determined in Phase 1 of SCE's
8 GRC.²²

²¹ Refer to Chapter IX for a discussion of how amounts are recorded associated with banked RECs.

²² Because Phase 1 of SCE's 2025 GRC (A.23-05-010) was approved in D.25-09-030, this Update Testimony incorporates the 2026 Authorized Generation Base Revenue Requirement (AGBRR) adopted in D.25-09-030. The AGBRR will be updated for 2027 in the implementation advice letter.

III.

SCE's BUNDLED SERVICE CUSTOMER ENERGY FORECAST

This chapter presents a summary of SCE's 2027 forecast of bundled service customer energy load in SCE's service area and a brief description of the methodology used to produce the forecast. A discussion of the major factors and assumptions that influence the forecast is also presented, including the meet-and-confer activities conducted with CCAs in accordance with D.20-03-019.²³ This forecast has not changed from what SCE presented in its May filing.

A. SCE Monthly Bundled Energy Forecast

SCE forecasts annual bundled load of [REDACTED] GWh for 2026 and [REDACTED] GWh for 2027, [REDACTED] compared to 2025 actual recorded load of 53,592 GWh. Bundled service customer energy at the CAISO delivery point is derived by adjusting the bundled service customer sales forecast to account for losses between the CAISO interface and customer meters (i.e., distribution losses).²⁴ Hourly bundled service customer loads are determined by applying an hourly load shape to the annual bundled energy forecast. Load shapes are created using econometric methods that relate each hour's historical load to daily geographically weighted temperature, calendar variables (e.g., day of the week, month, holidays), and various time trend variables. Forecast monthly bundled energy is then derived by summing the forecast hourly load for each calendar month. Forecast monthly bundled service customer peak demand is determined by selecting the maximum hourly load in each calendar month. Table III-4 presents recorded bundled service customer monthly energy at CAISO in 2025 and the forecast of monthly bundled service customer energy at the CAISO interface point in 2026 and 2027

²³ OP 1 of D.20-03-019 requires that SCE "report their meet-and confer activities and information exchange with Community Choice Aggregators in their service territories in their respective ERRA Forecast application via testimony and in their respective initial annual Resource Adequacy load forecasting filing via verification." A list of the CCAs that SCE engaged in meet-and-confers with in preparation for this filing is included in testimony below.

²⁴ Specifically, SCE applies a historical average loss factor to retail sales in the following way: Annual Bundled Energy @ CAISO = Annual Bundled Sales * DLF, where DLF is the ratio of CAISO settlement quality meter data and bundled sales at the customer meter averaged over the years.

(the first two months of 2026 are actual recorded bundled load). The amounts shown have been adjusted to reflect exports via the Net Energy Metering (NEM) tariff.

Table III-4
Bundled Energy at CAISO (NEM Adjusted)²⁵

Line No.	Month	2025	2026*	2027*
1.	January	4,214	4,067	
2.	February	3,662	3,732	
3.	March	3,891		
4.	April	3,690		
5.	May	4,229		
6.	June	4,717		
7.	July	5,243		
8.	August	6,032		
9.	September	5,413		
10.	October	4,322		
11.	November	3,995		
12.	December	4,183		
13.	Total	53,592		

Actual and Forecast nets out NEM exports.

*Areas shaded in gray are confidential per D.06-06-066, Matrix section V.C.

B. 2027 Retail Sales and Bundled Forecast Summary

SCE developed its bundled service customer energy forecast for this Application based on a retail customer sales forecast completed in January 2026. The retail sales forecast consists of forecast sales to bundled service and Departing Load customers measured at the customer meter. Total retail net electricity sales in SCE's service area totaled 78,458 gigawatt hours (GWh) in 2025. For 2026 and 2027, SCE is forecasting sales of 78,132 GWh and 79,944 GWh, respectively. The small increase in 2027 is mainly due to increased electricity consumption from increased space cooling and additional transportation electrification load.

As referenced above, SCE derives its bundled customer energy forecast from the retail sales forecast. Table III-5 summarizes the steps in converting retail sales to bundled service customer energy

²⁵ Bundled loads shown are net loads that are NEM-export adjusted, as measured at CAISO interface.

at the CAISO interface. Retail sales consist of two components: (1) bundled service customer sales and (2) Departing Load customer sales. Subtracting the forecast of Departing Load customer sales from total retail sales yields a forecast of bundled service customer sales. For 2027, the retail net sales forecast is 79,944 GWh less [REDACTED] sales to DA customers and [REDACTED] sales to customers supplied by CCAs sales, which yields a bundled sales forecast of [REDACTED]²⁶ Those forecasts have been adjusted to account for NEM energy exports, which reduce the energy measured at the CAISO interface.

Table III-5
Annual Retail Sales by Customer Class
(GWh)

Line No.	Description	2025	2026*	2027*
1.	Total Retail Sales (@meter)	78,458	78,132	79,944
2.	Direct Access Sales (@meter)	11,931		
3.	CCA Sales (@meter)	16,001		
4.	Bundled Service Sales (@meter)	50,526		
5.	Bundled Energy at ISO	53,592		

Actual and Forecast nets out NEM exports.

*Areas shaded in gray are confidential per D.06-06-066, Matrix section V.C.

C. Retail Sales Forecast Methodology

SCE uses econometric models to forecast monthly retail electricity sales (recorded sales as billed, measured at the customer meter) by customer class. Retail sales include final sales to bundled service customers and Departing Load customers within SCE's service area. Retail sales exclude sales to public power customers, contractual sales, and interchanges with other utilities.

The retail sales forecast represents the sum of sales in seven customer classes: (1) residential; (2) small commercial; (3) medium commercial; (4) large commercial and industrial; (5) agricultural and pumping; (6) street lighting and traffic control; and (7) inter-department transfers (IDT). SCE continues to classify residential customers geographically but has updated the manner in which it classifies non-residential retail electricity sales customers for purposes of reporting and forecasting in this proceeding.

²⁶ To calculate Bundled Customer load at the CAISO interface, the bundled service customer sales forecast is scaled up to account for distribution losses.

1 The updated classification framework improves alignment between customer groupings and the rate
2 structures under which customers take service, thereby enhancing analytical consistency and the
3 accuracy of retail sales forecasts used in the ERRRA Forecast. Each customer class forecast (except IDT)
4 is itself the product of two separate forecasts: (1) a forecast of electricity consumption per customer and
5 (2) a forecast of the number of customers. The IDT forecast, which represents a very small percentage
6 of total retail sales, is based upon the average of recorded monthly sales over the most recent 12-month
7 period.

8 SCE employs econometric models to quantify the historical relationship between electricity
9 consumption and the various economic, demographic, and other factors that theoretically influence
10 measured electricity consumption. Examples of such variables are weather, number of billing days,
11 employment, and personal income indices. The typical estimation procedure used to construct the
12 models is ordinary least squares (OLS). Additional documentation of the statistical model
13 specifications, including equation forms, variable definitions, and estimation results, is provided in
14 SCE's Chapter III workpapers. SCE aggregates the model outputs to develop annual forecast results
15 including an annual residential versus non-residential sector summary. SCE then applies a series of
16 post-model adjustments to reflect drivers that are not fully captured in the historical regression
17 relationships or that are best represented as explicit "load modifiers." These adjustments include
18 end-use electrification impacts such as transportation electrification and building electrification and
19 incremental load from emerging customer segments (e.g., cultivation and data centers), and other
20 forecast refinements based on the most current information available at the time of the forecast. In
21 addition, SCE incorporates distributed energy resource (DER) impacts that affect net retail sales,
22 including distributed generation (such as behind-the-meter solar PV, wind, and CHP), energy efficiency
23 impacts, and the effects of energy storage as applicable. Together, these model outputs and post-model
24 adjustments produce the final retail sales forecast.

25 **D. Historical Trends**

26 SCE's total electricity sales were relatively flat between 2019 and 2021. In 2022, SCE saw
27 increased sales due to stronger and sooner-than-expected economic recovery as the state emerged from

the pandemic and increased sales due to hot summer weather. Sales in 2023 were lower than 2022 due to a return to mild summer weather. The increase in 2024 sales was driven by relatively higher summer temperatures compared with 2023. In contrast, milder weather in 2025 led to sales levels comparable to 2023. Customer-count growth has averaged 0.6 percent annually between 2021 and 2025. Population trends in SCE’s service area are expected to be relatively stable, while household formation—particularly in the Inland Empire—is anticipated to support ongoing customer growth.

***Figure III-1
Total Gross Metro Product in the Counties Served by SCE
2015 to 2025***

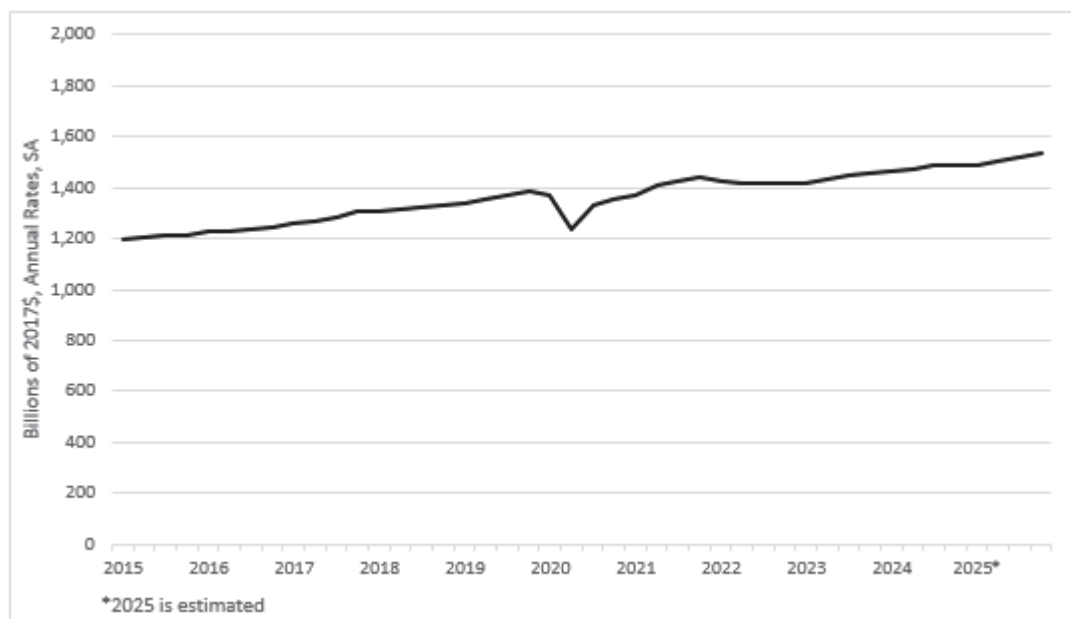
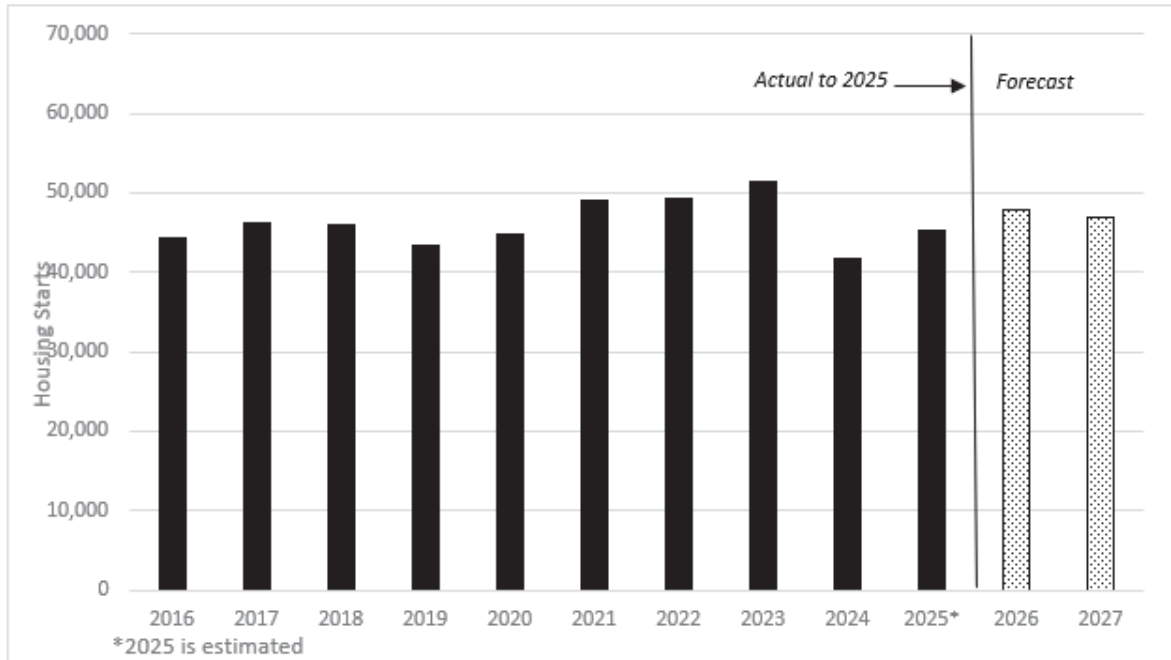


Figure III-2
Residential Housing Starts in Counties Served by SCE



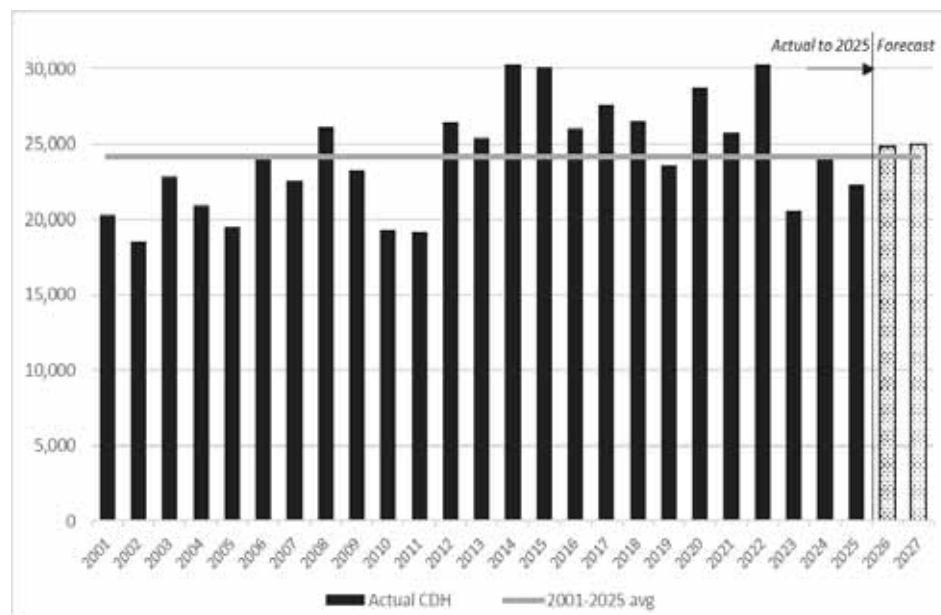
E. Economic Outlook

SCE established its macroeconomic outlook for this sales forecast cycle by referencing the September 2025 forecasts from Moody's Analytics and S&P Global Market Intelligence, the latest information available at the time the forecast was made. Regional economic activity, as measured by real gross metro product, reflects continued moderate growth, with rates of 2.7 percent in 2024 and an estimated 2.3 percent in 2025, before moderating to about 2 percent annually across SCE's service area. Housing starts are expected to recover from the recent low in 2024, which was mainly attributed to high inflation and interest rates, and to continue growing modestly in the coming years, as displayed in Figure III-2 above. The average residential housing construction forecast is expected to peak in 2026, after which housing starts are expected to slow, consistent with Moody's Analytics and S&P Global Market Intelligence population outlooks that project population declines beginning in 2027.

F. Weather Assumptions

SCE uses estimated monthly heating degree hours (HDHs)²⁷ and cooling degree hours (CDHs)²⁸ as inputs to its energy forecast (through consumption/usage forecast models). As shown in Figure III-3 below, SCE's service area experienced more CDHs in the past 10 years, which reflects the impact of climate change. SCE's forecasted temperatures reflect this warming trend.

Figure III-3
Recorded and Forecast Cooling Degree Hours



G. Other Factors Influencing the 2026 Forecast

Other major factors impacting the total retail sales forecast include transportation electrification (including both light-duty and non-light-duty electric vehicle charging load) and behind-the-meter solar photovoltaic generation (such as residential rooftop solar and combined heat and power installations).

²⁷ Heating degree hours are the summation of hourly temperatures deviated from the threshold temperature of 65°F.

²⁸ Cooling degree hours are the summation of hourly temperatures deviated from the threshold temperature of 70°F.

1. Transportation Electrification

According to the California Energy Commission analysis, light-duty EVs accounted for 23 percent of new vehicle sales in California in 2025 and 25 percent in 2023 and 2024.²⁹ SCE forecasts future transportation electrification (TE) load growth broken down by light-duty vehicle (LDV) load and non-LDV load. Non-LDV load includes medium and heavy-duty on-road vehicles, buses, and off-road TE load.³⁰ SCE anticipates continued EV adoption, impacted by recent policy changes including the elimination of federal tax credits. SCE forecasts cumulative light-duty electric vehicles in SCE's service area to reach 1.3 million by 2027.

2. Behind-the-Meter Solar PV Generation

SCE models both residential and non-residential customer adoption of solar photovoltaic (PV) systems through generalized Bass diffusion models. The models fit historical data from NEM and other tariff interconnection reports that are made publicly available on the California Distributed Generation Statistics website.³¹ Historical data reflects incentives such as the Federal Income Tax Credit and its extension in 2023.

H. Total Retail Sales Forecast by Customer Class

Table III-6 below presents SCE's forecast of total electricity sales by customer class. The table shows actual recorded sales at customer meters in 2025 and forecast numbers for 2026 and 2027. The projected average annual growth in total retail sales between 2025 and 2027 is 1.9 percent.

²⁹ California Energy Commission (2025). New ZEV Sales in California. Data last updated on March 31, 2026. Retrieved on May 8, 2026, from <https://www.energy.ca.gov/zevstats>.

³⁰ Such as electric forklifts.

³¹ See <https://www.californiadgstats.ca.gov/>.

Table III-6
Annual Retail Sales by Customer Class
(GWh)

Line No.	Customer Class	2025	2026*	2027*
1	Residential	26,036	26,949	27,534
2	Non-Residential	52,422	51,183	52,410
3	Total Retail Sales	78,458	78,132	79,944
*Forecast				

I. Customer Forecast

Table III-7 below shows SCE's forecast of retail electricity customers. SCE expects the number of customers to increase by 0.6 percent in 2026 and increase another 0.6 percent in 2027. Customer growth is closely tied to activity in the residential construction sector but usually lags by as little as three months and up to two years. A shift in new customer numbers usually reflects changes in housing starts from 3 to 24 months prior.

Table III-7
Year-End Customers by Customer Class

Customer Class	2025	2026*	2027*
Residential	4,645,039	4,675,099	4,706,834
Non-Residential**	704,415	707,542	708,456
Total Retail Sales	5,349,454	5,382,641	5,415,290
*Forecast			
**Includes all except residential customers			

J. Departing Load Assumption

SCE's forecast incorporates the statewide increase in the DA load cap, which started in 2021, as well as new CCA load migration for 2027. SCE's established internal criteria for a qualifying governmental entity to be included in the CCA Departing Load forecast currently is: (1) the filing of a binding notice of intent (BNI) to begin CCA service; (2) an initial RA filing; and either (3) the start of CCA service; or (4) formal submission of an April RA forecast for the following year pursuant to

1 California Public Utilities Code Section 380. The CCAs that meet these criteria for 2027 are listed in
2 the workpapers for Chapter III.

3 Prior to completing its forecast, SCE conducted meet-and-confer opportunities with all CCAs.
4 SCE held meet-and-confers on April 10, 2026, with Clean Power Alliance (CPA) and Orange County
5 Power Authority (OCPA), and on April 22, 2026, with Central Coast Community Energy (3CE). SCE
6 discussed monthly energy and peak forecasts along with other major forecast assumptions for 2027 with
7 CPA, OCPA, and 3CE. In general, SCE reached consensus views with those three CCA entities
8 separately on each side's forecast without finding any major discrepancy.

IV.

UPDATED FORECAST ENERGY PRODUCTION AND COSTS **FROM SCE'S PORTFOLIO OF RESOURCES**

A. Introduction

This chapter describes SCE's resource portfolio and the associated forecast costs that SCE proposes to recover in its 2027 ERRR Forecast revenue requirement. SCE's resource portfolio is comprised of its UOG (which includes nuclear, natural gas, hydroelectric, energy storage, and renewable generation resources); SCE's purchased power resources including CHP and renewable resources, inter-utility contracts and bilateral contracts; and proxy³² (*i.e.*, generic) costs from anticipated future solicitations and market purchases. SCE's 2027 F&PP costs also include procurement contracts to meet the incremental system reliability requirements adopted in D.19-11-016 and procurement contracts to meet mid-term reliability (MTR) procurement requirements adopted in D.21-06-035 and D.23-02-040.

SCE's updated 2027 F&PP cost forecast (Line No. 1 of Table II-1) is projected to be higher than the forecast included in the May Testimony based on both increases and decreases in various cost categories that overall net to a four percent increase as described in Chapter II.

B. Energy Production Forecast Methodology

As with its past ERRR forecast applications, SCE forecasts energy production from its portfolio primarily using the PLEXOS software.³³ The PLEXOS models (1) forecast the least-cost dispatch (LCD) of dispatchable resources in SCE's portfolio;³⁴ (2) optimize hydro dispatch; and (3) perform Monte Carlo simulations of forced outage rates of individual units.

³² The proxy capacity costs are further discussed in Section IV.E.

³³ PLEXOS is a unit commitment software developed and marketed by Energy Exemplar.

³⁴ During the ERRR forecasting process for purposes of rate-setting, the PLEXOS model does not forecast the co-optimization of ancillary services (AS) with energy dispatches (*i.e.*, it does not forecast that energy will be "held back" to allow for the provision of AS). Instead, the model assumes all resources are dispatched for energy only. Because actual AS market revenues are credited to the applicable ERRR proceeding balancing accounts, all revenues SCE actually receives (energy, AS, etc.) are captured during the recording process. In any event, AS revenues are quite small in comparison to energy revenues and are dependent on the CAISO's needs for such services.

1 The simulated dispatch is based on a forecast of power, gas, and GHG prices,³⁵ physical
2 constraints of each generating unit, and contractual limitations. SCE's forecast methodology
3 economically dispatches resources in a least-cost manner as directed by the Commission, rather than
4 force-dispatching resources to meet SCE's forecast of bundled service customer demand. Under the
5 LCD principle, a generating resource or contract is simulated to dispatch if its marginal operating cost is
6 less than the market price of power, while simultaneously observing all operating constraints.³⁶ For a
7 given hour, the difference between the forecast bundled service customer load and the total forecast
8 economic dispatch of SCE's resource portfolio constitutes SCE's projected open position for the hour.

9 SCE based its 2027 power price forecast on the forward power broker quotes for 2027 in effect
10 as of August 24, 2026. The 24-hour flat price as of August 24, 2026, was \$38.64/MWh for 2027. SCE
11 derived its hourly price forecast by applying on-peak and off-peak hourly price profiles to the respective
12 monthly on-peak and off-peak forward quotes for 2027 in effect as of August 24, 2026,³⁷ such that the
13 simple averages of the hourly on-peak and off-peak forecast prices for a particular month match the
14 forward on-peak and off-peak power prices for that month. SCE updated its existing Market Redesign
15 and Technology Upgrade (MRTU)-based statistical models to generate hourly price profiles for the SP-
16 15.³⁸

17 SCE used the ICE settlement price of a 2027-vintage GHG allowance as the basis for its 2027
18 GHG price forecast. The ICE settlement price as of August 24, 2026, was \$34.45/MT for 2027. This

³⁵ The PLEXOS models were not used to develop forecasts of competitive market power or GHG prices. These prices were developed independently, as discussed in the following paragraphs. The GHG price forecast was incorporated as part of the resource dispatch cost similar to natural gas prices in order to reflect the additional GHG cost for the generation resources that have GHG emissions.

³⁶ Energy- and use-limited hydroelectric and peaking resources are also dispatched pursuant to LCD; this analysis also incorporates opportunity cost principles regarding water and emissions limitations, respectively, to ensure that such units are dispatched during higher-priced hours, when it is most economical to do so.

³⁷ SCE used forward prices from the same trading day for power, GHG, and natural gas price forecasts to maintain the consistency of the forward-market outlook.

³⁸ The statistical models incorporated historical MRTU data from the CAISO's Integrated Forward Market (IFM).

price is assumed to be constant for any GHG emissions produced in 2027.³⁹ Last, SCE based its daily natural gas price forecast on monthly NYMEX forward prices at the SoCal Citygate in effect as of August 24, 2026, plus intrastate transportation charges from Southern California Gas Company (SoCalGas), as applicable. The 12-month average NYMEX forward gas price as of August 24, 2026, was \$4.51/MMBtu for 2027. Within a given month, SCE assumed that the daily gas price forecast is equal to the monthly forward price.

C. Validation of SCE's Energy Production Forecast

SCE follows a consistent process to forecast its energy production and costs for the subsequent calendar year, supported by a robust internal validation process. SCE's forecast process is discussed below.

The first stage of SCE's forecast process involves developing all forecast inputs. These inputs include, but are not limited to, SCE's forecast of power, gas, and GHG prices; production from UOG resources (nuclear, hydro, gas, and renewable facilities); CHP and renewable energy production and costs; gas hedging costs; and CAISO costs. These inputs are developed and vetted by SCE's Portfolio Planning and Analysis management.

Once approved, the forecast inputs are utilized in PLEXOS, which is an industry-standard production cost model capable of modeling various types of resources with differing constraints. SCE uses PLEXOS to forecast its LCD activities. Once the dispatch results are produced, SCE conducts a thorough validation of the dispatch outcomes by resource.⁴⁰ If necessary, SCE will rerun the previous forecast steps if it believes more accurate dispatch results can be realized.

Once dispatch results are validated, all energy and cost forecasts are input into SCE's ERRA forecasting tool, an internally developed, automated software program that aggregates the hourly energy production and cost forecast data. The ERRA forecasting tool produces the ERRA forecast tables

³⁹ In prior years, direct and indirect GHG costs were reviewed in a separate GHG Cost and Revenue Forecast application. Pursuant to D.14-10-033, they are now reviewed in this proceeding and are discussed in further detail in Chapters IV and VII.

⁴⁰ For example, SCE compares its dispatch results against prior ERRA Forecasts and reviews any significant discrepancies to ensure that its results are reasonably justified.

1 included in the following section(s). Prior to inclusion in SCE's ERRRA Forecast filing, the forecast
2 tables are reviewed and approved by SCE's senior management.

3 **D. Updated 2027 Energy and Cost Forecast Summary**

4 Because this Application is designed to forecast SCE's energy-related costs that will be used to
5 establish retail generation rates in 2027, a single expected scenario forecast is utilized. All production
6 and residual open position forecasts provided in this section are reflected at the CAISO system interface.
7 Table IV-8 summarizes the monthly forecast production from SCE's portfolio and SCE's open energy
8 positions. Table IV-9 summarizes the monthly forecast cost of SCE's purchased power resources
9 accounted for in the ERRRA Forecast-related balancing accounts. The remainder of this chapter provides
10 detailed descriptions of the resources and the underlying forecast assumptions.

Table IV-8
Updated 2027 Energy Forecast of the SCE Portfolio
(GWh)

Energy (GWh)	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Grand Total
Load													
SCE Peakers													
Mountain View													
CHP Dispatchable													
SCE Hydro													
SCE Nuclear													
SCE Storage*													
Renewables**													
Cogeneration													
UOG SPVP													
Interutility***													
LCR Dispatchable													
RNS													

Areas shaded in grey are confidential per D.06-06-066.

- * Includes the net of charging and discharging energy
- ** Includes Renewable sales, VAMO, and offtake adjustments
- *** Includes Hoover

Table IV-9
Updated 2027 Forecast of Fuel and Purchased Power Costs
(\$000)

[illegible]

1 **E. SCE's Utility-Owned Generation and Purchased Power Contracts**

2 **1. Hydro Facilities**

3 SCE's utility-owned hydroelectric portfolio includes large, reservoir-based facilities
4 within the Big Creek system in the western Sierra Nevada Mountains, including the Eastwood pumped
5 storage facility, as well as smaller hydroelectric resources located throughout California. The hydro
6 generation forecast presented in this proceeding reflects expected operations under average hydrologic
7 conditions and is developed to support regulatory reporting and cost recovery, rather than real-time
8 operational decision-making.

9 The Big Creek hydro system is a flexible resource with significant storage and
10 operational capacity. For ERRRA forecast purposes, generation forecasts for Big Creek are developed by
11 integrating historical hydrology, expected water availability, known operational constraints, and planned
12 outages when available. Forecasted operations are constructed to represent economically optimized
13 dispatch consistent with market participation, while respecting reservoir management requirements,
14 physical limitations of the assets, and system reliability considerations. Forecasted production reflects
15 the anticipated allocation of water over time to maximize overall system value under average conditions.

16 The Eastwood powerhouse is a pumped storage resource within the Big Creek Project
17 system and is modeled as both a generating and pumping facility. Pumpback and generation are
18 scheduled based on economic dispatch principles, with pumping generally occurring during lower-value
19 energy periods and generation during higher-value energy periods, subject to operational and system
20 constraints. Eastwood's pumped storage operations are integrated into the overall Big Creek forecast to
21 reflect its role in optimizing system operations.

22 SCE's Eastern Division hydro facilities are predominantly run-of-the-river resources with
23 limited storage capacity. As a result, their generation is more directly influenced by hydrologic
24 conditions and water availability. Forecasted production for these facilities is based on historical
25 generation patterns under average hydrologic conditions, adjusted for known outages, asset conditions,
26 and current operational status.

1 SCE has been pursuing the divestment of certain smaller hydroelectric facilities.
2 Facilities that have been approved for sale, are non-operational, or are otherwise expected to be
3 unavailable during the forecast period, are assumed to have zero generation and are excluded from the
4 ERRA Forecast.

5 For the forecast year, SCE assumes an average hydrological year and incorporates the
6 best available information regarding asset availability and planned outages at the time the forecast is
7 developed. Where forward-looking information is limited or uncertain, historical averages and
8 engineering judgment are used to produce a reasonable and internally consistent representation of
9 expected hydroelectric generation for ERRA forecasting purposes. Forecasted utility-owned hydro
10 production, inclusive of pumped storage operations, is shown in Table IV-8.

11 **2. SCE Solar Photovoltaic Generation**

12 SCE's Solar Photovoltaic Program (SPVP) portfolio currently consists of a single, utility-
13 owned photovoltaic facility with an installed capacity of 5 MW AC (6.8 MW DC). This facility remains
14 operational and is included in the 2027 ERRA Forecast.

15 Forecasted energy production for the SPVP facility is based on recent historical operating
16 performance, adjusted as necessary for expected availability and operating conditions. The forecast
17 reflects average expected operating conditions and is intended solely for regulatory cost recovery
18 purposes. SCE's forecast of 2027 SPVP production is shown in Table IV-10 below.

Table IV-10
2027 Forecast of SCE SPVP Production
(GWh)

Energy (GWh)	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Grand Total
UOG SPVP													

Areas shaded in grey are confidential per D.06-06-066.

3. CHP and Renewables

a) Energy Forecast

For 2027, SCE forecasts [REDACTED] GWh of energy deliveries from CHP and renewable projects.⁴¹ The energy deliveries from cogeneration and renewable projects are effectively “must take” energy. SCE has [REDACTED] GWh of Product Content Category (PCC)-1 REC sales that have already been executed and forecasts [REDACTED] GWh of PCC-1 REC sales for 2027. Additional information on SCE’s PCC-1 transactions are discussed in Section IX.

Energy deliveries are at the generators’ meters. The projects delivering energy have approximately 11,092 MW of contract capacity allocated as follows:

- [REDACTED] MW of CHP capacity; and
- [REDACTED] MW of renewable capacity.⁴²

SCE uses the historical performance of each project to forecast monthly energy deliveries. From January 2027 through December 2027, eleven solar projects and one geothermal project are expected to begin delivering energy. The eleven projects are under development and are adjusted by their probability of successful development and commercial operation. The total capacity for these projects is approximately 519 MW. Because there are no historical performance data for these

⁴¹ Energy delivery volumes from CHP and renewables refer to the Cogeneration and Renewable line items in Table IV-8. However, the Renewables line item in Table IV-8 is adjusted for actual REC sales and offtake agreement from out-of-state contracts. In addition, the energy delivered at the CAISO accounts for generation loss and excludes energy allocated to serve Green Tariff customers as a part of the GTSR Program described in Section E.13.

⁴² The contract capacity for a project that is not developed is weighted by the project’s expected commercially-operable success rate.

new projects, forecast energy deliveries are based on contractual expectations discounted by their expected probabilities of successful development.

The average annual capacity factors for each of the six renewable technologies are listed in Table IV-11. Average annual capacity factors are based on expected annual energy (adjusted for curtailment) and contract capacity for each project aggregated by technology. In addition, for new, undeveloped projects, both the energy and capacity are weighted by each project's respective probability of successful development.

Table IV-11
Annual Capacity Factors by Technology

Biomass	76.4%
Cogen	75.5%
Geothermal	54.9%
Small Hydro	20.6%
Solar	27.8%
Wind	28.5%

b) Payment Forecast

Payments to CHP and renewable projects delivering energy during 2027 are forecast to be approximately [REDACTED] consisting of [REDACTED] in energy payments and [REDACTED] in capacity payments, as shown in Table IV-12.

Table IV-12
2027 Forecast of Energy and Capacity Payments

	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
Energy GWh													
REC Sales GWh													
Energy Payments \$000													
Capacity Payments \$000													
Total Payments \$000													

Areas shaded in grey are confidential per D.06-06-066.

1 c) Energy and Capacity Prices

2 Energy and capacity prices for each of the CHP and renewable projects are based
3 on the individual project's contract. Many of these projects have contract-specific energy prices. Most
4 Qualifying Facility (QF) projects are paid at the posted avoided cost of energy price. For QF projects
5 with a Standard Offer Contract (SOC), the project's capacity price is either the firm or as-available
6 avoided capacity price depending on the project's specific dedicated capacity. Many of the older QF
7 projects have capacity prices that are contract specific.

8 The posted avoided cost of energy is defined under either the New QF SOC,
9 adopted in D.20-05-006, or the QF SOC adopted in the QF Summit Settlement. The New QF SOC
10 short-run avoided cost (SRAC) for energy identified at time of contract execution is based on a three-
11 year average of the CAISO locational marginal prices for the PNode specific to the QF. The New QF
12 SOC SRAC for energy determined at time of delivery is calculated using locational marginal prices
13 from the CAISO's day-ahead market for the node specific to the QF. The SRAC under the QF Summit
14 Settlement is based on the average 12-month forward heat rates. The monthly forecast of SRAC for
15 energy prices under the QF Summit Settlement is included in Table IV-13 below.

Table IV-13
2027 Forecast of Posted Avoided Costs of Energy and Capacity

Avoided Cost Prices		Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27
Energy	¢/kWh	4.50 ¢	4.25 ¢	3.20 ¢	2.80 ¢	2.73 ¢	2.97 ¢	4.05 ¢	4.12 ¢	4.03 ¢	3.54 ¢	4.05 ¢	4.95 ¢
Firm Capacity	\$/kW-year	\$ 91.97	\$ 91.97	\$ 91.97	\$ 91.97	\$ 91.97	\$ 91.97	\$ 91.97	\$ 91.97	\$ 91.97	\$ 91.97	\$ 91.97	\$ 91.97
As-Available Capacity	\$/kW-year	\$ 77.46	\$ 77.46	\$ 77.46	\$ 77.46	\$ 77.46	\$ 77.46	\$ 77.46	\$ 77.46	\$ 77.46	\$ 77.46	\$ 77.46	\$ 77.46

1 Finally, SCE's 2027 ERRA Forecast includes estimated curtailments from its
2 solar and wind portfolios due to economic reasons. SCE carefully assessed the forward market prices to
3 estimate curtailment volumes. The impact of curtailed energy deliveries is included in the energy and
4 payment forecasts.

5 **4. Utility-Owned Natural Gas Facilities**

6 a) SCE Peakers

7 (1) Background and Production

8 In response to Commission direction to address local electric reliability
9 needs in Southern California, SCE constructed a portfolio of black-start capable, dispatchable generation
10 capacity within its service area. These facilities are available to support system reliability and market
11 operations as needed.

12 Forecasted peaker generation is developed using SCE's production cost
13 modeling framework and reflects expected economic dispatch, operational constraints, and maintenance
14 schedules. Generation from these units is included in Table IV-8.

15 (2) Costs

16 Effective with SCE's 2009 GRC decision, SCE transitioned to GRC-based
17 rate recovery for all capacity and non-fuel variable costs associated with its UOG Peakers. The natural
18 gas cost forecast for these peaking units is included in Table IV-9. SCE's October Update includes
19 changes to the outage schedule, as necessary, resource characteristics such as start-up costs, and
20 transportation costs.

21 b) Mountainview Generating Station

22 The Mountainview Generating Station is a utility-owned combined-cycle natural
23 gas facility. SCE includes forecasted Mountainview generation in its production and cost forecasts
24 consistent with Commission authorized cost recovery.

25 Forecasted generation is determined through SCE's standard production cost
26 modeling methodology and reflects expected economic dispatch, unit availability, and operation
27 constraints. Associated fuel and GHG costs are included in Table IV-9.

5. Inter-utility Contract Production

SCE is a party to a major inter-utility contract under which it is expected to purchase and/or exchange capacity and associated energy for various periods through September 2067.⁴³ Prior to the expiration of a similar, earlier agreement, SCE executed a new 50-year agreement with the Western Area Power Administration (WAPA) and the U.S. Bureau of Reclamation (Reclamation) with an initial service date of October 1, 2017. Table IV-14 summarizes this major inter-utility contract.

***Table IV-14
Non-Coincident Contract Capacity Quantities and
Expiration Dates for SCE's Major Inter-utility Contract***

ID	Counterparty	Type of Contract	Inbound Capacity (MW)	Outbound Capacity (MW)	Expiration Date
10045	WAPA/Bureau of Reclamation	Purchase	280.245	0	9/30/2067

The process of forecasting the level of energy deliveries and receipts for inter-utility contracts with dispatchability (*i.e.*, with WAPA-Reclamation) is an inherently complex task. SCE forecasts net inter-utility contract purchases of 157 GWh in 2027.

a) WAPA-Reclamation Agreement

For 2027, SCE has an entitlement of 280.245 MW of contingent capacity and 238.16 GWh of firm energy⁴⁴ from the Boulder Canyon Project (Hoover), marketed by WAPA.

The ongoing drought conditions in the Rocky Mountains decreased the surface elevation of Lake Mead, which is the forebay to the Hoover power plant. As such, the amount of capacity and firm energy available to SCE will be reduced from the amounts described in the previous paragraph. For 2027, the monthly capacity and firm energy available to SCE could range as low as 33

⁴³ Excluded from this total are SCE's "Fringe Service" agreements, which provide for small amounts of energy exchanges among neighboring utilities. These include two contracts with the Department of Defense for the Air Force that SCE presented to the Commission in Advice 2686-E and Advice 1777-E and contracts associated with retail tariffs.

⁴⁴ Firm energy is energy obligated from Hoover under the Hoover Power Plant Act. During periods when Hoover is unable to provide energy in amounts equal to the firm energy, WAPA is obligated to provide any deficit, if requested by the purchaser, at a rate equal to WAPA's cost to acquire.

MW and 8 GWh, respectively. The forecast amount of capacity and energy available to SCE out of Hoover is shown in Table IV-15.

Table IV-15
SCE Entitlement to Hoover Dam Electrical Output for Year 2027
Source: Bureau of Reclamation - CRSR 9/2026 Most Probable Inflow

Hoover Dam - Lake Mead (September 2026 24-Month Study)						
Date	Reservoir Elev End of Month (Ft)	Hoover Gen Capacity (MW)	Hoover Gross Energy (GWH)	Percent of Units Available	SCE ENTITLEMENT	
					Capacity (MW)	Energy (GWH)
Jan-27	1,034	929	158	72	126	8
Feb-27	1,033	596	156	47	80	8
Mar-27	1,027	932	314	76	126	17
Apr-27	1,019	316	230	24	43	12
May-27	1,016	312	231	24	42	12
Jun-27	1,016	311	222	24	42	12
Jul-27	1,018	315	232	24	43	12
Aug-27	1,024	324	219	24	44	12
Sep-27	1,026	974	185	91	132	10
Oct-27	1,025	767	146	72	104	8
Nov-27	1,024	244	174	18	33	9
Dec-27	1,025	278	166	85	38	9
				2,432		128
				Minimum	33	8

b) Inter-utility Contract Resource Costs

During the 2027 Forecast Period, SCE will purchase or exchange capacity and associated energy with WAPA-Reclamation. Table IV-14 and Table IV-15 summarize the estimated amounts of energy attributable to SCE's major inter-utility agreement.

6. New System Generation CAM Contracts

a) Production

Pursuant to D.07-09-044 and the Joint Party Proposal (JPP) adopted therein, SCE will hold the dispatch rights for all New Generation contracts. Energy from these contracts was not used

1 to meet bundled customer load. SCE estimated energy revenue benefits from these resources to be
2 allocated to all customers. Energy revenues are estimated based on LCD.

3 b) Costs

4 Consistent with the New Generation cost allocation decisions,⁴⁵ SCE accounted
5 for the forecast of capacity costs, energy costs, and energy revenue for all the New Generation contracts
6 until their termination.

7 c) Energy Storage from 2015 GRC

8 As part of its 2015 GRC, SCE filed for cost recovery of DESI 2, a 1.4 MW / 3.7
9 MWh system on the Titanium 12 kV circuit, which became operational in 2018 to support the Integrated
10 Grid Project (IGP) through advanced control schemes such as day ahead forecasts, voltage regulation,
11 and limiting. Originally, SCE planned for the resource to serve both reliability and CAISO market
12 participation after the completion of the IGP, but due to project delays and distribution need changes,
13 DESI 2, also known as UOS Titanium, will be used for the remainder of its useful life as a CAISO
14 market resource. [REDACTED]

15 [REDACTED]
16 [REDACTED]

17 SCE will recover storage charging costs and market revenues associated with this
18 resource through the NSGBA, as shown in Table IV-9.

19 **7. System Reliability MCAM Contracts**

20 On November 7, 2019, the Commission adopted D.19-11-016, which directed SCE to
21 procure 1,184.7 MW of incremental system RA capacity to come online between August 1, 2021, and
22 August 1, 2023, subject to certain terms and conditions set forth in the decision.⁴⁶ Accordingly, SCE

⁴⁵ In D.06-07-029, the Commission adopted a CAM that allows the benefits and costs of new generation to be shared by all customers in an IOU's service area. The decision also ordered the IOUs to develop energy auction implementation plans. Subsequently, D.07-09-044 adopted specific auction processes for the distribution of energy rights in new generation contracts, including specific products and cost and benefit sharing mechanisms.

⁴⁶ SCE was required to procure an additional 56.6 MW for the customers of opt-out LSEs. See April 15, 2020 ALJ Ruling issued in R.16-02-007.

1 launched its 2019 System Reliability Request for Offers (SRRFO) in September 2019 with the intent to
2 procure resources to meet the incremental system reliability needs identified in D.19-11-016. SCE's
3 SRRFO had two tracks:

- 4 • Fast Track – for projects to come online by August 1, 2021; and,
- 5 • Standard Track – for projects to come online by August 1, 2022, and August 1,
6 2023.

7 In April 2020, SCE executed seven Fast Track contracts with various energy storage
8 projects, totaling approximately 678 MW of incremental system RA capacity (770 MW nameplate),
9 which were approved in Resolution E-5101.⁴⁷ In December 2020, SCE submitted Advice 4373-E to
10 request Commission approval of five Standard Track contracts with various energy storage projects,
11 totaling 590 MW of nameplate capacity with 260 MW to come online by August 1, 2022, and 330 MW
12 to come online by August 1, 2023. Resolution E-5142 approved execution of the Standard Track
13 contracts.

14 On May 19, 2022, the Commission adopted D.22-05-015, the Decision on Modified Cost
15 Allocation Mechanism for Opt-Out and Backstop Procurement Obligations. D.22-05-015 authorizes the
16 use of non-bypassable customer charges as the means through which to recover MCAM costs from
17 customers of Opt-Out or Deficient LSEs. Pursuant to OPs 2 and 11 of D.22-05-015, on July 18, 2022,
18 SCE submitted Advice 4831-E (Tier 2) to provide the implementation parameters for SCE's MCAM and
19 to establish the MCAMBA. Advice 4831-E specified the cost recovery transfer of the SRPMA recorded
20 costs between the PABA, MCAMBA, and NSGBA. On January 12, 2023, the Commission adopted
21 Resolution E-5240, which approved Advice 4831-E/E-A. SCE completed the transfers from the
22 SRPMA to the PABA, MCAMBA and NSGBA in January 2023. SCE has reflected the implementation
23 of Advice 4831-E/E-A in this Application and has been recording system reliability-MCAM eligible
24 costs and revenues to their respective balancing accounts since January 2023.

⁴⁷ See Advice 4218-E and Advice 4373-E.

1 a) Production

2 For 2027, SCE included both contract costs and revenues from the SRRFO
3 approved contracts, which are segmented by the PABA, MCAMBA, and NSGBA allocations. The total
4 forecast energy from put option contracts is shown in Table IV-9. SCE's bundled service and LSE opt-
5 out customers are responsible for their pro-rata load share. There are no updates to the 2027 production
6 forecast for the SRRFO contracts when compared to the May Filing.

7 b) Costs

8 The forecast capacity costs, charging costs, and revenues for the SRRFO contracts
9 are included in Table IV-9. [REDACTED]

10 [REDACTED] As further discussed
11 below in the MTR RFO section, SCE will be using excess capacity from one of SCE's SRRFO contracts
12 to meet a portion of its MTR obligations, and the costs have been proportionally split between the
13 related balancing accounts based on the amount of capacity used for each compliance obligation.

14 **8. Emergency Reliability Procurement (R.20-11-003)**

15 a) Overview

16 On November 19, 2020, the Commission initiated R.20-11-003 to establish
17 policies, processes, and rules to ensure reliable electric service in California in the event of an extreme
18 weather event in 2021 or 2022. On February 17, 2021, the Commission issued D.21-02-028 directing
19 and authorizing the IOUs to contract for capacity that is available to serve peak and net peak demand in
20 the summer of 2021 and seek approval for cost recovery in rates from all benefitting customers via the
21 CAM. Pursuant to D.21-02-028, SCE procured resources (Emergency Reliability Contracts) to help
22 ensure reliable electric service in summer 2021 and beyond.⁴⁸ In addition, to bolster reliability for
23 summers 2021 and 2022, the Commission issued D.21-03-056 which, among other things, authorized
24 the IOUs to conduct additional procurement to meet the incremental 2.5 percent portion of an
25 "effective" 17.5 percent planning reserve margin (PRM) for the summers of 2021 and 2022 with cost

⁴⁸ See Advice 4415-E.

1 recovery from all benefitting customers pursuant to the CAM, and provided guidance on the treatment of
2 new and existing import allocation rights and the use of excess RA to meet those procurement targets.⁴⁹
3 On December 2, 2021, the Commission approved D.21-12-015, which adopted several supply- and
4 demand-side requirements to ensure there was adequate electric power in the event of extreme weather
5 during times of greatest need in the summers of 2022 and 2023.⁵⁰

6 b) Costs

7 SCE's last Emergency Reliability Contract procured in accordance with D.21-12-
8 015 terminated in September 2026 (at the conclusion of its third and final renewal term). Therefore,
9 there are no costs associated with this procurement in 2027.

10 **9. Mid-Term Reliability Procurement (D.21-06-035, D.23-02-040, and D.26-02-057)**

11 a) Overview

12 On June 24, 2021, the Commission adopted D.21-06-035, which addresses the
13 mid-term reliability needs of the electricity system within CAISO's operating system by requiring at
14 least 11,500 MW of additional NQC to be procured by all of the LSEs subject to the Commission's
15 integrated resource planning (IRP) authority. The capacity requirements are adopted annually,
16 beginning with 2,000 MW by 2023, an additional 6,000 MW by 2024, an additional 1,500 MW by 2025,
17 and an additional 2,000 MW by 2026. With the addition of Western Community Energy's (WCE) MTR
18 resource requirements and the BPROUD's return of customers due to its deregistration, SCE's total
19 requirement is 4,052 MW with 705 MW online by August 1, 2023, 2,114 MW by June 1, 2024, 529
20 MW by June 1, 2025, and 705 MW of long lead-time (LLT) resources by 2026.

21 On February 23, 2023, the Commission adopted D.23-02-040, which required
22 supplemental MTR procurement of 4,000 MWs of NQC in addition to the amounts ordered in D.21-06-
23 035. The additional procurement is required due to updated load forecasting from the California Energy
24 Commission that suggested that electricity demand is increasing and will continue to increase compared

⁴⁹ See D.21-03-056; Advice 4477-E.

⁵⁰ See also Advice 4787-E.

1 to when D.21-06-035 was adopted, the increase and accelerating impacts of climate change, the
2 likelihood of some additional fossil-fueled generation resource retirements that were not anticipated at
3 the time D.21-06-035 was issued, and the likelihood that some delays beyond 2026 in the procurement
4 of LLT resources required by D.21-06-035 will be necessary.⁵¹

5 On February 26, 2026, the Commission adopted D.26-02-057, which requires
6 LSEs subject to the Commission's IRP purview to procure new NQC from non-emitting, storage, and/or
7 resources eligible under the RPS program, with 2,000 MW NQC due online by June 1, 2030, an
8 additional 2,000 MW NQC due online by June 1, 2031, and an additional 2,000 MW due online by June
9 1, 2032.⁵² SCE's total procurement requirements under D.26-02-057 are 696 MW NQC by June 1 of
10 each of the three years, for a total of 2,088 MW NQC, with 522 MW NQC coming from clean firm
11 resources and/or long-duration storage resources by June 1, 2032.⁵³ D.26-02-057 also allowed the IOUs
12 to submit Tier 1 advice letters to claim compliance with the procurement requirements of D.26-02-057
13 for any contract or resource that has already been approved by the Commission for another purpose in
14 another venue.⁵⁴

15 On July 30, 2021, SCE launched Phase 1 of its Mid-Term Reliability Request For
16 Offers (MTRRFO) for incremental resources that could come online in the 2023-2024 timeframe.
17 Consistent with D.21-06-035, SCE's MTRRFO sought zero emitting resources or resources that
18 otherwise qualified under the RPS eligibility requirements that provide incremental RA benefits, long
19 duration storage, and RA to replace Diablo Canyon capacity. On October 20, 2022, and February 23,
20 2023, SCE launched Phases 2 and 3, respectively, of its MTRRFO. Consistent with the initial MTRFRO
21 phase, SCE continued to seek zero emitting resources or resources that otherwise qualified under RPS
22 eligibility requirements that provide incremental RA benefits, long duration storage, and RA.

⁵¹ D.23-02-040, p. 2.

⁵² D.26-02-057, OP 1.

⁵³ *Id.*, Attachment A at A-1.

⁵⁴ *Id.*, OP 16. This is except as limited by OP 3, which requires eligible energy-only resources to come online after the effective date of D.26-02-057 to count toward the procurement requirements.

1 On March 4, 2022, SCE submitted Advice 4739-E to request expedited approval
2 of five energy storage contracts entered into as a result of the Fast Track of SCE's MTRRFO to meet
3 SCE's procurement requirements to provide incremental September NQC to come online August 1,
4 2023, or June 1, 2024. Resolution E-5205 approved Advice 4739-E with an effective date of May 19,
5 2022.

6 On May 19, 2022, SCE submitted its second MTR advice letter, Advice 4800-E,
7 seeking approval of another energy storage contract to meet a portion of its MTR procurement
8 requirements for 2023. Resolution E-5225 approved Advice 4800-E with an effective date of August
9 25, 2022.

10 On August 17, 2022, SCE submitted its third MTR advice letter, Advice 4850-E,
11 seeking approval of five energy storage contracts and the form and substance of a solar photovoltaic
12 contract to meet portions of its 2023 and 2024 MTR procurement requirements. Resolution E-5234
13 approved Advice 4850-E with an effective date of November 3, 2022.

14 On October 28, 2022, SCE submitted its fourth MTR advice letter, Advice 4885-
15 E, seeking approval of four energy storage contracts using the methodology in the Commission staff's
16 effective load carrying capability (ELCC) report to meet portions of its 2023 and 2024 MTR
17 procurement requirements. Resolution E-5251 approved Advice 4885-E with an effective date of
18 January 12, 2023.

19 On December 16, 2022, SCE submitted its fifth MTR advice letter, Advice 4920-
20 E, seeking approval of four energy storage contracts to meet portions of its 2023 and 2024 MTR
21 procurement requirements. Resolution E-5253 approved Advice 4920-E with an effective date of
22 February 23, 2023.

23 On March 20, 2023, SCE submitted its sixth MTR advice letter, Advice 4990-E,
24 seeking approval of six energy storage contracts to meet portions of its 2023 and 2024 MTR
25 procurement requirements. Resolution E-5271 approved Advice 4990-E with an effective date of June
26 8, 2023.

1 On October 20, 2023, SCE submitted its seventh MTR advice letter, Advice
2 5127-E, seeking approval of the contracts procured as a result of the Standard Track of SCE's
3 MTRRFO, [REDACTED] Resolution E-5307 approved Advice 5127-E with
4 an effective date of February 15, 2024.

5 On November 29, 2023, SCE submitted its eighth MTR advice letter, Advice
6 5155-E, seeking approval of seven energy storage contracts to meet portions of its 2025-2028 MTR
7 procurement requirements. Resolution E-5309 approved Advice 5155-E with an effective date of March
8 21, 2024. Resolution E-5309 approved Advice 5155-E with an effective date of March 21, 2024.

9 On January 26, 2024, SCE submitted its ninth MTR advice letter, Advice 5207-E,
10 seeking approval of contracts for two renewable resources procured as a result of Phases 2 and 3 of
11 SCE's MTRRFO for purposes of meeting both MTR procurement requirements and RPS compliance
12 targets. Resolution E-5313 approved Advice 5207-E with an effective date of May 9, 2024.

13 On January 16, 2024, SCE submitted its tenth MTR advice letter, Advice 5194-E,
14 seeking approval amendments made to the [REDACTED] contracts, which were originally approved in
15 Resolution E-5234. Resolution E-5316 approved Advice 5194-E with an effective date of May 9, 2024.

16 On March 15, 2024, SCE submitted its eleventh MTR advice letter, Advice 5248-
17 E, seeking expedited approval of three solar photovoltaic contracts, entered into as a result of Phases 2
18 and 3 of SCE's MTRRFO. These contracts will contribute renewable energy to meet SCE's Diablo
19 Canyon replacement energy requirement pursuant to OP 6 of D.21-06-035. Additionally, the contracts
20 are RPS-eligible resources and will also contribute to meeting SCE's RPS procurement goals.
21 Resolution E-5333 approved Advice 5248-E with an effective date of July 11, 2024.

22 On March 25, 2024, SCE submitted Advice 5257-E,⁵⁵ seeking approval of one
23 procured amended and restated contract entered into as a result of the Standard Track of Phase 1 of
24 SCE's MTRRFO. Resolution E-5334 approved Advice 5257-E with an effective date July 11, 2024.

⁵⁵ On April 10, 2024, SCE supplemented Advice 5257-E, with Advice 5257-E-A, which made a correction to two data values in Table C-2 in the original Advice 5257-E.

1 On June 10, 2024, SCE submitted Advice 5316-E, seeking approval of two Phase
2 2 and Phase 3 MTR contracts for 750 MW of nameplate capacity, expected to provide 562 MW of
3 incremental September NQC. These contracts were procured to satisfy a portion of SCE's 2026 and
4 2027 MTR requirements. Advice 5316-E also sought approval of one existing MTR contract, [REDACTED]
5 for 100 MW of nameplate capacity. The initial contract was originally approved in Resolution E-5205.
6 This amendment addresses the project's viability issues by extending the expected initial delivery date
7 and increasing the price. The MTR contract will provide an incremental 91 MW of NQC to meet SCE's
8 2024 MTR obligation. Resolution E-5344 approved Advice 5257-E with an effective date August 22,
9 2024.

10 On July 15, 2024, SCE submitted Advice 5336-E, which requested to count 75
11 MW for April 2024, 75 MW for May 2024, 1,654 MW for June 2024, and volumes ranging from 47
12 MW to 110 MW for June 1 through December 31, 2024, from certain bridge firm import energy
13 contracts and resource-specific import RA capacity purchased under an RA swap towards SCE's 2023
14 and 2024 MTR procurement requirements. Advice 5336-E was approved with an effective date of July
15 15, 2024.

16 On October 4, 2024, SCE submitted Advice 5386-E, which requested approval to
17 count 1,270 MW for July 2024, 1,270 MW for August 2024, and 1,180 MW for September 2024 from
18 certain bridge firm import energy contracts towards SCE's 2023 and 2024 MTR procurement
19 requirements. Advice 5386-E was approved with an effective date of October 4, 2024.

20 On November 5, 2024, SCE submitted Advice 5397-E, seeking approval of
21 contracts for three paired (co-located) resources – three solar photovoltaic contracts and three battery
22 energy storage system contracts, entered into through Phases 2 and 3 of SCE's MTRRFO. The contracts
23 represent all the capacity and energy from one project – the Centennial Flats project, which would be
24 brought online in three phases. Additionally, SCE requested the ability to shift MTR compliance
25 tranches for MTR contracts that have already had cost recovery approved by the Commission to account
26 for any project delays and/or terminations. This would potentially involve shifting MTR projects
27 originally contracted and approved to meet the MTR procurement requirements in D.21-06-035 to count

1 towards MTR procurement requirements in D.23-03-040 and vice versa. Resolution E-5365 approved
2 Advice 5397-E, with an effective date of January 30, 2025.

3 On December 5, 2024, SCE submitted Advice 5431-E seeking approval of three
4 MTR energy storage contracts totaling 620 MW of nameplate capacity. These three contracts are RA
5 capacity with financial settlement for new in-front-of-the-meter (IFOM) storage projects. Resolution E-
6 5371 approved Advice 5431-E, with an effective date of February 20, 2025.

7 On December 23, 2024, SCE submitted Advice 5446-E seeking approval to count
8 three bridge firm import energy contracts for June 2025 and July through September 2025 towards the
9 energy and capacity portions of SCE's Diablo Canyon replacement procurement requirement, as well as
10 SCE's general MTR capacity requirements. Advice 5446-E was approved with an effective date of
11 December 23, 2024.

12 On January 31, 2025, SCE submitted Advice 5470-E, seeking approval to count
13 1,041 MW for October 2024, 1,005 MW for November 2024, and 895 MW for December 2024 from
14 certain bridge firm import energy contracts and 37.47 MW of effective load carrying capacity for
15 October 2024 of resource-specific RA capacity towards SCE's 2023 and 2024 MTR procurement
16 requirements. Advice 5470-E was approved with an effective date of May 13, 2025.

17 On February 27, 2025, SCE submitted Advice 5487-E seeking expedited approval
18 of two swap contracts, which would be counted for June 1, 2025, through May 31, 2026, towards SCE's
19 Diablo Canyon Replacement energy procurement requirement. Resolution E-5419 approved Advice
20 5487-E, with an effective date of October 30, 2025.

21 On April 7, 2025, SCE submitted Advice 5517-E, seeking approval of one energy
22 storage contract from Phases 2 and 3 of SCE's MTRRFO, and amendments to two geothermal contracts
23 previously executed as parts of Phases 2 and 3 of SCE MTRRFO, that were previously approved in
24 Resolution E-5313. The Cape Station 3 Amendment reduces its contract capacity by 8 MW (from 70
25 MW to 62 MW). The Cape Station 4 Amendment increases its contract capacity by 86 MW (from 250
26 MW to 336 MW). Combined, these amendments raise the total contract capacity of Cape Stations 3 and

1 4 by 78 MW (from 320 MW to 398 MW). Resolution E-5404 approved Advice 5517-E, with an
2 effective date of June 26, 2025.

3 On April 30, 2025, SCE submitted Advice 5537-E, requesting to count approved
4 contracts towards MTR procurement requirements and adjust cost recovery pursuant to D.21-06-035 and
5 D.23-02-040. Specifically, SCE requested to count 910 MW for January 2025, 910 MW for February
6 2025, 907 MW for March 2025, 50 MW for April 2025, and 50 MW for May 2025 from certain bridge
7 firm import energy contracts, and 47.98 MW and 48.71 MW of ELCC for January to May 2025 and
8 June to December 2025, respectively, from three RA purchase contracts that include solar components
9 of six hybrid resources and one solar resource towards SCE's 2024 and 2025 MTR procurement
10 requirements, as applicable. Advice 5537-E was approved with an effective date of May 30, 2025.

11 On August 11, 2025, SCE submitted Advice 5603-E, requesting approval for
12 eight contracts for three projects, two co-located projects and one solar photovoltaic project entered into
13 as a result of Phases 2 and 3 of SCE's MTRRFO. The BigBeau Contracts comprise two solar
14 photovoltaic (PV) contracts and two battery energy storage system (BESS) contracts. The Easley
15 Contracts include two solar PV contracts and one BESS contract, while the Elisabeth Solar Contract
16 consists of a single solar PV contract. These solar PV MTR contracts will supply renewable energy in
17 support of SCE Diablo Canyon replacement requirement. Furthermore, the solar PV MTR contracts are
18 classified as RPS-eligible resources and will contribute toward SCE's RPS procurement objectives and
19 broader clean energy targets. Additionally, SCE is seeking approval for Amendment No. 3 to an
20 existing BESS contract (Gateway), which was originally executed as part of Phase 1 of SCE's
21 MTRRFO. The Gateway Contract received approval from the Commission in Resolution E-5205.
22 Amendment No. 3 proposes to extend the initial delivery date of the Gateway Contract to June 1, 2027,
23 providing additional time for commercial operations to commence following a thermal event at the
24 facility in May 2024. Resolution E-5428 approved Advice 5603-E, with an effective date of November
25 20, 2025.

26 On May 4, 2026, SCE submitted Advice 5814-E, requesting to count approved
27 MTR contracts towards the D.26-02-057 requirements and adjust cost recovery pursuant to D.26-02-

057. Specifically, SCE sought approval to count three MTR contracts that were previously approved by the Commission towards D.26-02-057 procurement requirements. The contracts are for energy-only solar PV resources that are co-located with fully deliverable BESS, which were originally procured to meet SCE's Diablo Canyon replacement energy MTR procurement requirement pursuant to D.21-06-035. Advice 5814-E was approved with an effective date of May 4, 2026.

b) Costs

The forecast capacity costs for the MTR Contracts are included in Table IV-9 (see "PABA 2021," "PABA 2023," and "PABA 2026" for reference). [REDACTED]

[REDACTED]

[REDACTED]

In the 2026 ERRRA Forecast, SCE revised cost recovery for certain projects due to the reallocation of capacity to meet MTR requirements. This adjustment pertains to two contracts. The first contract, Silver Peak I, was previously requested in Advice 4373-E for SCE's SRRFO and approved in Resolution E-5142. Cost recovery was further addressed in Advice 4831-E, which implemented MCAM and its associated balancing account. In Advice 4373-E, SCE indicated its intention to apply any surplus from the SRRFO procurement toward MTR obligations as outlined in D.21-06-035. Advice 4831-E was approved in Resolution E-5240. SCE has transferred costs related to surplus capacity from the MCAM project, which records to the 2019 subaccount of the PABA, the MCAMBA and the NSGBA, to the 2021 subaccount of the PABA to be used for MTR compliance, based on the pro-rated capacity used towards each compliance requirement. Furthermore, as previously indicated, SCE has segmented cost recovery for the Atlas Solar VIII project between the 2021 and 2023 subaccounts of the PABA based on the amount of capacity used to satisfy the different MTR compliance obligations. Authority to move contract cost recovery between tranches was requested in Advice 5397-E and granted in Resolution E-5365. In addition to the previously referenced contracts, SCE also revised cost recovery for two solar agreements submitted in Advice 5603-E, reflecting a modification in the applicable MTR tranche. Resolution E-5428 granted SCE authority to reallocate the benefits and costs associated with these MTR contracts between the 2021 and 2023 PABA sub-accounts.

1 SCE has not included any forecast costs related to procuring bridge imports to
2 meet MTR compliance. In D.25-09-007, which adopted, with modifications, SCE's Petition for
3 Modification (PFM) of the MTR bridging requirements, the Commission approved an alternative MTR
4 compliance mechanism that allowed LSEs to be deemed compliant with their MTR procurement
5 obligations, including for LTT resources and Diablo Canyon replacement resources, if they can show
6 that:

- 7 1. they have sufficient executed long-term (ten years or more) contracts (for
8 capacity and/or energy, as applicable) to meet the applicable MTR
9 procurement obligation;⁵⁶ and
- 10 2. they have met their month-ahead system RA obligations for all months in
11 which their procurement is delayed, by the final deadline for curing any RA
12 deficiency.⁵⁷

13 Within R.25-06-019 (the IRP proceeding), SCE files compliance filings twice a
14 year, currently June 1 and December 1. In these filings, SCE reports on all of its MTR contracts,
15 including showing that SCE has sufficient long-term contracts to meet all of its MTR obligations. In the
16 RA proceeding (R.25-10-003), SCE submits month-ahead RA filings that demonstrate compliance with
17 SCE's month-ahead system RA requirements.

18 Finally, for clarity, SCE specifies that it is not seeking approval of any MTR
19 contracts submitted for approval via the advice letter process in this proceeding. SCE only includes a
20 description of the MTR advice letters to support the cost forecast included in this Application.
21

⁵⁶ D.25-09-007, OP 11.

⁵⁷ *Id.*

1 **10. Clean Energy Procurement**

2 a) Overview

3 On February 15, 2024, the Commission adopted D.24-02-047, approving a
4 Preferred System Plan designed to achieve a statewide electric-sector greenhouse gas target of 25
5 million metric ton (MMT) by 2035. The Decision authorized SCE to procure the resources identified in
6 its 2022 individual IRP through competitive solicitations or bilateral negotiations, as market conditions
7 warrant. In addition to this program, the Commission is also considering a Reliable and Clean Power
8 Procurement Program (“RCPPP”) that, if adopted, would establish a programmatic framework for load-
9 serving entity IRP procurement, including reliability and greenhouse gas reduction requirements. In
10 addition to these programs, SCE’s 2025 RPS Procurement Plan forecasts a need to procure up to 29,400
11 GWh by the end of 2030 to satisfy its Compliance Period 6 (2028–2030) requirements.

12 On October 7, 2024, SCE launched its 2024 Clean Energy Request for Offers
13 (RFO) to procure new resources under D.24-02-047 and meet its RPS procurement needs. At the time,
14 SCE had received offers through its Midterm Reliability RFO (“MTRRFO”) for thousands of MW of
15 RPS-eligible projects beyond those needed to satisfy its midterm reliability procurement requirements.
16 To expedite procurement and efficiently evaluate the substantial volume of available projects and
17 capacity, SCE transitioned those offers directly into the Clean Energy RFO evaluation, selection, and
18 negotiation process.

19 On November 18, 2025, SCE submitted Advice 5688-E, which sought expedited
20 approval of contracts for solar photovoltaic resources and paired resources using solar PV co-located
21 with battery energy storage systems entered into as a result of SCE’s 2024 Clean Energy RFO. All
22 Clean Energy Contracts are also designed and planned to qualify for tax credits under the Inflation
23 Reduction Act (“IRA”), as modified by the One Big Beautiful Bill Act (“OBBBA”). Advice 5688-E
24 was approved by Resolution E-5445 on February 5, 2026.

1 b) Production

2 SCE's 2027 ERRR forecast includes two solar projects with energy production.
3 These contracts are incorporated into Table IV-8, above. SCE previously included these resources in its
4 initial May Filing but has updated the generation forecast for October.

5 c) Costs

6 SCE has three contracts from its 2024 Clean Energy RFO that come online in
7 2027. The storage contracts are found in the Resource Adequacy Purchase section and the solar
8 contracts are found in the CHP and Renewables section of Table IV-9.

9 **11. Generic and Bilateral RA Contracts**

10 a) Overview

11 For 2027, SCE estimates a system capacity need that varies by month and projects
12 the amount of RA it will need to meet its compliance obligations in 2027 after accounting for existing
13 RA contracts, if short in any months. By estimating its position each month, SCE utilizes strategies to
14 either fill a short position by procuring additional resources or trying to sell surplus RA for periods in
15 which SCE has a long position.

16 b) Generic RA Purchase Costs

17 [REDACTED]
18 [REDACTED]
19 [REDACTED] 58
20 [REDACTED]
21 [REDACTED]
22 [REDACTED]

58 [REDACTED]

1 c) Excess RA Sales Revenue

2 For 2027, SCE calculated its Month-Ahead RA position based on its RA
3 requirements and the available supply to meet its RA requirements. As part of the methodology for
4 forecasting generic sales, SCE allocates its generic procurement for System, Local, and Flexible RA
5 according to its excess sold and unsold forecast; however, since there is now only one RA MPB, all
6 three products use the same price. Any amounts above SCE's RA requirements plus a buffer is assumed
7 to be excess RA. SCE utilizes a framework to attempt to monetize the value of its excess RA, as
8 described more fully in Chapter IX.

9 **12. Local Capacity Requirement (LCR) Contracts**

10 On February 13, 2013, D.13-02-015 authorized SCE to procure between 1,400 MW and
11 1,800 MW of electrical capacity in the Western Los Angeles Basin (LA Basin) sub-area and between
12 215 MW and 290 MW in the Moorpark sub-area to meet LCR by 2021. The Commission determined
13 that the LA Basin LCR existed largely due to the anticipated retirement of once-through-cooling (OTC)
14 generation facilities. Subsequently, on March 13, 2014, the Commission issued D.14-03-004, ordering
15 SCE to procure an additional 500 MW to 700 MW by 2021 to address local capacity needs resulting
16 from the retirement of the San Onofre Nuclear Generating Station (SONGS). In aggregate, D.13-02-015
17 and D.14-03-004 directed SCE to procure between 1,900 MW and 2,500 MW in the LA Basin. These
18 directives required SCE to procure minimum amounts of specific resources, including preferred
19 resources, energy storage, and gas-fired generation. Specifically, the Commission mandated that SCE
20 procure at least 550 MW of preferred resources, 50 MW of energy storage, 1,000 MW of gas-fired
21 generation, and an additional 300 MW from any resource type.

22 On September 12, 2013, SCE launched its LCR RFO to procure specified amounts of
23 preferred resources,⁵⁹ energy storage, and gas-fired generation in the LA Basin and Moorpark local
24 reliability areas. On November 21, 2014, SCE filed A.14-11-012 for approval of 63 contracts executed

⁵⁹ Preferred resources are defined as cost-effective EE, demand response, renewable resources, and distributed generation. See State Energy Action Plan II at p. 2.

as a result of its 2013 LCR RFO for the LA Basin. On November 19, 2015, the Commission issued D.15-11-041, which approved, in part, SCE's request.

a) Production

The LCR contracts included in the forecast are behind-the-meter and in-front-of-the-meter resources. Table IV-8 provides the forecast for monthly energy from the in-front-of-the-meter LCR resources. Behind-the-meter LCR resources reduce the overall bundled service customer load requirement.

b) Costs

The capacity costs are forecasted in the LCR costs line item in Table IV-9. For 2027, the

SCE has updated the associated energy and fuel costs for the new price forecast and model updates.

13. Preferred Resource Pilot (PRP)

On September 24, 2015, SCE launched its PRP RFO #2 to solicit electrical energy, capacity, and renewable attributes from eligible resources such as Demand Response, Renewable Distributed Generation, Energy Storage, Renewable Distributed Generation paired with Energy Storage and Permanent Load Shifting. On November 4, 2016, SCE filed A.16-11-002 seeking approval for the contracts executed during the PRP solicitation. On July 12, 2018, A.16-11-002 was approved; therefore, SCE's 2027 ERRF Forecast includes the costs and production of these contracts.

a) Costs

The capacity costs are forecasted in the PRP cost line item in Table IV-9.⁶⁰

14. Green Tariff Shared Renewables (GTSR) Program

In D.15-01-051, the Commission approved, with modifications, SCE's proposal to implement a GTSR program to comply with Senate Bill (SB) 43. The GTSR program provides two options for customers: (i) a green tariff option (Green Tariff (GT) or Green Rate (GR)) that allows

⁶⁰ As described on pp. 81-83 of Exhibit SCE-01 in A.16-11-002, SCE recovers the costs of the PRP behind-the-meter energy storage contracts from customers through the PPPC.

1 customers to allocate either 50 percent or 100 percent of their electricity bill to renewable energy; and
2 (ii) an enhanced community renewables (ECR) option that allows customers to support renewable
3 energy in their local community via agreements with third-party renewable energy developers. D.15-01-
4 051 authorized the IOUs to seek approval of a GTSR standard contract through changes to the
5 Renewable Auction Mechanism (RAM) standard contract using a Tier 2 advice letter. The Commission
6 adopted further guidelines for the GTSR Program in D.16-05-006, D.17-07-007, and D.19-05-031, and
7 Resolutions E-4734 and E-5028.

8 Starting in or around May 2022, SCE experienced a significant increase in demand for
9 the GTSR-GR program when it enrolled new customers and identified several more interested
10 customers, that if enrolled, would have exceeded SCE's available capacity of 60 MW. SCE's 2026
11 ERRRA Forecast includes projects procured to meet this increased demand.

12 On June 2, 2022, SCE started waitlisting new customer enrollments to avoid over-
13 subscribing the program until enrollment space opened or SCE could procure incremental GTSR-GR
14 capacity. In response, SCE conducted its first solicitation to procure incremental capacity. On June 10,
15 2022, SCE submitted Advice 4814-E to seek approval of two solar photovoltaic projects resulting from
16 SCE's Enhanced Community Renewable Auction Mechanism 7 (CR-RAM 7) solicitation. On June 14,
17 2023, SCE submitted Advice 5050-E to seek approval of one PPA resulting from SCE's 2022 GTSR
18 solicitation.⁶¹

19 On May 30, 2024, the Commission issued D.24-05-065, modifying both the Green Rate
20 and ECR programs. The modified Green Tariff removes certain requirements that have constrained
21 procurement under the previous tariff. In addition, the decision closes the ECR tariff to new
22 procurement not currently under negotiation or contract. As a result, the Commission reassigned the
23 unprocured capacity under the ECR tariff to the modified Green Tariff but caps the total capacity at 562
24 MW with subscriptions capped at 40 MW per customer (which IOUs can request increases for via a Tier
25 2 advice letter). Customers remain on their otherwise applicable tariff but are "topped off" to achieve

⁶¹ Advice 5050-E was approved by Resolution E-4655, with an effective date of August 31, 2023.

1 100 percent clean energy. Costs related to the modified Green Tariff are recovered from participating
2 customer subscribers.

3 On February 14, 2025, SCE submitted Advice 5479-E requesting approval of three PPAs
4 resulting from SCE's 2023 Green Tariff Enhanced Community Renewables Solicitation. The PPAs are
5 for solar photovoltaic projects, each with a contract term of 20 years. Advice 5479-E was approved with
6 an effective date of March 16, 2025.

7 On April 1, 2025, ALJ Kao issued a ruling that allowed parties to comment on the
8 program implementation and associated issues for a Community Renewable Energy (CRE) Program and
9 the Modified Green Tariff Program established by D.24-05-065. SCE filed comments on April 28,
10 2025, and reply comments on May 8, 2025. On June 11, 2026, the Commission adopted D.26-06-006,
11 the decision *Implementing California Shared Renewables Portfolio*, directing the IOUs to submit
12 implementation plans for the Modified Green Tariff (MGT) Program adopted in D.24-05-065.⁶² As
13 implementation of the MGT Program does not affect SCE's 2027 ERRA Forecast, SCE does not reflect
14 any GTSR-GR or MGT Program-related changes in this updated testimony.

15 SCE forecasts Green Tariff participation in 2027 to be 78,701 MWh and ECR
16 participation to be 163,223 MWh, which is a decrease in the Green Tariff participation and an increase
17 in the ECR participation from 2026.⁶³ Green Tariff-specific projects that were procured to serve GTSR
18 customers are online and expected to be producing power in 2027. Three of the projects serving the
19 GTSR-ECR program are currently online, and another three are expected to be online and producing

⁶² In compliance with D.26-06-006, SCE submitted Advice 5889-E to establish the MGT Program and seek approval of its implementation and transition plans for the GTSR-GR. SCE proposes to begin MGT implementation in 2028 and, subject to Commission approval of Advice 5889-E, will incorporate the necessary MGT Program-related details in a future ERRA Forecast Application.

⁶³ D.15-01-051 states that "[i]t is appropriate for an IOU to provide a summary and true-up of costs and revenues against charges and credits applied to Green Tariff Shared Renewables (GTSR) customers on an annual basis, either through the IOU's annual ERRA or in a separate application." This decision also references the IOUs submitting annual Tier 2 advice letters "summarizing the true-up of costs and revenue against charges and credits applied to GTSR customer bills." In accordance with this guidance, SCE submitted Advice 5488-E on February 27, 2025, to update the GTSR program rate components for 2025. SCE also submitted the GTSR Annual Progress Report on March 13, 2026, to update the 20-year forecast of bill credits and charges for SCE's GTSR program.

1 power in 2027. [REDACTED]
2 [REDACTED]

3 SCE's forecasted GTSR-GR rate is set forth in Schedule GTSR-GR, which was most
4 recently updated in Advice 3525-E. As stated in Advice 3525-E, once projects built specifically for the
5 Green Tariff program (referred to as "Green Rate Dedicated Procurement Projects") achieve commercial
6 operation, the costs recorded in the GTSRBA will use the weighted average of the contract costs of the
7 Green Tariff projects averaged with the "Interim Green Rate Pool," if necessary. The weighted average
8 price of the Green Tariff program is calculated based on the GR-specific contracts, which is comprised
9 of the Interim Green Rate pool of PABA projects. Costs related to the Green Rate program are removed
10 from all PABA-related costs. To account for the GTSR program in SCE's 2027 forecast, SCE included
11 Green Tariff line items in Table IV-9 and adjusted the CHP, renewables energy, and cost forecast
12 accordingly. The forecasted kWh required to serve Green Tariff customers are removed from the CHP
13 and Renewables energy and shown separately.

14 In accordance with the program structure, SCE forecasts the costs of its ECR projects [REDACTED]
15 [REDACTED]
16 [REDACTED]
17 [REDACTED]

18 **F. Other SCE Resources and Programs**

19 **1. Nuclear**

20 **a) Production**

21 SCE has an ownership interest in two nuclear generation stations – Palo Verde
22 Nuclear Generating Station (PVNGS) and San Onofre Nuclear Generating Station (SONGS).

23 SCE is a minority owner of PVNGS Units 1, 2, and 3, having a 15.8 percent share
24 that provides a maximum capacity to SCE of 207 MW, 208 MW, 208 MW per unit respectively.⁶⁴
25 Arizona Public Service Company (APS) is the operating utility for PVNGS. For purposes of this filing,

⁶⁴ Maximum Dependable Capacity (MDC).

SCE assumes that PVNGS operates in a baseload manner. PVNGS Unit 3 is scheduled to commence a [REDACTED] refueling and maintenance outage on [REDACTED] and PVNGS Unit 2 is scheduled to commence a [REDACTED] refueling and maintenance outage on [REDACTED]. The total forecast 2027 production from SCE's share of PVNGS is shown in Table IV-8.

SCE is the majority owner and decommissioning agent of SONGS Units 1, 2, and 3. SONGS Unit 1 was permanently retired on November 30, 1992; SONGS Units 2 and 3 were permanently retired on June 7, 2013. SONGS Units 1, 2, and 3 are no longer producing electricity and are being decommissioned.

b) Costs

(1) Overview

This section presents SCE's forecast of its share of PVNGS and SONGS nuclear fuel expenses for 2027. This forecast includes PVNGS generation-related fuel expenses, and PVNGS and SONGS interim spent fuel storage costs. The total 2027 PVNGS and SONGS forecast fuel expenses are included in Table IV-9.

(2) PVNGS Nuclear Fuel Management

SCE incurs a share of the nuclear fuel management costs for PVNGS because PVNGS continues to operate and consume nuclear fuel. Nuclear fuel management consists of a sequence of activities involving the procurement and scheduling of materials and services required to manufacture nuclear fuel assemblies for use in a nuclear generating station, and the disposal of spent fuel assemblies after their discharge from the reactor. These activities encompass: (1) mining and milling natural uranium concentrates (U_3O_8); (2) conversion to uranium hexafluoride (UF_6); (3) enrichment; (4) design and fabrication of fuel assemblies; and (5) spent fuel transportation, interim storage, and permanent disposal. SCE and APS (the PVNGS operating agent) entered into contracts with various suppliers for each of the activities required to procure and manufacture nuclear fuel for PVNGS.

During each refueling and maintenance outage a batch of new fuel assemblies is loaded into the reactor core and one or more batches of fuel assemblies are removed. A

“batch” is a group of nuclear fuel assemblies loaded together into the core of a nuclear generating unit at the beginning of an operating cycle and later removed together at the end of their operating life. The placement of the new fuel assemblies and the fuel assemblies in the remaining batches within the reactor core is based on various reactor core design analyses performed. A batch typically remains in the reactor core for at least two fuel cycles. A fuel cycle begins with a unit’s return to operation following a refueling and maintenance outage shutdown.

(3) PVNGS Nuclear Fuel Expense

SCE projects a nuclear fuel expense for PVNGS of \$30.296 million for 2027. SCE bases this expense on the following factors: (1) amortizing the remaining cost for each PVNGS batch contained in the reactors over the electricity generation expected during the remaining life of each batch; (2) the forecast of electrical generation for each PVNGS unit; (3) the U.S. Department of Energy (DOE) spent fuel disposal charges mandated by the 1982 Waste Policy Act; and (4) interim storage costs for spent fuel assemblies in the dry cask Independent Spent Fuel Storage Installation (ISFSI) located on-site at PVNGS.

Table IV-16 presents SCE’s share of the projected generation-related fuel expense for each PVNGS unit.

Table IV-16
Updated 2027 Forecast Period Nuclear Fuel Expense
(\$000)

Line	Description	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
1	Palo Verde													
2	PVNGS 1 Fuel													\$ 10,800
3	PVNGS 2 Fuel													\$ 9,542
4	PVNGS 3 Fuel													\$ 9,927
5	Spent Nuclear Fuel	\$ 529	\$ 1,133	\$ (1,645)	\$ 27	\$ 695	\$ (714)	\$ 22	\$ 24	\$ (45)	\$ 17	\$ 20	\$ (36)	\$ 27
6	Total PVNGS													\$ 30,296
7	SONGS													
8	Spent Nuclear Fuel	\$ 431	\$ 432	\$ 433	\$ 533	\$ 435	\$ 436	\$ 437	\$ 438	\$ 439	\$ 441	\$ 442	\$ 443	\$ 5,340
9	Total SONGS	\$ 431	\$ 432	\$ 433	\$ 533	\$ 435	\$ 436	\$ 437	\$ 438	\$ 439	\$ 441	\$ 442	\$ 443	\$ 5,340

These expenses are further described in the following sections.

1 (a) PVNGS Unit 1

2 During 2027, Unit 1 will be operating in Cycle 27, with fuel
3 expense reflected in Table IV-16.

4 (b) PVNGS Unit 2

5 During 2027, Unit 2 is forecast to undergo and complete a
6 refueling outage. It is forecast to complete Cycle 27 and commence Cycle 28, with the fuel expense
7 reflected in Table IV-16.

8 (c) PVNGS Unit 3

9 During 2027, Unit 3 is forecast to undergo and complete a
10 refueling outage. It is forecast to complete Cycle 26 and commence Cycle 27, with the fuel expense
11 reflected in Table IV-16.

12 (4) PVNGS Interim Spent Nuclear Fuel Storage

13 Until the DOE implements a program for the permanent disposal of spent
14 fuel, nuclear facility owners must provide interim storage for the spent fuel generated by their facilities.
15 SCE pays for its share of the cost to provide interim storage for the spent fuel generated at PVNGS in
16 the spent fuel pools and in the PVNGS on-site dry cask ISFSI. Because PVNGS Units 1, 2, and 3 are
17 operational, the costs to store spent nuclear fuel in the spent fuel pools, and to transfer fuel from the
18 spent fuel pools to the ISFSI, are operating costs and are not included in SCE's 2027 ERRR Forecast.
19 SCE estimates that it will incur \$2.699 million in costs for its share of PVNGS net interim spent fuel
20 storage costs associated with the dry cask ISFSI during 2027. These costs will be offset by a credit of
21 \$2.672 million arising from a damages award from DOE spent fuel litigation, resulting in a net cost of
22 \$0.027 million, as shown in Table IV-16.

23 (5) SONGS Interim Spent Nuclear Fuel Expense

24 Under the Nuclear Waste Policy Act of 1982, the DOE was contractually
25 obligated to remove spent fuel from SONGS beginning in 1998 but has not yet removed any of the fuel.
26 Until the DOE implements a program for the permanent disposal of spent nuclear fuel, the owner-
27 operators of nuclear generation facilities must provide interim storage for their spent fuel. SCE provides

1 interim storage for spent fuel generated by SONGS Units 1, 2, and 3 in the on-site dry cask ISFSI, and
2 for an additional 270 SONGS Unit 1 spent fuel assemblies that have been temporarily stored at the
3 General Electric-Hitachi facility in Morris, Illinois (GE Morris) since 1972. Because SONGS Units 1,
4 2, and 3 are permanently retired and undergoing decommissioning, the cost to store spent nuclear fuel in
5 the SONGS on-site ISFSI is a decommissioning cost and is paid from the SONGS Nuclear
6 Decommissioning Trusts and therefore is not included in SCE's 2027 ERRR Forecast.

7 In contrast, the annual costs to store the 270 SONGS Unit 1 spent fuel
8 assemblies at GE Morris have been recovered through ERRR Forecast proceedings. However, in D.24-
9 08-001, the Commission ordered SCE to deposit the litigation proceeds from the DOE into its Non-
10 Qualified Nuclear Decommissioning Trust (NQNDT) accounts. The deposited litigation proceeds from
11 the DOE, as well as any investment gains from these funds, shall be used only for the purposes of
12 SONGS spent fuel management and storage costs.⁶⁵ In Advice 5385-E, SCE notified the Commission
13 that it anticipated it would receive the proceeds from Round 5 of SCE's DOE nuclear spent fuel
14 litigation during 2025.⁶⁶ SCE also stated that it expected to deposit the portion of those DOE proceeds
15 attributable to the spent fuel storage at GE Morris into the NQNDT for SONGS 1 in 2026 and to pay for
16 the interim spent fuel costs for SONGS Unit 1 spent fuel stored at GE Morris with funds from the
17 SONGS 1 NQNDT beginning in 2026.⁶⁷ SCE reiterated its expectation to begin paying the interim
18 spent fuel storage costs for the SONGS Unit 1 spent fuel stored at the GE Morris facility with funds
19 from the SONGS 1 NQNDT in its 2026 ERRR Forecast.⁶⁸ However, SCE's Amended October Update
20 in the 2026 ERRR Forecast proceeding no longer forecast that off-site spent fuel storage for SONGS 1
21 spent fuel would be paid from DOE Litigation proceeds, and instead forecast \$5.234 million in interim

⁶⁵ See D.24-08-001, (*Decision Approving the 2021 Nuclear Decommissioning Cost Triennial Proceeding Costs of Southern California Edison Company and San Diego Gas & Electric Company*), pp. 27 and 36; OP 3.

⁶⁶ See Advice 5385-E, dated October 4, 2024, at p. 7.

⁶⁷ *Id.*

⁶⁸ See A.25-05-008, Exhibit SCE-01C, p. 62.

1 storage costs during 2026. SCE stated that it had not received the expected litigation proceeds from
2 DOE and had no expectation of when it will receive those funds.⁶⁹

3 As of October 2026, SCE has not yet received the proceeds from DOE
4 Litigation Round 5 and still has no expectation regarding when these proceeds will become available for
5 SCE to deposit into the NQNDT. Because SCE has no assurance that these funds will be available to
6 pay for the spent fuel storage at GE Morris in 2027, SCE estimates it will incur \$5.340 million in interim
7 storage costs during 2027 for the SONGS Unit 1 spent fuel assemblies temporarily stored at GE Morris,
8 as shown in Table IV-16.

9 After SCE receives proceeds from any DOE Litigation Round 5 or any
10 subsequent litigation round, SCE intends to deposit these proceeds into the NQNDTs after the
11 Commission approves their transfer from the DOE Litigation Memorandum Account (DOELMA) to the
12 NQNDT in an ERRA Forecast Application. SCE will use the portion attributable to spent fuel storage at
13 GE Morris to pay for those costs.⁷⁰

14 **2. Catalina Fuel Costs**

15 SCE provides electric service to Santa Catalina Island by means of six diesel generators
16 and 23 propane-fired microturbines at its Pebbly Beach Generating Station.

17 SCE forecasts the 2027 consumption of diesel fuel on Santa Catalina Island to be 49,572
18 barrels based on 2025-2026 recorded data shown in Table IV-17. Because diesel is the main generation
19 fuel on the Island and storage is limited, SCE purchases diesel fuel throughout the year in the Los
20 Angeles market.

21 SCE forecasts diesel fuel prices for 2027 by using 2025-2026 recorded data.⁷¹ The
22 resulting average commodity cost (plus transportation) is \$160.82 per barrel. After adding the projected
23 cost increase (based on the IHS Global Insight Variable for Gasoline and Fuels), SCE's updated average

⁶⁹ D.25-12-028, p. 45.

⁷⁰ See A.25-05-008, Exhibit SCE-05A, p. 72.

⁷¹ Due to political instability in the Middle East, diesel prices in California have experienced a significant increase in 2026. As SCE is unable to determine the longer-term impact, it has not changed its forecast methodology.

1 delivered diesel fuel cost (plus transportation) is estimated to be \$160.44 per barrel, as shown in Table
2 IV-17.

Table IV-17
Catalina Diesel Fuel
2027 Forecast Delivered Diesel Cost
(2025-2026 Recorded)

Date	Barrels Purchased	Invoice Total	Barge Fee (\$5.10/lb per Tanker Weight) 6% Fuel Surcharge added 6/29/22	Delivery Fee (Fixed \$795 Charge per Tanker)	Total Transport. Cost	Total Cost per Barrel	Total Fuel Cost Forecast for 2027	Total Cost per Barrel Forecast for 2027
Mar-25	3,182	\$439,424.96	\$49,424.10	\$13,515.00	\$62,939.10	\$157.88	\$502,364.06	\$157.88
Apr-25	3,910	\$529,614.25	\$64,819.48	\$16,695.00	\$81,514.48	\$156.30	\$611,128.73	\$156.30
May-25	3,907	\$533,567.61	\$64,186.30	\$16,695.00	\$80,881.30	\$157.27	\$614,448.91	\$157.27
Jun-25	3,706	\$537,466.59	\$60,960.86	\$15,900.00	\$76,860.86	\$165.77	\$614,327.45	\$165.77
Jul-25	4,072	\$626,209.36	\$66,915.42	\$17,490.00	\$84,405.42	\$174.51	\$710,614.78	\$174.51
Aug-25	4,628	\$668,518.58	\$76,313.25	\$19,875.00	\$96,188.25	\$165.23	\$764,706.83	\$165.23
Sep-25	5,920	\$870,393.55	\$97,398.82	\$25,440.00	\$122,838.82	\$167.78	\$993,232.37	\$167.78
Oct-25	5,135	\$562,204.42	\$64,073.24	\$16,695.00	\$80,768.24	\$125.21	\$642,972.66	\$125.21
Nov-25	3,382	\$516,969.19	\$55,575.19	\$14,310.00	\$69,885.19	\$173.52	\$586,854.38	\$173.52
Dec-25	3,929	\$534,758.19	\$64,500.51	\$17,595.00	\$82,095.51	\$157.00	\$616,853.70	\$157.00
Jan-26	5,387	\$750,874.44	\$88,517.56	\$25,955.00	\$114,472.56	\$160.64	\$865,347.00	\$158.42
Feb-26	2,414	\$356,137.05	\$39,608.67	\$11,635.00	\$51,243.67	\$168.76	\$407,380.72	\$166.41
Totals	49,572	\$6,926,138.19	\$792,293.40	\$211,800.00	\$1,004,093.40		\$7,912,640.89	
Averages	4,131	\$577,178.18	\$66,024.45	\$17,650.00	\$83,674.45	\$160.82	\$659,386.74	\$160.44

1 Based on the estimated 49,572 barrels to be consumed by SCE on Santa Catalina Island
2 in 2027 and an average cost of \$160.44 per barrel, SCE forecast its 2027 Catalina-related diesel fuel cost
3 to be \$7.913 million. Because Catalina is electrically isolated from the mainland power grid and the
4 requirement to transport diesel fuel by barge, SCE maintains a working inventory of approximately
5 4,000 barrels of diesel fuel.

6 To forecast 2027 propane costs to operate SCE's microturbines, SCE used forecast usage
7 and forecast costs, as shown in Table IV-18. SCE then converted this forecast usage to therms and
8 applied the Catalina Gas G-2 rate schedule, pursuant to D.25-06-013,⁷² which includes a fixed meter
9 charge per month and a base rate charge, a Gas Cost Adjustment Clause (GCAC) charge, and a public
10 utility reimbursement fee charge per therm. This produced a total gas service 2027 forecast cost of
11 \$1.265 million.

⁷² See D.25-06-013, pp. 14-15.

Table IV-18
2027 Forecast Delivered Propane Cost (Micro Turbines)

Month	2027 Therms Forecast	Meter Rate (\$/day)	Meter Charge	Base Rate (\$/Therm)	Base Rate Charge	GCAC Rate (\$/Therm)	GCAC Charge	PUC Reimbursement Fee Rate (\$/therm)	PUC Reimbursement Fee Charge	Total (2027 Forecast) (\$)
January	18,000	\$ 15.13	\$ 469.03	\$ 2.53	\$ 45,610	\$ 2.62	\$ 47,206	\$ 0.00350	\$ 63.0	\$ 93,348
February	19,000	\$ 15.13	\$ 423.64	\$ 2.53	\$ 48,144	\$ 2.62	\$ 49,829	\$ 0.00350	\$ 66.5	\$ 98,463
March	19,000	\$ 15.13	\$ 469.03	\$ 2.53	\$ 48,144	\$ 2.62	\$ 49,829	\$ 0.00350	\$ 66.5	\$ 98,508
April	19,000	\$ 15.13	\$ 453.90	\$ 2.53	\$ 48,144	\$ 2.62	\$ 49,829	\$ 0.00350	\$ 66.5	\$ 98,493
May	19,000	\$ 22.70	\$ 703.58	\$ 3.28	\$ 62,405	\$ 2.64	\$ 50,086	\$ 0.00350	\$ 66.5	\$ 113,261
June	19,000	\$ 22.70	\$ 680.88	\$ 3.28	\$ 62,405	\$ 2.64	\$ 50,086	\$ 0.00350	\$ 66.5	\$ 113,238
July	19,000	\$ 22.70	\$ 703.58	\$ 3.28	\$ 62,405	\$ 2.64	\$ 50,086	\$ 0.00350	\$ 66.5	\$ 113,261
August	19,000	\$ 22.70	\$ 703.58	\$ 3.28	\$ 62,405	\$ 2.64	\$ 50,086	\$ 0.00350	\$ 66.5	\$ 113,261
September	19,000	\$ 22.70	\$ 680.88	\$ 3.28	\$ 62,405	\$ 2.64	\$ 50,086	\$ 0.00350	\$ 66.5	\$ 113,238
October	19,000	\$ 22.70	\$ 703.58	\$ 3.28	\$ 62,405	\$ 2.64	\$ 50,086	\$ 0.00350	\$ 66.5	\$ 113,261
November	19,000	\$ 15.13	\$ 453.90	\$ 2.53	\$ 48,144	\$ 2.62	\$ 49,829	\$ 0.00350	\$ 66.5	\$ 98,493
December	19,000	\$ 15.13	\$ 469.03	\$ 2.53	\$ 48,144	\$ 2.62	\$ 49,829	\$ 0.00350	\$ 66.5	\$ 98,508
Totals	227,000		\$ 6,915		\$660,758		\$596,865		\$ 795	\$ 1,265,332

Accordingly, SCE's total forecast fuel cost for 2027 Catalina generation is \$9.178 million comprising \$7.913 million in diesel costs and \$1.265 million in propane costs.

3. Demand Response

Demand response programs provide either reliability or economic benefits to the electrical system when activated. Reliability-based demand response programs require the participating customers to curtail their load in the event of an anticipated or actual system emergency. SCE does not account for such reliability-based programs in its simulated economic dispatch of supply resources. On the other hand, economic- or price response-based demand response programs provide SCE an opportunity (*i.e.*, option) to request the participating customers to curtail their load when the market price reaches a certain threshold or in hours when it is expected that market prices will reach a certain threshold due to temperature or load conditions.

For purposes of this Application, SCE included the following price-responsive demand response 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).⁷³

SCE forecasts an estimated 4 GWh of energy reductions to be provided by its price-responsive demand response programs in 2027.⁷⁴ This forecast utilizes a combination of SCE's Load Impact Protocols⁷⁵ and opportunity costs that factor in the maximum available hours and events per day/month/year (*i.e.*, use-limitations) by program. The load impact estimates are based on past customer performance and forecasted enrollment rates for program participation. Since the programs are voluntary and enrollment can vary month-to-month, these estimates provide a reasonable assessment of annual load reduction capability.

⁷³ CAISO Business Practice Manual for Demand Response, *Overview of Demand Response Resources*.

⁷⁴ The estimated energy reduction is largely a function of program availability and forecast price. SCE's model triggers these resources when certain price thresholds are reached, while optimizing for the remaining hours available.

⁷⁵ D.08-04-050, Attachment A, *Load Impact Estimation for Demand Response: Protocols and Regulatory Guidance*, California Public Utilities Commission, Energy Division, April 2008 (the Load Impact Protocols).

1 In accordance with D.23-12-005, all demand response incentives are recorded in the Demand
2 Response Program Balancing Account (DRPBA). Year-end balances in the Incentives Subaccount of
3 the DRPBA are transferred to the BRRBA, which will record the differences between the forecasted
4 amounts and the actual incentives paid.

5 **G. CAISO Costs, Load Procurement Charges, and Energy Revenue**

6 CAISO implemented a new market design, known as MRTU, on April 1, 2009. The new market
7 design includes elements such as the IFM, locational marginal pricing (LMP), and congestion revenue
8 rights (CRRs); and operates in a dramatically different manner than the previous zonal market. Due to
9 the complexity of the CAISO market, SCE separates the total costs from the CAISO market into (1) the
10 non-energy-related CAISO costs, (2) load procurement charges, and (3) energy-related revenues earned
11 by resources in SCE's portfolio. SCE forecasts the non-energy-related CAISO costs, load procurement
12 charges, and energy revenues separately, applying different forecasting methodologies as described
13 below. SCE's short-term market exposure is the net of load charges and bundled service customers'
14 share of the eligible portfolio energy revenues, which is consistent with CAISO market procedures.⁷⁶

15 On May 1, 2026, the CAISO implemented two market initiatives, Day-Ahead Market
16 Enhancements (DAME) and the Extended Day-Ahead Market (EDAM), aimed at strengthening system
17 reliability and driving market efficiency.

18 The DAME initiative introduced two new products designed to address the growing variability in
19 net load forecasts and to ensure that sufficient resources are available in real-time operations:

- 20 • Imbalance Reserves: These reserves are created to manage uncertainties in net load and
21 to address differences in granularity between the day-ahead and real-time markets. The

⁷⁶ Historically, SCE has included a single "Short-Term Market Activity Costs" line item that captured the net of the forecast load procurement charges and the forecast energy revenues for SCE's portfolio of resource (previously referred to as SCE's short-term market exposure). As described in prior years' ERRA Forecast testimony, these short-term market activity costs were based on a forecast of SCE's "hourly open energy position" (*i.e.*, forecast bundled service load less forecast production from SCE's generation portfolio, for each hour). Consistent with D.18-10-019, SCE now forecasts 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.

primary objective is to reduce reliance on out-of-market interventions by accurately reflecting the value of flexible reserve resources.

- Reliability Capacity: This product enhances the existing Residual Unit Commitment (RUC) process by introducing a downward reliability capacity product. Reliability Capacity is intended to resolve discrepancies between physical supply and forecasted load by procuring both upward (positive) and downward (negative) capacity, all facilitated through the RUC process.

SCE does not currently include costs associated with the two new DAME products in its 2027 forecast due to uncertainties regarding their market impact at this time.

1. Non-Energy-Related CAISO Costs

SCE's 2027 forecast of non-energy-related CAISO costs is comprised of the net costs of grid management charges (GMC); FERC fees; CRR auction-related costs; ancillary services; CAISO uplift costs; standard capacity product (SCP) costs; and other non-energy-related CAISO costs. SCE considers these costs as the non-energy-related CAISO costs as they are not sensitive to short-term energy market prices. Therefore, SCE assumed that its 2027 non-energy-related CAISO costs, described above, will be equal to its historical costs for the most recent 12-month period (*i.e.*, from January 2025 through December 2025). SCE's 2027 forecast non-energy-related CAISO costs are presented in Table IV-9. The non-energy related ISO costs are unchanged from the May Filing.

2. Load Procurement Charges

Load procurement charges include SCE's estimated cost of procuring load to serve bundled service customers. Load procurement charges are calculated based on multiplying the hourly load net of NEM export adjustments with the hourly SP-15 prices for that hour. Load procurement charges are reported separately in Table IV-9.

a) Emergency Reliability Utility-Owned Storage (UOS)

On December 16, 2021, the Commission adopted Resolution E-5183, which approved SCE's Engineering, Procurement, Construction, and Maintenance contract with Ameresco, Inc. for the engineering, procurement, construction and maintenance of 537.5 MW of energy storage to

1 address summer reliability. As described in Advice 4617-E, SCE plans to initially operate the storage
2 resources as distribution assets interconnected to non-CAISO-controlled facilities. However, in
3 accordance with Resolution E-5259, one of the three sites (*i.e.*, referred to as the “Separator” project)
4 began counting towards SCE’s MTR procurement requirements effective August 1, 2023.⁷⁷ Therefore,
5 in accordance with D.21-06-035 and Resolution E-5259, the costs and benefits of the Separator project
6 are recovered via the 2021 subaccount of the PABA in 2027.

7 For the remaining two sites that will still be operated as distribution assets (*i.e.*,
8 referred to as “Anode” and “Cathode”), SCE will credit energy benefits against the costs of the energy
9 storage resources. The energy benefits will be reflected as reductions to the load procurement charges,
10 which record to the ERRA BA. To ensure that all benefitting customers receive these benefits, SCE
11 debits the ERRA BA for the actual energy benefits received and credits the distribution subaccount of
12 the BRRBA.

13 **3. Energy Revenues**

14 SCE’s forecast of energy revenues is its forecast of energy rents resulting from the
15 dispatch of resources in SCE’s portfolio. The forecast energy revenue is calculated based on SCE’s
16 forecast production from its portfolio multiplied by the SP-15 price at that hour. Energy revenues for
17 SCE’s PABA-, ERRA-, BMNBC-, CGST-, and CAM-eligible resources are reported separately in Table
18 IV-9, and those energy revenues offset (*i.e.*, reduce) the forecast PABA, ERRA, BMNBC, CGST, and
19 NSGBA revenue requirements.

20 **H. GHG Costs and Emissions**

21 **1. 2027 Cap-and-Trade/Invest Costs and Reconciliation of Prior Period GHG Costs**

22 SCE forecasts \$284.486 million of costs as a result of the Cap-and-Invest Program in
23 2027.⁷⁸ Consistent with the GHG Phase 2 Decision, the forecasted costs are calculated by multiplying

⁷⁷ See Advice 4928-E as approved by Resolution E-5259.

⁷⁸ Beginning in 2026, the Cap-and-Trade program is rebranded as the “Cap-and-Invest” program under AB 1207. See also, Section VII.C below related to AB 1207.

1 the forecast GHG emissions volumes by SCE's forecast 2027 proxy price of \$34.45/MT.⁷⁹ Discussed
2 below are the: (1) different categories of GHG costs associated with procured electricity, (2)
3 methodologies used to calculate the volume of GHG emissions associated with each category, (3)
4 forecasted price associated with those GHG emissions, and (4) combination of the volume and price
5 projections to calculate a total GHG cost forecast.

6 a) Sources of GHG Costs

7 SCE began incurring compliance-related costs associated with Assembly Bill
8 (AB) 32 and the CARB's GHG Cap-and-Invest Program on January 1, 2013. SCE will continue to incur
9 costs for the duration of the program associated with its dispatch and purchases of electricity from fossil
10 fuel-fired (or unspecified) resources. The total costs SCE expects to incur as a result of the Cap-and-
11 Invest Program can be separated into "direct costs," which include SCE's compliance costs and
12 procurement contract costs, and "indirect costs," including QF contract payment costs and market
13 purchase costs. Each category and subcategory of SCE's GHG costs are discussed below.

14 (1) Direct GHG Costs

15 Direct GHG costs originate from GHG-emitting power generation sources
16 for which SCE must pay the cost of compliance instruments in order to satisfy its obligations. These
17 obligations can take the form of (1) compliance instrument surrender requirements under the Cap-and-
18 Invest Regulation, which are classified as compliance costs, or (2) physical or financial reimbursement
19 for compliance instruments that must be surrendered to the CARB by third-party generators under
20 contracts with SCE, which are classified as procurement contract costs.

21 (a) Compliance Costs

22 Pursuant to the CARB's Cap-and-Invest Regulation, SCE must
23 physically surrender compliance instruments to the CARB by annual and triennial deadlines to cover
24 (1) GHG emissions measured from SCE's UOG facilities located in California with annual GHG
25 emissions greater than 25,000 metric tons (MT), and (2) electricity that SCE imports into California as

⁷⁹ The forecast proxy price for both direct and indirect GHG costs is based on the ICE allowance futures contracts for the vintage year equal to the forecast year with delivery in December of the forecast year.

unspecified market power (assessed at a default GHG emissions rate of 0.428 MT per MWh), non-zero specified source power (assessed at a CARB-assigned GHG emissions rate specific to the generating facility), or Asset-Controlling Supplier power (assessed at a CARB-assigned GHG emissions rate specific to the entity that supplies the power). As the “First Deliverer” of electricity from these sources into the California market, SCE incurs a compliance obligation to the CARB for these GHG emissions under the Cap-and-Invest Regulation.

(b) Procurement Contract Costs

Under most of SCE’s tolling agreements with in-state gas-fired power generators, SCE contractually bears responsibility for reimbursing the generator for the GHG costs associated with the Cap-and-Invest Program. These costs are calculated based on the quantity of natural gas burned by the generating facility during the settlement period and a contract-specific emission factor, expressed as pounds of carbon dioxide equivalent (CO₂e) per MMBtu. Depending on the contract, SCE may be required to reimburse the tolling counterparty physically with allowances and/or offsets, or financially, based on the previous CARB auction clearing price. Other contracts give SCE the option to reimburse the counterparty physically and/or financially in its discretion.

(2) Indirect Costs

Indirect costs originate from sources of power generation whose GHG costs SCE is not explicitly obligated to pay, but whose GHG costs SCE is exposed to through the effect of GHG on power pricing. This indirect exposure to GHG costs can come from (1) QF contracts in which the power price varies as a function of current market prices for GHG; or (2) wholesale market purchases of electricity in which the cost of GHG compliance obligations is embedded in the market power price.

(a) QF Contract Costs

Unlike non-QF counterparties with procurement contracts, QFs are not reimbursed for the costs associated with their Cap-and-Invest compliance obligations on a one-to-one basis. Instead, pursuant to the New QF SOC adopted in D.20-05-006, QFs receive SRAC pricing based on CAISO locational marginal prices which includes an embedded premium to account for GHG

costs incurred by power generators in the market. Pursuant to the Commission-approved QF CHP Settlement Agreement (Settlement Agreement),⁸⁰ QFs are paid on a monthly basis according to the avoided cost of energy, as discussed in further detail in Chapter IV, Section E.3. Beginning in 2016, the QF resources under the QF Summit Settlement are paid based on a forward market heat rate, which contains an embedded premium to account for GHG costs incurred by power generators in the market.

(b) Market Purchase Costs

The final category of SCE's GHG costs, purchases of electricity from the California wholesale market, also includes an embedded GHG premium. This premium covers the additional costs incurred by in-state generators for purchasing allowances or offsets to meet their Cap-and-Invest compliance obligations. Like with SCE's QF contracts, the GHG premium embedded in the price of wholesale power purchases is a function of the prevailing market heat rate, which serves as a proxy indicator of the fuel efficiency of the marginal generating unit dispatched in the market.

2. GHG Emissions Volume Forecast Methodology

The first input into the calculation of SCE's forecast GHG costs is the total equivalent volume of GHG emissions for which SCE bears financial exposure and responsibility as a result of Cap-and-Invest regulatory, contractual, or market obligations.⁸¹ SCE's methodology for calculating the emissions volumes for which it has a financial exposure associated with its direct and indirect GHG costs is discussed below.

a) GHG Emissions Associated with Direct Costs

For sources of SCE's direct GHG costs, emissions are forecast as a simple function of the volume of energy SCE expects to generate or purchase from each source and the

⁸⁰ The Commission approved the QF/CHP Settlement Agreement on December 16, 2010, in D.10-12-035. For a description of the QF/CHP Settlement and associated "Legacy Amendments," refer to SCE's April 1, 2013 ERRR Review A.13-04-001, Exhibit SCE-02, Chapter IX.

⁸¹ The total GHG emissions volumes do not necessarily reflect the physical volume of GHG emitted into the atmosphere by generating units. The actual emission total may differ from SCE's financial exposure because of contractually agreed-upon emission factors, settlement formulas, and market determination of power prices that may or may not incorporate the full value of compliance instruments associated with the GHG emissions from the dispatched generators.

emissions intensity of the energy produced. This section describes the methodologies for forecasting emissions from the sources of SCE's direct costs which include (1) sources for which SCE carries a compliance obligation under the CARB Cap-and-Invest Regulation and (2) procurement contracts that assign contractual liability for GHG costs to SCE.

(1) GHG Emissions Associated with Compliance Exposure

SCE's compliance costs originate both from its fossil-fuel-fired UOG resources that emit more than 25,000 MT CO₂e per year, and from electricity that SCE imports into the state of California. For 2027, SCE's only UOG resource that is expected to have a compliance obligation under the Cap-and-Invest Program is Mountainview.⁸² Mountainview's forecast GHG emission volume for 2027 is calculated by multiplying its forecasted gas burn by its emission factor. Since the CARB does not publish actual emission factors for specified resources until after emissions data has been reported for the year, SCE estimates the 2027 emission factor for Mountainview by dividing the average actual GHG emissions reported for Mountainview in 2024 by its average actual gas burn as reported by the SoCalGas.

SCE's forecast volume of imports of electricity into the state of California is based on SCE's forecast need to procure firm energy imports to help manage SCE's open energy position and, if applicable, help meet SCE's RA compliance obligations. When SCE considers procuring firm energy imports, the costs of importing electricity are accounted for as part of the decision-making process and include (1) the cost of GHG allowances,⁸³ (2) the cost of line losses between the intertie point and the first point of interconnection into CAISO, and (3) a GMC imposed by CAISO. Because ancillary services are included in any firm electricity that SCE imports, ancillary service charges are subtracted from the marginal cost of importing electricity. The cost of line losses, GMC, and ancillary services are all forecast based on average historical data collected by SCE.

⁸² The UOG Peakers in SCE's portfolio are forecast to emit less than 25,000 MT CO₂e in 2027. As such, the Peakers are not expected to have compliance obligations under the Cap-and-Invest Program.

⁸³ As the "First Jurisdictional Deliverer" under the Cap-and-Invest Program (*i.e.*, the first entity to bring energy into the CAISO zone), SCE is required to purchase and surrender Cap-and-Invest compliance instruments for each MWh of electricity it imports into the CAISO that has an emissions factor greater than zero.

1 To calculate the volume of GHG emissions associated with all of SCE's
2 forecast imports, the forecast total volume of imports is multiplied by the CARB's default emission
3 factor for unspecified power, equal to 0.428MT CO₂e/MWh and a transmission loss factor of 1.02. This
4 calculation methodology assumes that SCE imports only unspecified power.

5 (2) GHG Emissions Associated with Procurement Contracts

6 To calculate the forecast GHG emission volumes for the procurement
7 contracts under which SCE has assumed the costs of Cap-and-Invest Program compliance, the forecast
8 gas burn at the contracted facility is multiplied by the corresponding contract-specific emission factor.

9 b) GHG Emissions Associated with Indirect Costs

10 Unlike with sources of direct GHG costs, the volume of GHG emissions
11 associated with SCE's indirect GHG costs cannot be precisely calculated as a function of energy
12 produced and emissions intensity. Since these GHG costs are embedded in market-based energy costs
13 that vary according to market conditions, SCE must estimate its indirect GHG costs and the emissions
14 associated with them using more complex methodologies that involve some simplifying assumptions.
15 The methodologies for estimating GHG emission volumes associated with QF contracts and in-state
16 market power purchases are discussed below.

17 (1) GHG Emissions Associated with QF Contracts

18 The volume of GHG emissions associated with SCE's QF contracts is
19 forecast according to the Settlement Agreement option selected by each counterparty. The monthly
20 contract prices paid to counterparties are based on forward market heat rates (recalculated monthly) that
21 contain an embedded premium for GHG costs.

22 GHG emissions volume is calculated based on (1) market heat rate, (2) a
23 volume of natural gas, and (3) an emissions intensity per MMBtu of gas. The natural gas input to the
24 calculation is a "gas equivalent volume" that represents the volume of gas for which SCE bears price
25 exposure under the applicable heat rate as provided in the QF contract for that month's payment. Each
26 contract's gas equivalent volume is forecast by multiplying the market heat rate (Btu/kWh) times

forecast energy generation (kWh). The gas equivalent volume is then multiplied by an emission factor of 117 lbs CO₂e/MMBtu⁸⁴ to determine the forecast GHG emissions volume.

In some instances, the monthly market heat rate used to calculate the gas equivalent volume is an average of 12-month forward market heat rates calculated as follows: the forward SP-15 power price for each of the next 12 months, less the applicable operations and maintenance (O&M) value, all divided by the burner tip gas price (*i.e.*, (SP-15 – O&M) ÷ (Gas Price)). Because the market power price used to calculate the forward market heat rate includes an embedded GHG cost, the calculated heat rate is higher than it would be independent of GHG costs. To avoid double counting GHG costs, an additional factor equal to the ratio of the GHG costs to gas costs is included in the calculation, resulting in the following equation to determine the GHG emission volume in instances where the gas equivalent volume is calculated using the forward market heat rate:

$$\text{Gas Equivalent (mmBtu)} * \frac{\text{Gas Price} \left(\frac{\$}{\text{mmBtu}} \right)}{\text{Gas Price} \left(\frac{\$}{\text{mmBtu}} \right) + \frac{\text{GHG Price} \left(\frac{\$}{\text{mmBtu}} \right)}{117 \text{ lbs/mmBtu}}} * 117 \text{ lbs/mmBtu}$$

(2) GHG Emissions Associated with In-State Market Purchases of Electricity

The forecast methodology for GHG emissions from in-state purchases of electricity in the wholesale market is similar in structure to the GHG forecast methodology for SCE's QF contracts. The inputs to the calculation for forecast GHG emissions from market purchases are: (1) SCE's cumulative net position over each month, which is equal to the sum in MWh of SCE's hourly load minus the sum in MWh of SCE's dispatched and must-take generation and financial heat rate option contracts for all hours; (2) the GHG premium embedded in power prices for the month, equal to the power price divided by the sum of the gas price plus the GHG allowance price; and (3) the fixed emission factor of 117 lbs CO₂e/MMBtu, to convert the GHG price from a per-MT basis to a per-MMBtu basis. The formula is as follows:

⁸⁴ This figure represents the emission factor applicable to the U.S. average GHG content of natural gas, as calculated by DOE using 2008/09 emissions data.

$$\text{Monthly net position (MWh)} * \frac{\text{Power Price } \left(\frac{\$}{\text{MWh}} \right)}{\text{Gas Price } \left(\frac{\$}{\text{mmBtu}} \right) + \cancel{\text{MWh}} \text{Price } \left(\frac{\$}{\text{mmBtu}} \right)} * 117\text{lbs/mmBtu}$$

c) Forecast of 2027 GHG Emissions Volumes

Table IV-19 provides SCE's forecast of 2027 GHG emissions volumes by GHG obligation and exposure category on an accrual basis, based on the methodologies described above.

Table IV-19
Updated 2027 Forecast GHG Emissions Volumes
(Metric Tons CO₂e)

Description	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
Procurement Contracts													
SCE-Owned Generation													
Out of State Imports													
Market Purchases													
QF and Non QF Renewable													
Total													

Areas shaded in grey are confidential per D.06-06-066.

1 **3. GHG Emissions Price Forecast Methodology**

2 ICE is a commodity exchange utilized by California energy and emissions markets and is
3 the primary exchange and clearing house for California GHG Cap-and-Invest allowances. SCE's
4 forecast of the GHG price for 2027 is equal to the ICE settlement price for a 2027-vintage GHG
5 allowance with delivery in December 2027. The GHG price forecast is developed using ICE settlement
6 data for the same trade date used to develop SCE's power and gas price forecasts used in this October
7 Update.

8 For the purposes of this October Update, SCE applied the ICE settlement price as of
9 August 24, 2026, which is equal to a GHG allowance price of \$34.45/MT. This price is assumed
10 constant for any GHG emissions generated in 2027.

11 **4. Forecast 2027 GHG Costs**

12 Table IV-20 below provides SCE's updated forecast of \$284.486 million in 2027 GHG
13 costs. The forecast costs shown below are calculated by multiplying the forecast GHG emissions
14 volumes shown in Table IV-19 above by a GHG allowance price of \$34.45/MT, which is the ICE
15 settlement price as of August 24, 2026.

Table IV'-20
2027 Forecast GHG Costs (\$000)

GHG Costs(000)	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
Procurement Contracts													
SCE-Owned Generation													
Out of State Imports													
Market Purchases													
QF and Non QF Renewables													
Total													\$284,486

Areas shaded in grey are confidential per D.06-06-066.

1 **5. Reconciliation of Prior Period GHG Costs**

2 Beginning in 2014, D.12-12-033 (the GHG Decision) requires that the IOUs' GHG
3 applications include a detailed accounting of GHG costs incurred for the previous year and revenue
4 distributed, including customer outreach and administrative costs. Pursuant to currently authorized
5 ratemaking, any disparity between the forecast of GHG costs incorporated into rates and actual GHG
6 costs is captured as a part of the larger balancing account true-up process where total forecast
7 procurement costs are compared to total realized procurement costs. Any over- or under-collection of
8 total actual procurement costs is then applied to the total ERRRA forecast revenue requirement for the
9 following year. The reconciliation of prior-period GHG costs in this section is solely to true-up the prior
10 year's allocation of auction revenues to eligible customers. The methodology for calculating realized
11 GHG costs was finalized by the Commission in its GHG Phase 2 Decision and is reflected in SCE's
12 calculations, as described below.

13 Table IV-21 below presents the reconciliation of SCE's forecast and actual prior period
14 GHG costs based on the methodology adopted in the GHG Phase 2 Decision and provides the
15 information for Template D-2 "Annual GHG Emissions and Associated Costs" consistent with the GHG
16 Phase 2 Decision. The prior period reconciliation for 2027 reflects final amounts recorded in 2025 and
17 amounts recorded through August 31, 2026, and estimated through December 31, 2026, consistent with
18 the methodology established in D.14-10-033.

Table IV-21
Updated Annual GHG Emissions and Associated Costs
(Template D-2)

Line	Description	2023		2024		2025		2026		2027	
		Update Forecast	Recorded	Update Forecast	Recorded	Update Forecast	Recorded	Update Forecast	Recorded (Actuals through August 2026 with Forecast for Remainder of the Year)	Forecast	Recorded
1	Direct GHG Emissions (MTCO₂e)										
2	Utility Owned Generation (UOG)										
3	Tolling Agreements - Physical 1/										
4	Energy Imports (Specified)										
5	Energy Imports (Unspecified) 2/										
6	Qualifying Facility (QF) Contracts										
7	Contracts with Financial Settlement										
8	Subtotal										
9	Total Emissions (MTCO₂e)										
10	Proxy GHG Price (\$/MT) 4/										
11	GHG Costs (\$) 5/										
12	Direct GHG Costs										
13	Direct GHG Costs - Financial Settlement										
14	Subtotal Costs 6/										
15	Total Costs (\$) 7/										
16	Forecast Variance (\$)										

Areas shaded in gray confidential per D 08-08-066, Main section V.C.

1/ Emissions for Tolling Agreement exposures that is settled using inventory.

2/ Electricity importers may claim certain adjustments for renewable energy purchases and reported electricity. These adjustments may reduce a compliance entity's cap-and-trade compliance obligation and are accounted for in Line 5.

3/ SCE considers GHG costs associated with QF Contracts as an indirect GHG emissions obligation, since the GHG costs are embedded in the energy costs for these resources.

4/ Recorded Proxy GHG Price = Average CAISO Daily GHG Allowance Price Index

5/ Beginning in 2022, this table is modified to eliminate indirect GHG emissions and costs per Decision (D) 21-08-024, Advice 4387-E-A,B,C

6/ This is the EERRA Forecast GHG costs

7/ This row shows the approximate total direct GHG costs collected in rates.

1 **I. Hedging Costs**

2 SCE hedges its open energy position—which includes both power and the natural gas utilized by
3 SCE’s UOG, purchased power contracts, and QF contracts—by purchasing the underlying commodities
4 and, when reasonable, call options on the commodities. SCE’s hedging program consists of a market-
5 based approach to buying the underlying commodities based on balanced pricing tiers and a budget-
6 based approach to purchasing call options.

7 SCE’s market-based approach uses fixed-price power and gas forward transactions procured
8 according to a balanced pricing structure for up to a rolling 12-month period. This balanced pricing
9 approach entails hedging defined volumes at prevailing market prices and a portion of the residual open
10 position if market prices fall within historically lower realized levels.

11 **1. Transaction Fees**

12 Transaction fees consist of clearing and exchange fees charged by the NYMEX and ICE,
13 as well as brokerage fees from over-the-counter brokered financial transactions.

14 **2. Option Premiums**

15 The price of an option is reflected as a cost in addition to the forecast cost of power or
16 gas. The option premium is the cost of removing the risk of increased energy prices. SCE is not
17 forecasting any spend on option premiums in 2027 due to market illiquidity but may look to hedge using
18 options should market conditions change.

19 **J. Gas Transportation and Storage**

20 **1. Transportation**

21 For 2027, SCE does not expect to incur costs associated with gas transportation
22 agreements due to the change in SoCalGas’ G-BTS5 rate structure from a fixed reservation charge to a
23 volumetric based charge. Accordingly, SCE does not have an estimated fixed cost of natural gas
24 transportation for 2027. In accordance with D.24-07-009, SoCalGas converted the G-BTS5 rate option
25 to a fully volumetric rate effective December 1, 2024, in compliance with the All-Party settlement.

1 a) SoCalGas Transportation Agreement for Mountainview

2 Effective February 1, 2017, SCE executed a month-to-month contract with
3 SoCalGas for transportation capacity under Rate Schedule GT-TLS under a volumetric rate for
4 Mountainview. There is no fixed component associated with these transportation contracts. SCE
5 expects that this transportation contract will auto-renew for each month during 2027.

6 b) SoCalGas Transportation Agreements for SCE Peak

7 Effective February 1, 2017, SCE executed month-to-month contracts with
8 SoCalGas for transportation capacity under Rate Schedule GT-TLS under a volumetric rate for the SCE
9 Barre, Center, Grapeland, McGrath, and Mira Loma Peak. There is no fixed component associated
10 with these transportation contracts. SCE expects that these transportation contracts will auto-renew for
11 each month during 2027.

12 c) SoCalGas Transportation Agreements for BTS rights

13 Effective October 1, 2026, SCE executed three BTS contracts with SoCalGas for
14 a thirty-seven month term (October 2026 through October 2029) for transportation capacity under Rate
15 Schedule G-BTS5, a volumetric rate. SCE acquired firm rights for 85,777 MMBtu/day for the entire
16 three-year term. Due to the change in the G-BTS5 charge from reservation-based to volumetric-based
17 usage starting December 1, 2024, there is no cost associated with BTS rights.

18 d) Storage

19 SCE does not have a Gas Storage contract for 2027.

20 **K. Subscription Fees**

21 SCE leverages several subscription fees to support and perform key market functions including
22 monitoring independent market data, risk reports, power prices, natural gas prices, emissions prices, and
23 industry news. These subscriptions are also utilized to calculate SRAC energy price for QFs. For 2027,
24 SCE is forecasting non-labor expenses related to these subscription fees in the amount of \$1.047 million,
25 as shown in Table IV-22.

Table IV-22
Updated 2027 Forecast Fuel & Purchased Power Subscription Expenses
(\$000)

Line No.	Name	Amount	Description
1	Platts	\$ 956	Subscription for market data, gas pricing, and power prices
2	Kiodex	\$ 14	Subscription for market data services
3	Argus Media	\$ 11	Subscription for greenhouse gas prices
4	Natural Gas Intelligence	\$ 37	Subscription for natural gas prices
5	Energy Intelligence	\$ 5	Subscription for natural gas spot prices
6	Tullet Liberty	\$ 24	Subscription for broker quotes for power prices
7	Total	\$ 1,047	

L. Allocation of Large Hydro and GHG-Free Nuclear Energy in 2025-2027

On June 8, 2023, the Commission adopted D.23-06-006, the *Decision Addressing Greenhouse Gas-Free Resources, Long-Term Renewable Transactions, Energy Index Calculations, and Energy Service Providers' Data Access*. D.23-06-006 ordered each IOU to indicate whether it elects to provide an interim allocation of large hydroelectric energy for 2024. On July 28, 2023, SCE submitted Advice 5081-E⁸⁵ and elected to provide a voluntary allocation of hydroelectric and GHG-free nuclear energy in 2024. SCE also stated that it intended to modify its annual term of the LSEs' election after 2024 to a multi-year term in conformance with SCE's election,⁸⁶ which would be included in the ERRA Forecast applications made during the first year of subsequent multi-year periods corresponding to an RPS compliance period.⁸⁷

For 2027, SCE has already elected to provide voluntary allocations of large hydroelectric energy as part of a three-year option that spans 2025-2027. SCE also offered voluntary allocations of PCIA-eligible, GHG-Free nuclear energy in that same period. SCE has completed its GHG-Free allocations for 2025-2027 and there will not be additional allocations until 2028.

⁸⁵ Advice 5081-E was approved with an effective date of July 28, 2023.

⁸⁶ Advice 5081-E, p. 2.

⁸⁷ *Id.*, pp. 1-2.

V.

UPDATED FINANCING COSTS

This chapter discusses SCE’s updated 2027 forecast financing costs related to SCE’s F&PP forecast. The forecast financing costs are recorded in various F&PP balancing accounts and the actual ERRA-related financing costs incurred in 2027 are presented in the ERRA Review proceeding.

A. Commission Decisions Regarding Financing Costs and Collateral Costs

Existing Commission decisions authorize SCE to recover actual fuel inventory financing costs and actual collateral costs. D.93-01-027 authorizes SCE to recover actual fuel inventory financing costs.⁸⁸ D.02-10-062, which established the ERRA BA, provides for recovery of fuel and credit costs including collateral costs.⁸⁹

Provisions for the recovery of financing costs associated with the ERRA Forecast proceeding under-collections are specified in D.04-01-048. The decision states that the three-month commercial paper rate index should be applied to under-collected balances.⁹⁰

B. SCE’s Current Short-Term Financings

1. Credit Facility

SCE currently has a \$3.35 billion multi-year revolving credit facility (also referred to as “revolver”) that supports its short-term borrowing requirements including liquidity support for commercial paper⁹¹ and letters of credit and cash collateral for power procurement needs. The revolver carries only a marginal facility fee if no borrowing or other usage is required.

In 2026, SCE exercised an option to extend the revolver one additional year. The revolver now has the following key features:

- \$3.35 billion borrowing capacity;

⁸⁸ D.93-01-027, Findings of Fact (FoF) 23-26, 28, 30-32, Conclusion of Law (CoL) 14, 47 CPUC 2d 682, 696-698.

⁸⁹ D.02-10-062, FoF 23, *mimeo*, p. 71.

⁹⁰ D.04-01-048, *mimeo*, p. 10, OP 4, p. 23.

⁹¹ The SCE commercial paper program requires a backup credit facility so that SCE can redeem commercial paper when it comes due if SCE cannot issue replacement commercial paper.

- May 2029 maturity;
- \$20,000 annual administrative fee;
- 17.5 basis point annual facility fee;
- 107.5 basis point participation fee on any outstanding letters of credit;
- 20 basis point issuer fees on any letters of credit; and
- Adjusted Daily Simple SOFR (Secured Overnight Financing Rate) plus 107.5 basis points borrowing (loan) rate.

The revolver is sized to meet projected collateral requirements, balancing account under-collections, and short-term, general-purpose borrowing needs during its term. Therefore, a pro-rata share of the costs of the revolver, corresponding to the capacity required to support potential collateral requirements and balancing account under-collections, is recovered through the ERRA Forecast proceeding. For 2027, SCE forecasts that [REDACTED] of the \$3.35 billion revolver will be dedicated to providing capacity for collateral and supporting balancing accounts. The various fees and upfront costs associated with this [REDACTED] amount should therefore be recorded in the F&PP-related balancing accounts. Under-collections that are financed by the revolver are charged the appropriate interest rate on the under-collected balance pursuant to D.04-01-048. SCE intends to recover the remaining fees and upfront costs associated with general corporate borrowing, along with general purpose interest costs, through base rates.

2. Collateral Requirements

Collateral requirements can vary with changes in power prices and must be provided to counterparties within a few days of a collateral call. As a result, the capacity for the maximum collateral draw must be maintained at all times. Currently, [REDACTED] of SCE's \$3.35 billion credit facility is dedicated to supporting its collateral requirements and balancing account under-collections, with the remaining [REDACTED] available for general purpose working capital needs. However, should the Commission require SCE to change its planned procurement to meet RA requirements or require SCE to sign additional long-term contracts for other purposes, SCE's collateral requirements will also change.

3. Commercial Paper

In 2027, SCE's \$3.00 billion commercial paper program will finance fuel inventories. SCE's 2027 forecast assumes that the market for A3/P2/F3 commercial paper will remain stable and that SCE will be able to utilize the commercial paper program for its short-term borrowing needs.⁹²

SCE's commercial paper program has the following features:

- \$3.00 billion borrowing capacity;
- A3/P2/F3 rating; and
- 5 basis point annualized dealer fee on each issue.

4. Letters of Credit

For most counterparties, SCE will provide collateral in the form of letters of credit rather than cash. As such, the participation and issuer fees associated with issuing letters of credit under the revolver or via bilateral uncommitted agreements will be charged to the appropriate balancing accounts, and the actual costs are presented in the ERRR Review proceeding.

C. Other Options Supporting Collateral Requirements

As previously discussed, the revolver may not be large enough to support all of SCE's collateral requirements. Therefore, SCE's current credit facility includes an accordion option to increase the credit limit by \$650 million to \$4.00 billion.

⁹² From time to time, SCE may use commercial paper or borrowings against its credit facility to fund cash collateral requirements; however, SCE customarily provides collateral through letters of credit supported by the revolving credit agreement.

VI.

UPDATED CARRYING COSTS

The purpose of this chapter is to set forth SCE's updated 2027 forecast fuel inventory carrying costs (nuclear,²³ natural gas, and diesel fuel inventories), forecast 2027 GHG compliance carrying costs, and forecast collateral carrying costs for inclusion in SCE's updated 2027 ERRA Forecast revenue requirement, which are summarized in Table VI-23 below.

Table VI-23
Updated 2027 Forecast Carrying Costs
(\$000)

Line No.	Description	Carrying Cost
1.	Fuel (Nuclear, Natural Gas, & Diesel)	
2.	Greenhouse Gas	
3.	Collateral	
4.	Total	

A. Updated Fuel Inventory Carrying Costs

SCE's fuel inventory consists of in-core nuclear fuel associated with its ownership interest in the PVNGS, natural gas storage and imbalance, and diesel fuel for the diesel generators on Catalina Island. Total forecast fuel inventory in 2027 includes the forecast fuel inventory plus forecast PVNGS pre-core nuclear fuel. The calculation of the forecast fuel inventory carrying cost is based on forecast average monthly inventory balances for PVNGS nuclear in-core, diesel, and natural gas and the 2027 forecast carrying cost rate. Short-term debt is assumed to finance the total forecast fuel inventory.²⁴ The carrying costs forecast is calculated as the interest on the short-term debt necessary to fund the inventory.

²³ For the purposes of calculating the 2027 ERRA Forecast carrying costs, nuclear fuel includes "in-core" nuclear fuel inventories for PVNGS.

²⁴ Total inventory includes "pre-core" nuclear fuel inventories for PVNGS.

The updated average 2027 ERRA Forecast proceeding forecast fuel inventory balances and associated carrying costs are presented in Table VI-24.

Table VI-24
Updated 2027 Forecast of ERRA Proceeding Fuel Inventory Carrying Costs
(\$000)

Line No.	Description	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
1.	Average ERRA Fuel Inventory Value													
2.	Inventory Carrying Cost													

Areas in gray are confidential per D 06-06-066, Matrix Section V.6.

B. Updated GHG Compliance Carrying Costs

This section discusses the forecast of GHG procurement compliance carrying costs in 2027. SCE is authorized to recover the actual interest expense associated with the cash outlays to meet GHG procurement compliance costs.²⁵ To forecast carrying costs, SCE uses historical GHG inventory balances and the applicable balancing account interest rate²⁶ to finance GHG procurement compliance carrying costs. The updated 2027 forecast GHG procurement compliance inventory and carrying costs are presented in Table VI-25.

Table VI-25
Updated 2027 Forecast of ERRA Proceeding GHG Compliance Carrying Costs
(\$000)

Line No.	Description	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
1.	Average GHG Allowance Inventory Value													
2.	Inventory Carrying Cost													

Areas in gray are confidential per D 06-06-066, Matrix Section V.6.

Table VI-26 sets forth the calculation of the carrying costs associated with SCE's collateral requirements necessary to procure power. This calculation is based on forecast average collateral requirements and the projected terms of SCE's revolvers, discussed in Chapter V.B. As SCE's collateral requirements change during 2027, SCE will use actual collateral requirements in determining the carrying costs.

²⁵ See D.14-10-033, Attachment B, Section G - GHG Accounting Procedures for Ratesetting Purposes.

²⁶ 90-Day Non-financial Commercial Paper Rate as published by the Federal Reserve H-15 report.

Table VI-26
Updated 2027 Forecast of ERRA Proceeding Procurement Collateral Carrying Costs
(\$000)

Line No.	Description	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
1.	Average Collateral Value													
2.	Collateral Carrying Cost													

Areas in gray are confidential per D.98-06-066, Matrix Section V.6.

1 VII.

2 **UPDATED GHG FORECAST REVENUES AND RECONCILIATION**

3 **A. Overview**

4 This chapter updates SCE's (1) forecast of 2027 GHG allowance revenue and revenue returns to
5 eligible customers, (2) forecast of 2027 administrative and customer outreach costs, and
6 (3) reconciliation of the prior period activity to account for differences between actual revenues returned
7 to customers and actual revenues received from the consignment of allowances to the auction, net of
8 actual customer outreach and administrative costs.

9 SCE proposes to return a total of \$551.460 million in net available GHG revenues to eligible
10 customers in 2027 based on the Commission-adopted methodologies and utilizing GHG revenues and
11 Cap-and-Invest costs, including administrative and customer outreach costs as proposed and supported
12 herein. Residential and eligible small business customers can expect a semi-annual, on-bill California
13 Climate Credit of \$47.00 in 2027, which includes accounting for administrative and customer outreach
14 costs, Commission-authorized GHG revenue set-aside for programmatic use, and Emissions-Intensive
15 Trade-Exposed (EITE) revenue returns.

16 Upon Commission approval of this Application, SCE will submit an advice letter to implement
17 changes to its tariffs, as necessary, to include the authorized GHG revenue returns in rates. These
18 changes will include revisions to SCE's residential rate schedules, including master-metered rate
19 schedules, and small business rate schedules to include the authorized 2027 residential California
20 Climate Credit amounts.

21 **1. Rulemaking to Improve the California Climate Credit**

22 On July 24, 2025, the Commission instituted R.25-07-013 to consider measures to
23 improve the effectiveness of the California Climate Credit in supporting customer affordability. This
24 proceeding is being conducted in phases to account for ongoing changes in CARB regulations. Phase 1
25 focuses on matters related to the residential California Climate Credit, while Phase 2 will address issues
26 pertaining to the Small Business Climate Credit and EITE customers. Phase 1 was divided into two sub-
27 phases. Phase 1A addressed near-term actions, including whether to pause the 2026 distributions of the

1 residential California Climate Credit, as well as immediate program modifications to maximize
2 affordability, enhance outreach, and implement the California Transmission Accelerator Revolving Fund
3 (TARF). Phase 1A concluded and is discussed in various sections of this chapter. Phase 1B will
4 consider broader modifications to the residential Climate Credit, including development of guiding
5 principles, goals, and objectives, as well as potential changes to eligibility, timing of distributions,
6 calculation methodologies, and outreach. Phase 1B has been scoped and the Commission anticipates
7 completion in early 2027, allowing enough time for inclusion in the 2028 ERRF Forecast.

8 **2. Updates to GHG Set-Asides Per Assembly Bill 1207**

9 Assembly Bill (AB) 1207, enacted on September 19, 2025, amended Public Utilities
10 Code 748.5, among other things, to: (1) terminate, effective July 1, 2026, the Commission’s authority to
11 allocate up to 15 percent of GHG revenue to clean energy and energy efficiency (EE) projects; and (2)
12 require SCE to remit five percent of allowance revenue to the TARF for the period July 1, 2026, to July
13 1, 2031, to the State Treasury. SCE addresses TARF forecasting and reporting in Section VII.C.3.
14 Matters concerning clean energy program funding have been addressed in A.22-05-002 et al, the
15 Disadvantaged Communities – Green Tariff, Community Solar Green Tariff and Green Share Tariffed
16 Shared Renewables Programs (GAP Proceeding), and R.25-01-005, Order Instituting Rulemaking on
17 Customer Generated Renewables for Priority Communities, and are further discussed in Section VII.C.2.
18 Notwithstanding that GHG funding for clean energy programs is no longer applicable, SCE continues to
19 report on such programs in this section to reconcile prior-period amounts in SCE’s Template D-1 and to
20 provide the associated procedural history.

B. Updated 2027 GHG Allowance Revenue Forecast

SCE forecasts each year's GHG allowance revenue by multiplying the total volume of allowances that the CARB has allocated to SCE for 2027 by a forecast proxy price for these allowances. This is consistent with the GHG Phase 2 Decision adopted methodology for forecasting GHG allowance revenues. SCE has planned consignment volumes in the 2027 CARB auctions as shown in Table VII-27 below.⁹⁷

***Table VII-27
Updated 2027 Forecast Consignment in CARB Auctions
(Metric Tons CO_{2e})***

Line No.	Auction Date	Metric Tons CO _{2e}
1.	February 2027	
2.	May 2027	
3.	August 2027	
4.	November 2027	
5.	Total 2027 Forecast	16,733,510

Areas shaded in gray confidential per D.06-06-066, Matrix section V.C.

The forecast proxy price for GHG allowances for the remainder of 2026 is \$32.51/MT, which was the ICE settlement price for 2026 vintage allowances with delivery in December 2026 as of August 24, 2026. The forecast price for allowances used to calculate SCE's forecast 2027 Cap-and-Invest revenues is \$34.45/MT.

SCE's forecast Cap-and-Invest auction revenues for 2027, calculated by multiplying the expected consignment volumes by the proxy allowance price, are shown below in Table VII-28.

⁹⁷ SCE's forecast 2027 allowance consignments to CARB auctions reflects SCE's annual allocation allowance under the new Cap-and-Invest Regulation, effective September 1, 2026, as well as the Energy Imbalance Market (EIM)-related allocation reduction provided by CARB on August 14, 2026.

Table VII-28
Updated 2027 Forecast Allowance Revenue
(\$000)

Line No.	Auction Date	(\$000)
1.	February 2027	
2.	May 2027	
3.	August 2027	
4.	November 2027	
5.	Total 2027 Forecast	\$ 576,469

Areas shaded in gray confidential per D.06-06-066, Matrix section V.C.

1. Amortization and Reconciliation of Prior Period GHG Allowance Revenues

SCE is providing actual allowance revenue amounts from the February, May, and August 2026 auctions. SCE's forecast for the remaining 2026 auction is based on an updated forecast proxy price for GHG allowances for the remainder of 2026. In accordance with D.14-10-033 and as noted above, SCE uses the ICE futures settlement price for December 2026 deliveries as of August 24, 2026, as a proxy for remaining 2026 auction clearing prices. Table VII-29 below shows the 2026 recorded/forecast GHG allowance revenue amounts.

Table VII-29
Updated 2026 Recorded/Forecast Allowance Revenue

Line No.	Auction Date	(\$000)
1.	February 2026 (Recorded)	
2.	May 2026 (Recorded)	
3.	August 2026 (Recorded)	
4.	November 2026 (Forecasted)	
5.	Total 2026 Fcst./Rcrd.	\$ 679,201

Areas shaded in gray confidential per D.06-06-066, Matrix section V.C.

C. Updated 2027 Proposed GHG Revenue Return

Pursuant to the GHG Decision (D.14-10-033), SCE allocates GHG allowance revenue in this order: (1) forecast annual administration and customer outreach costs; (2) Commission-approved set-asides for programmatic use; and (3) EITE revenue returns. The sections below provide the prior-period reconciliation and the 2027 forecast for each of these items.

1 **1. Prior Period Reconciliation and Forecast 2027 SCE Administrative and Customer**
2 **Outreach Costs**

3 a) Reconciliation of Prior Period Administrative and Customer Outreach Costs

4 D.25-12-028 found SCE's 2026 total administrative costs forecast of \$0.386
5 million (which includes SCE-outreach and IT-related activities) reasonable for the purposes of
6 calculating the 2026 residential and small business California Climate Credit. As detailed in Table VII-
7 30 below, based on recorded costs through August 31, 2026, and forecast costs from September 1
8 through December 31, 2026, SCE expects to incur \$0.441 million of costs in 2026 associated with
9 administrative, customer outreach-related, and IT related activities.⁹⁸ SCE projects the 2026
10 administrative and outreach costs to exceed the 2026 forecasted amount. This increase is mainly
11 attributed to two decisions already issued in the Order Instituting Rulemaking to Improve the California
12 Climate Credit (Climate Credit OIR): (1) D.26-03-013, ordering SCE to pause distribution of the 2026
13 residential California Climate Credit, and (2) D.26-04-036, ordering residential California Climate
14 Credit distribution in August and September 2026. The increased expenses include changes to
15 marketing plans and updates to SCE's internal billing system to accommodate the changes ordered in
16 both decisions.

17 b) Updated Forecast 2027 SCE Administrative and Customer Outreach Costs

18 As shown in Table VII-30 below, SCE is forecasting \$0.314 million in customer
19 GHG Climate Credit-related costs in 2027.⁹⁹ GHG-related administrative and marketing costs are
20 recorded in the Greenhouse Gas Administrative Costs Memorandum Account (GHGACMA), with the
21 majority of the costs associated with the bi-annual residential and small business Climate Credit
22 disbursements. Given ongoing activity in the Climate Credit OIR, SCE cannot yet determine how
23 additional changes may impact its 2027 administrative and customer outreach costs, including necessary

⁹⁸ Costs associated with EITE platform maintenance, auditing, and administration are also included in administrative and customer outreach costs.

⁹⁹ This amount includes routine production and delivery for the Climate Credit mailer each year and EITE-related expenses and is only expected to increase with inflation in future years as it has in the past.

IT costs to modify the internal billing systems. Accordingly, at this time, SCE is unable to forecast administrative and customer outreach and IT-related costs for 2027 related to potential changes as result of Phase 1B.

Table VII-30
Updated Detail of Outreach and Administrative Expenses
(Template D-3)

Line No.	Description	2023		2024		2025		2026		2027	
		Forecast	Recorded	Forecast	Recorded	Forecast	Recorded	Forecast	Recorded ^{1/}	Forecast ^{2/}	Recorded
1	Utility Outreach Expenses (\$)										
2	Customer Call Center	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
3	Marketing - SCE (incl. email, bill inserts)	\$ 325,000	\$ 249,118	\$ 325,000	\$ 235,286	\$ 380,316	\$ 411,766	\$ 385,842	\$ 371,133	\$ 313,843	\$ -
4	Targetbase	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
5	Other - Marketing/Advertising Agency	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
6	Subtotal Outreach	\$ 325,000	\$ 249,118	\$ 325,000	\$ 235,286	\$ 380,316	\$ 411,766	\$ 385,842	\$ 371,133	\$ 313,843	\$ -
7	Utility Administrative Expenses (\$)										
8	IT-related expenses	\$ -	\$ 63,670	\$ -	\$ 670,790	\$ 487,500	\$ 48,500	\$ -	\$ 69,988	\$ -	\$ -
9	Utility Outreach and Administrative Expenses (\$) (Line 6 + Line 8)	\$ 325,000	\$ 312,788	\$ 325,000	\$ 906,076	\$ 867,816	\$ 460,266	\$ 385,842	\$ 441,121	\$ 313,843	\$ -
10	Additional (Non-Utility) Statewide Outreach (\$)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
11	Total Outreach and Administrative Expenses (\$) (Line 9 + Line 10)	\$ 325,000	\$ 312,788	\$ 325,000	\$ 906,076	\$ 867,816	\$ 460,266	\$ 385,842	\$ 441,121	\$ 313,843	\$ -

^{1/} Recorded through August 31, 2026, plus estimated from September 1, 2026 through December 31, 2026.

^{2/} Given ongoing activity in R.25-07-013, SCE cannot yet determine how additional changes may affect its 2027 administrative and customer outreach costs, including IT costs to modify internal billing systems. Accordingly, SCE cannot forecast additional administrative and outreach as well as IT-related costs for 2027 outside of the routine costs.

2. Clean Energy Programs Set Aside Funding

a) Multifamily Affordable Housing Solar Roofs Program (also known as the Solar On Multifamily Affordable Housing (SOMAH) Program)

SOMAH Program funding terminated on June 30, 2026. In addition, AB 1207 amended Section 748.5(c) and discontinued GHG funding for clean energy programs effective July 1, 2026. As a result, SCE does not request SOMAH funding for 2027. Accordingly, Line 14a of Table VII-33 reflects zero GHG funding for the SOMAH Program in 2027.

(1) SOMAH Program Funding True-Up

D.22-09-009 approved the Petition for Modification (PFM) of D.17-12-022 and D.20-04-012, simplifying the process for forecasting and setting aside funding, including approval of the Joint IOU's proposed advice letter true-up process. Subsequently, on July 2, 2026, the Commission adopted D.26-07-029, *Decision Modifying the Solar on Multifamily Affordable Housing Program*,

1 which, among other matters, maintained the existing SOMAH true-up process through the Program Year
2 2026 true-up cycle.^{100, 101}

3 Pursuant to OP 4 of D.22-09-009, the Joint IOUs submitted Advice 5752-
4 E to reflect a final accounting of each IOU's total GHG allowance revenues for 2025 as tracked in the
5 IOUs' respective GHG revenue balancing accounts. The true-up or credit amount for 2025 is the
6 difference between the IOUs' share of the \$100 million cap¹⁰² and the previously approved set aside in
7 the 2025 Erra or ECAC filings. Table VII-31, which was included in Advice 5752-E,¹⁰³ shows a
8 decrease in SOMAH Program funding of \$1.772 million,¹⁰⁴ which results in a credit to the GHG
9 balancing account.

¹⁰⁰ D.26-07-029, p. 30.

¹⁰¹ OP 6 of D.26-07-029 orders that unused SOMAH program funds, including accrued interest, be returned to the Greenhouse Gas Revenue Balancing Account (GHGRBA) after disposition of the final SOMAH budget expenditure Tier 2 AL. Program funds and accrued interest must be included in a future Erra Forecast prior to returning to customers through the Climate Credit. The SOMAH budget expenditure report is due by December 31, 2033.

¹⁰² See D.22-09-009, Table 2, p. 11 for SCE's proportionate share of the \$100 million cap.

¹⁰³ Advice 5752-E, submitted February 27, 2026, was approved on August 27, 2026, with a February 27, 2026 effective date.

¹⁰⁴ Per the request of the Commission's Energy Division, the signs in the Annual Difference column on this table are reversed relative to the entry shown in Table VII-34.

Table VII-31
Updated SOMAH Funding Prior Years True Up
(\$000)

Line No.	SOMAH Funding Prior Years True Up	Recorded GHG Allowance Revenues	Set-Aside Based On 10% Of Recorded GHG Allowance Revenue (or \$100M limit)	Previously Approved "Actual" Set-Aside	Annual Difference
1	2016	\$188,088	\$18,809	\$0	(\$18,809)
2	2017	\$384,894	\$38,489	\$8,077	(\$30,412)
3	2018	\$389,316	\$38,932	\$39,126	\$194
4	2019	\$421,170	\$42,117	\$40,854	(\$1,263)
5	2020	\$420,965	\$42,097	\$73,282	\$31,185
6	2021	\$551,752	\$49,498	\$63,966	\$14,468
7	2022	\$700,179	\$50,135	\$73,365	\$23,230
8	2023	\$789,701	\$50,209	\$46,528	(\$3,681)
9	2024	\$819,525	\$49,856	\$46,528	(\$3,328)
10	2025	\$635,585	\$44,756	\$46,528	\$1,772
11	Total	\$5,301,176	\$424,897	\$438,252	\$13,355

Lines 14b of Table VII-33 below shows SCE's prior period true-up of the 2025 GHG revenue set-asides for the SOMAH Program.

b) Updated Disadvantaged Communities (DAC) Programs

(1) Cost Recovery for All DAC Programs

D.18-06-027 (the DAC Decision) ordered the IOUs (and CCAs) to fund the DAC programs through available GHG allowance proceeds. If such funds were exhausted, the programs would be funded through PPP funds. In early 2021, the CARB informed the IOUs that there was a discrepancy between CARB's Cap-and-Invest Regulation and its prohibition on "volumetric" returns (Section 95892(d)(7)(D) and Section 95802 "Volumetric") and the DAC Decision's requirement to fund the 20 percent bill discount (based on a customer's monthly energy usage) first with GHG allowance proceeds. CARB also clarified that any administrative, IT upgrade(s), and marketing costs that support the administration of the volumetric return also may not be offset with GHG allowance

proceeds. Beginning with the implementation of SCE’s 2022 ERRA Forecast rates, SCE began separately tracking the DAC discounts and related costs and has been recovering these amounts through PPP rates.¹⁰⁵ AB 1207 discontinues the provision for DAC programs to be funded by available GHG allowance proceeds beginning July 1, 2026. Accordingly, Line 16 in the PPP column on Table VIII-35 now reflects the total DAC Program-related funding to be recovered from the PPP rate component, as further described in the sections below, while Lines 14c-14f on Table VII-33 reflect zero GHG funding set-asides.

(2) Updated SCE’s DAC Programs

AB 327 (Perea), Stats. 2013, Ch. 611, directed the Commission to develop “specific alternatives designed for growth [in adoption of renewable generation] among residential customers in disadvantaged communities.” On June 21, 2018, the Commission approved the DAC Decision, which provides assistance in the form of financial incentives towards the installation of solar generating systems on the homes of low-income homeowners. The DAC Decision authorizes the DAC-Single Family Solar Homes (SASH) program to be funded first through GHG allowance proceeds. If such funds are exhausted, the programs will be funded through PPP funds through the conclusion of the program in 2030. SCE’s proportionate share of the \$10 million annual budget starting in 2019 through the end of the program in 2030 is 46 percent per Appendix A of the DAC Decision. On October 8, 2026, the Commission adopted D.26-10-009 affirming that effective, July 1, 2026, DAC-SASH funding will come solely from PPP funds through December 31, 2030, as a result of AB 1207.¹⁰⁶ Accordingly, Line 14c of Table VII-33 reflects zero GHG funding for 2027. SCE’s 2027 AB 327 allocation of GHG revenues for the DAC-SASH program in the amount of \$4.6 million (*i.e.*, 46 percent of \$10 million) is included in Line 16 in the PPP column on Table VIII-35 and will be recovered from the PPP rate component.

¹⁰⁵ Administrative, IT, and ME&O costs incurred prior to 2022 before switching from GHG allowance revenues to the PPP rate component remained in the GHGRBA.

¹⁰⁶ *Decision Modifying the Disadvantage Communities – Single-Family Solar Homes Program*, in R.25-01-005, p. 5.

1 On June 11, 2026, the Commission adopted D.26-06-006, the final
2 decision *Implementing California Shared Renewables Portfolio* in the GAP Proceeding. Pursuant to AB
3 1207, D.26-06-006 supersedes D.18-06-027 and directs the IOUs to fund DAC-GT and CSGT programs
4 using PPP surcharge collections and update tariffs to reflect the funding change.¹⁰⁷ On July 17, 2026,
5 SCE submitted Advice 5860-E to update its tariff to reflect DAC-GT funding will come from PPP
6 charges.¹⁰⁸

7 In accordance with Resolution E-4999 and D.24-05-065,¹⁰⁹ each
8 Disadvantaged Communities (DAC)-Green Tariff (GT) and Community Solar Green Tariff (CSGT)¹¹⁰
9 program administrator is required to submit annual program budget estimates via advice letter by April
10 1¹¹¹ of each year for the following program year. In its budget advice letter, SCE stated that no funding
11 is needed for 2027 because expected available funding exceeds projected costs through 2026. In
12 accordance with D.26-06-006, Line 14d of Table VII-33 shows a set-aside for 2027 of zero dollars and
13 Line 16 in the PPP column on Table VIII-35 does not include any DAC-GT funding.

14 (3) Updated CCA DAC Programs

15 On June 21, 2018, the Commission issued the DAC Decision adopting
16 three new programs to promote the installation of renewable generation among residential customers in
17 DACs.¹¹² Pursuant to the DAC Decision, CCAs may develop and implement their own DAC-GT and
18 CSGT programs. D.26-06-006 supersedes the DAC Decision and provides that CCAs can now submit a
19 Tier 2 advice letter rather than a Tier 3 advice letter to implement the CCA DAC-GT and CSGT

¹⁰⁷ *Decision Implementing California Shared Renewables Portfolio*, GAP Proceeding, OP 9, COL 12, pp. 22-23.

¹⁰⁸ Advice 5860-E was approved via disposition letter with an effective date of July 17, 2026. SCE updated Preliminary Statement Part PPP, Preliminary Statement Part BB, and Preliminary Statement Part FF.

¹⁰⁹ *Decision Modifying Green Access Program Tariffs and Adopting a Community Renewable Energy Program* was adopted on May 30, 2024, by the Commission. OP 3(i) moved the submission date of the DAC-GT Program Administrators' annual budget advice letters from February 1 to April 1.

¹¹⁰ Per the process noted in SCE's Advice 5382-E, approved on November 15, 2024, all CSGT customers have been transitioned to the DAC-GT Program. SCE has requested to close the applicable balancing account in its 2025 ERRR Review. CPA's CSGT program remains active.

¹¹¹ Advice 5783-E was approved via disposition letter with an effective date of May 1, 2026.

¹¹² As directed by the California Legislature in AB 327 (Perea), Stats. 2013, ch 611.

1 programs. Resolution E-4999 clarified that CCAs shall have access to GHG allowance funds to fund
2 DAC program costs in the same manner as the IOUs and confirmed the process for requesting the set-
3 aside of such funds in each IOU's annual Erra Forecast proceeding. D.26-06-006 confirmed that
4 pursuant to AB 1207, DAC programs are to be funded using PPP surcharge collections and will not alter
5 CCAs access to funding. As such, CCAs' DAC Programs will now be funded through PPP charges in
6 the same manner as the IOU DAC programs.

7 On April 1, 2026, Clean Power Alliance of Southern California (CPA)
8 submitted Advice 0041-E and Supplemental Advice 0041-E-A on April 24, 2026. Table 4 of Advice
9 0041-E-A shows a 2027 fiscal year funding request of \$4.572 million, which is reduced for prior year
10 unspent amounts. In accordance with D.26-06-006, the full request of \$4.572 million will be recovered
11 through PPP funds and is included in Line 16 in the PPP column of Table VIII-35. Line 14e of Table
12 VII-33 reflects zero dollars in GHG funding set-aside in 2027.

13 On April 1, 2026, Lancaster Choice Energy (LCE), Pico Rivera Innovative
14 Municipal Energy (PRIME), and San Jacinto Power (SJP), (collectively, "CalChoice"), submitted an
15 advice letter,¹¹³ demonstrating surplus funding \$0.119 million through program year 2026. As shown in
16 Table 11 of Appendix A of the advice letter, CalChoice requests \$0.925 million in funding for fiscal
17 year 2027. In accordance with D.26-06-006, the full request of \$0.925 million will be recovered through
18 PPP funds and is included in Line 16 in the PPP column of Table VIII-35. Line 14f of Table VII-33
19 reflects zero dollars in GHG funding set-aside in 2027.

20 On August 14, 2025, and September 17, 2025, Orange County Power
21 Authority (OCPA) submitted Advice 13-E/13-E-A, respectively, requesting to establish and implement a
22 DAC-GT program in accordance with the DAC Decision and Resolution E-4999.¹¹⁴ On February 5,
23 2026, the Commission issued Resolution E-5435 approving OCPA's DAC-GT Program. In Resolution
24 E-5435, SCE was directed to include OCPA's estimated budgets for program year 2026 and 2027 in its

¹¹³ LCE Advice 38-E, PRIME Advice 23-E, and SJP Advice 31-E.

¹¹⁴ OCPA's advice letter was submitted and approved prior to D.26-06-006, which modified the process from a Tier 3 to a Tier 2 implementation advice letter.

2027 ERRa Forecast Filing, which are to be funded solely from PPP funds.¹¹⁵ Table 1 of Advice 13-E-A shows the combined 2026 and 2027 program year funding request of \$0.395 million and is included in Line 16 of the PPP column of Table VIII-35.¹¹⁶

3. Transmission Accelerator Revolving Fund

AB 1207 requires SCE to remit five percent of any GHG allowance revenue for the TARF to the State Treasury for the period July 1, 2026, to July 1, 2031. D.24-04-036 directs SCE to remit the five percent to the State Treasury within 15 days of receipt of total allowance revenues from each auction.¹¹⁷ D.26-04-036 further directs SCE to “[r]eport details of the total revenues received and remitted in the reporting period, and use Template D-1, Section 14, as updated in Ordering Paragraph 7, to show forecast and recorded revenues for the Transmission Accelerator Revolving Fund transfers.”¹¹⁸ For 2026, SCE has transferred [REDACTED] million for the August 2026 auction and forecasts transferring \$ [REDACTED] million for the remaining 2026 auction to the TARF, as reflected in Table VII-29. For 2027, SCE forecasts transferring \$28.823 million to the TARF, based on projected revenues from four quarterly auctions that will be held between January 1 through December 31, 2027, as reflected in Table VII-28. Both the 2026 and 2027 forecasted transfers are reflected in Line 14h of Table VII-33.

D.26-04-036 further directs SCE to include in its ERRa Forecast “verification of each transfer in the reporting period.”¹¹⁹ On September 29, 2026, SCE transferred to the California Infrastructure and Economic Development Bank (IBank) \$ [REDACTED] million, five percent of the August 2026 auction revenues reported in Table VII-29. Verification of this transfer can be found in Appendix C, which contains the invoice for the transaction.

¹¹⁵ Resolution E-5435, OP 1 and OP 5.

¹¹⁶ In its ERRa Implementation AL, SCE will update Preliminary Statement Part PPP, DAC-GT Balancing Account, to include a one-way subaccount for OCPA’s DAC-GT Program to track (1) OCPA’s annual funding allocation from public purpose rate recovery based on CPUC-approved budgets, and (2) quarterly transfers of funding to OCPA as approved in SCE’s annual ERRa Forecast proceedings.

¹¹⁷ D.24-04-036, OP 5.

¹¹⁸ *Id.*, OP 6a.

¹¹⁹ *Id.*, OP 6b.

1 In addition, SCE is directed to provide “a summary of total funds transferred and funds
2 encumbered to date.”¹²⁰ SCE requested from IBank a summary of the total funds transferred and
3 encumbered to date. IBank confirmed via written communication that as of October 6, 2026, they were
4 in receipt of \$ [REDACTED] million from SCE for the August 19, 2026 Cap-and-Invest Auction and there are no
5 encumbered funds. Verification of this information can be found in Appendix C, which contains the
6 written communication from IBank.

7 **4. Updated Summary of SCE’s 2027 Proposed GHG Revenue Returns Eligible**
8 **Customers and Residential Customers Through the California Climate Credit**

9 After accounting for administrative and customer outreach costs, Commission-approved
10 set-asides for programmatic costs as described above, and the amount of revenue owed to EITE
11 customers (also on an annual forecast basis), the remaining GHG allowance revenue is distributed as
12 California Climate Credit payments to residential and small business customers, which in 2027 is
13 expected to be \$47.00.

14 A summary of SCE’s 2027 proposed GHG revenue returns is provided in Table VII-32
15 below based on the 2027 GHG cost and revenue forecasts as set forth herein. The proposed 2027
16 allowance revenue returns also reflect a prior period GHG revenue balancing account debit amount of
17 \$4.798 million associated with an estimated December 31, 2026 under-collection in the GHGRBA as
18 discussed and supported in the following section. This true-up amount is subtracted from the 2027
19 forecast allowance auction revenues, and administrative and customer outreach forecast costs are then
20 subtracted from this net amount to derive the net forecast annual allowance revenues to be allocated and
21 returned to eligible customers in 2027.

¹²⁰ *Id.*, OP 6c.

Table VII-32
Updated Summary of SCE's 2027 Proposed GHG Revenue Returns
(\$000)

Line No.	Description	2027 Forecast	
1.	2027 GHG Allowance Revenues	\$ (576,469)	Table VII-27
2.	Franchise Fees and Uncollectibles (FF&U)	\$ (7,158)	Formula
3.	Subtotal 2027 GHG Allowance Revenues	\$ (583,627)	
4.	12/31/26 GHGRBA/Revenue Return True-Up Under / (Over) Collection	\$ 4,798	Table VII-33
5.	Forecast Expenses - 2027		
6.	Non-Utility Statewide Outreach & Education Costs	\$ -	-
7.	GHG Administrative Costs (includes SCE-internal Outreach & Education Costs)	\$ 314	Table VII-30
8.	FF&U	\$ 4	Formula
9.	Subtotal Forecast Expenses	\$ 317	
10.	Total Allowance Revenue Approved for Programatic Use	\$ 27,051	Table VII-33
11.	AB693/SB92 Set Aside for Multi Family Solar Rooftops (SOMAH)	\$ -	Expired
12.	AB693/SB92 Prior Year True up (15% annual cap does not apply)	\$ (1,772)	
13.	AB 327 SCE's DAC-SASH Program	\$ -	Expired
14.	AB 327 SCE's DAC-GT and CSGT Programs	\$ -	Expired
15.	AB 327 CPA's DAC-GT and CSGT Programs	\$ -	Expired
16.	AB 327 Cal Choice's DAC-GT and CSGT Programs	\$ -	Expired
17.	CEOP Pilot	\$ -	Expired
18.	State Transmission Accelerator	\$ 28,823	
19.	Subtotal Set Asides	\$ 27,051	
20.	Net GHG Revenues Available for Return (Lines 3 + 4 + 9 + 19)	\$ (551,460)	Formula
21.	GHG Revenue Amount Returned to Eligible Customers		
22.	EITE Customers Return	\$ 47,831	Table VII-33
23.	Small Business Customers Volumetric Return	\$ -	Expired
24.	Residential Customers Volumetric Return	\$ -	Expired
25.	Subtotal EITE/Volumetric Returns	\$ 47,831	
26.	Total Revenues Available for Residential and Small Commercial CA Climate Credit (Line 20 + Line 25)	\$ (503,629)	Formula
27.	Estimated Number of Households and Small Businesses Eligible for 2027 CA Climate Credit	5,315,824	Table VII-33
28.	Estimated 2027 Semi-Annual Residential CA Climate Credit ((-Line 27 / Line 26) / 2)	\$ 47.00	Formula

1 **5. Updated Historical Allowance Revenue Receipts and Customer Returns**

2 Table VII-33 below provides the information for Template D-1 “Annual Allowance
3 Revenue Receipts and Customer Returns” pursuant to the GHG Phase 2 Decision and presents an
4 accounting of the recorded GHGRBA activity through August 31, 2026, and estimated activity for
5 September 1, 2026, through December 31, 2026.¹²¹ This reconciliation produces an over-disbursement
6 due to the difference in forecast and actual auction allowance revenues and allowance revenue returns.
7 This forecast shortfall of 2026 allowance revenue in the amount of \$4.798 million is subtracted from the
8 forecast year 2027 auction allowance revenues to determine the net revenue amount available for
9 disbursement to eligible customers in 2027. Based on the updated costs and revenues set forth herein,
10 SCE’s proposed 2027 residential and small business California Climate Credit is \$47.00 to be
11 distributed twice in 2027 on residential and small business customer bills.

¹²¹ Beginning in 2027, Template D-1 reflects updates authorized in D.26-04-036 in R.25-07-013.

Table VII-33
Updated Annual Allowance Revenue Receipts and Customer Returns (Template D-1)

Line	Description	2023		2024 ¹		2025		2026		2027 ²	
		Forecast	Recorded	Forecast	Recorded	Forecast	Recorded	Forecast	Recorded	Forecast	Recorded
1	Proxy GHG Price (\$/MT)	\$	30.26	\$	32.42	\$	39.36	\$	34.61	\$	27.59
2	Allocated Allowances (MT)		24,357,709		24,357,709		21,635,309		22,316,439		21,635,309
3	Revenues (\$)										
4	Prior Balance	\$	(82,396,932)	\$	(72,881,893)	\$	(45,488,229)	\$	(15,818,094)	\$	151,727,050
5	Allowance Revenue	\$	(737,664,274)	\$	(789,791,023)	\$	(932,107,540)	\$	(819,524,252)	\$	(635,585,209)
6	Interest	\$	-	\$	1,600,502	\$	-	\$	1,276,381	\$	9,325,566
7	Franchise Fees and Uncollectibles	\$	(8,243,853)	\$	(8,841,203)	\$	(10,425,356)	\$	(10,651,200)	\$	(7,900,180)
8	Subtotal Revenues	\$	(827,705,059)	\$	(869,621,620)	\$	(988,021,125)	\$	(844,718,166)	\$	(481,832,774)
9	Expenses (\$)										
10	Outreach and Administrative Expenses (from Template D-3)	\$	325,000	\$	306,328	\$	325,000	\$	867,816	\$	455,110
11	Franchise Fees and Uncollectibles	\$	3,635	\$	1,460	\$	3,635	\$	10,022	\$	5,156
12	Interest	\$	-	\$	-	\$	-	\$	-	\$	-
13	Subtotal Expenses	\$	328,635	\$	317,788	\$	328,635	\$	877,838	\$	460,266
14	Total Allowance Revenue Approved for Programmatic Use (\$)										
14a	Sum of Lines 14a through 14d	\$	54,178,466	\$	54,171,716	\$	32,507,426	\$	32,588,205	\$	55,935,630
14b	AB093-S092 Set Aside for Multi-Family Solar Rooftops (GOMAM)	\$	46,527,856	\$	46,527,856	\$	46,527,856	\$	46,527,856	\$	46,527,856
14c	AB093-S092 Prior Year True-up (15% annual cap does not apply) ³	\$	2,182,860	\$	2,182,860	\$	(11,592,218)	\$	3,680,858	\$	3,327,997
14d	AB 327 SCEE's DAC-SASRI Program	\$	4,660,000	\$	4,660,000	\$	4,660,000	\$	4,660,000	\$	4,660,000
14e	AB 327 SCEE's DAC-GT and CSGT Programs	\$	-	\$	-	\$	-	\$	-	\$	-
14f	AB 327 CPAN's DAC-GT and CSGT Programs	\$	315,420	\$	311,000	\$	26,769	\$	1,126,916	\$	1,901,656
14g	CEOP Pilot	\$	154,349	\$	151,000	\$	25,029	\$	-	\$	-
14h	State Transmission Accelerator	\$	400,000	\$	400,000	\$	-	\$	-	\$	-
15	Net GHG Revenues (\$) (Line 8 + Line 13 + Line 14)	\$	(773,197,939)	\$	(815,131,116)	\$	(955,105,054)	\$	(641,623,944)	\$	(425,436,877)
16	GHG Revenues to be Distributed in Future Years (\$)										
17	Net GHG Revenues Available for Customers in Forecast Year (\$)										
17a	(Lines 15 + Line 16)	\$	(773,197,939)	\$	(815,131,116)	\$	(955,105,054)	\$	(641,623,944)	\$	(425,436,877)
18	GHG Revenue Returned to Eligible EITE Customers (\$)										
19	EITE Customer Return	\$	40,416,282	\$	58,941,176	\$	58,834,465	\$	58,877,766	\$	58,481,761
20	Small Business Volumetric Return	\$	-	\$	20,791	\$	-	\$	1,000	\$	-
21	Residential Volumetric Return	\$	-	\$	-	\$	-	\$	-	\$	-
22	Subtotal EITE + Volumetric Returns	\$	40,416,282	\$	58,961,967	\$	58,834,465	\$	59,878,766	\$	58,481,761
23	Small Annual Climate Credit										
24	Number of Eligible Residential Insulated Households		3,034,387		3,034,387		3,415,849		3,415,849		3,335,867
25	Number of Eligible Residential Uninsulated Households		1,587,218		1,587,218		1,269,347		1,387,360		1,387,360
26	Number of Eligible Small Business Customers		538,528		538,528		541,982		477,066		477,066
27	Total Customers Eligible for Climate Credit		5,160,130		5,160,130		5,227,178		5,200,294		5,200,294
28	Per Customer Small Annual Climate Credit										
28a	(0.5 x (Line 17 + 22) + Line 27)	\$	71	\$	71	\$	86	\$	86	\$	56
29	Total Revenue Distributed for the Climate Credit (\$)										
29a	(2 x Line 27 x Line 28)	\$	732,281,696	\$	740,351,055	\$	896,270,589	\$	904,872,140	\$	592,253,316
30	Revenue Balance (\$)										
30a	(Lines 17 + Line 22 + Line 29)	\$	-	\$	(15,818,094)	\$	-	\$	151,727,050	\$	-

1/ Recorded through August 31, 2026 plus estimated from September 1, 2026 through December 31, 2026.

2/ SCE made an inadvertent error and made changes to Line 18 and Line 11 to reflect the broadcast of expirations and franchise fees and uncollectibles.

3/ SCE is including the 92MWH Program Funding True-up for 2023 outlined in addendum 17524, which was approved by the Commission on August 27, 2026.

4/ Beginning in 2027, Template D-1 reflects updates authorized in D.26-04-036 in R.24-07-01.

VIII.

UPDATED 2027 FORECAST REVENUE REQUIREMENT AND RATEMAKING PROPOSAL

A. Introduction

This chapter presents SCE's requested 2027 ERRA Forecast proceeding revenue requirement of \$4.510 billion, as shown on Line No. 22 of Table VIII-34. This 2027 ERRA Forecast revenue requirement includes 2027 GHG allowance revenues to be returned to eligible customers in 2027 as supported in Chapter VIII herein.

Table VIII-34
Updated Estimated 2027 ERRA Forecast Proceeding Revenue Requirement
(\$000)

Line No.	Description	Estimated 2027 Revenue Requirement
1.	<u>Generation Service</u>	
2.	Fuel and Purchased Power Forecast (includes GHG costs)	
3.	ERRA BA-related	\$ 2,322,147
4.	PABA-related	\$ 2,182,038
5.	GTSR-related	\$ 4,710
6.	Estimated 2026 YE ERRA BA Balance	\$ (1,288,988)
7.	Estimated 2026 YE PABA Balance	\$ 1,438,745
8.	Estimated 2026 YE ESMA Balance (net) 1/	\$ 144
9.	TOTAL ERRA PROCEEDING GENERATION SERVICE	\$ 4,658,796
10.	<u>Delivery Service</u>	
11.	New System Generation Fuel and Purchased Power Forecast	\$ 352,716
12.	Estimated 2026 YE NSGBA Balance	\$ 9,669
13.	MCAM Fuel and Purchased Power Forecast	\$ 3,797
14.	Estimated 2026 YE MCAMBA Balance	\$ 967
15.	Spent Nuclear Fuel Storage Forecast	\$ 5,433
16.	BRBBA-D Fuel and Purchased Power Forecast	\$ (2,459)
17.	GHG Allowance Revenues	\$ (551,460)
18.	PPP Fuel and Purchased Power Forecast 2/	\$ 33,148
19.	Estimated 2026 YE TMNBCBA Balance	\$ 2,607
20.	Estimated 2026 YE BMNBCBA Balance	\$ (2,927)
21.	TOTAL ERRA PROCEEDING DELIVERY SERVICE	\$ (148,509)
22.	TOTAL ERRA PROCEEDING REVENUE REQUIREMENT	\$ 4,510,287

^{1/} Estimated generator refunds are net of litigation costs.

^{2/} Includes TMNBC, BMNBC, LCR-PPP and DAC-GT/CSGT PPPC amounts.

^{3/} Excludes the revenue requirement associated with the 2025 General Rate Case Revenue Requirement Memorandum Account (GRCRMMA).

1 SCE will include additional recorded actuals in its estimates of the 2026 year-end balances when
2 calculating its final 2027 ERRRA Forecast revenue requirement that is ultimately implemented in rates.
3 The support for these updates will be included in the implementation advice letter submitted in
4 compliance with a final Commission decision in this proceeding.¹²²

5 **B. Updated Estimated 2027 Forecast Fuel and Purchased Power Revenue Requirement**

6 As shown in Table VIII-35 below, SCE's fuel and purchased power revenue requirement is
7 recorded in various balancing accounts. As shown on Line No. 19 of Table VIII-35, SCE's requested
8 2027 forecast fuel and purchased power cost revenue requirement is \$4.902 billion.¹²³ This amount
9 includes \$64.035 million for FF&U expense and municipal surcharges.¹²⁴

¹²² Due to the timing of SCE's rate change and the date that factors must be provided to billing, the final balances implemented in rates to start on January 1, 2027, may consist of recorded actuals through November 2026 and a forecast of December 2026 activity. If the rate change is implemented after January 1, 2027, the final balances may include all recorded actuals and no estimated amounts.

¹²³ Amounts included in Line No. 19 of Table VIII-35 for DACCSGTBA are not included in the revenue requirement used to calculate rates.

¹²⁴ Pursuant to D.25-09-030, which approved Phase 1 of SCE's 2025 GRC, and Advice 5663-E, SCE is using its adopted 2026 FF&U factor of 0.987736. The municipal surcharge amount shown on Line No. 18 of Table VIII-35 is the amount of the municipal surcharges (franchise fees) that SCE estimates it will pay associated with the WF Fund NBC revenue requirement in 2027. The Uncollectibles Factor will be updated for 2027 in the implementation advice letter.

Table VIII-35
Updated 2027 Forecast Fuel & Purchased Power by Balancing Account
(\$000)

Line No.	Category	ERRA BA ¹	PABA ¹	GTSRBA	Subtotal	NSGBA	MCAMBA	TMINBCBA	BMNBCBA	Delivery Service PP ²	BRBA-D ³	DACCSGTBA	NDC	Subtotal	Grand Total
1.	UOG														
2.	Renewables and QE														
3.	GTSR Contracts														
4.	Conventional Contracts														
5.	ACES														
6.	GAM Portfolio CHP														
7.	LCR														
8.	Direct GHG Costs														
9.	Hedging Costs														
10.	ISO Costs														
11.	Load Procurement Costs														
12.	RA Sales														
13.	RPS Sales														
14.	Market Revenues														
15.	Concession ⁴														
16.	Other ⁵														
17.	Subtotal	\$ 2,289,754	\$ 2,155,278	\$ 4,653	\$ 4,449,684	\$ 348,390	\$ 3,751	\$ 17,113	\$ 2,306	\$ 13,322	\$ (2,429)	\$ 695	\$ 5,167	\$ 388,514	\$ 4,838,199
18.	FF&U ⁶	\$ 32,193	\$ 26,761	\$ 58	\$ 59,211	\$ 4,326	\$ 47	\$ 212	\$ 29	\$ 165	\$ (30)	\$ 9	\$ 67	\$ 4,824	\$ 64,035
19.	Grand Total	\$ 2,322,147	\$ 2,182,038	\$ 4,710	\$ 4,508,896	\$ 352,716	\$ 3,797	\$ 17,325	\$ 2,335	\$ 13,488	\$ (2,459)	\$ 703	\$ 5,433	\$ 393,338	\$ 4,902,234

Areas shaded in grey are confidential per D 06-06-066, Naimi section V.C.

¹ ERRA BA and PABA sub-totals only reflect the forecast fuel and purchased power costs.

² Includes costs that are recorded to the PPP sub-account of the Local Capacity Requirements Products Balancing Account (LCRPBA) and the 2027 DAC-GT/CSGT finding that is recorded via the PPPC (shown in the "Other" row).

³ Includes costs that are recorded directly to BRBA-D (e.g., DRAM and PRP) and the Distribution sub-account of the LCRPBA.

⁴ Concession costs include Gas Transportation and Storage Costs, Collateral Carrying Costs and GHG Carrying Costs.

⁵ Other costs include the subscription fee forecast to be recorded in the ERRA BA, the forecast 2027 administrative costs related to SCE functioning as the CPE for local RA, the audit expenses forecast to be recorded in the TMINBCBA, and the CARB administrative fee payments and Energy Imbalance Market Body of State Regulator (EIM BOSR) costs in the BRBA-D.

⁶ ERRA BA FF&U includes the Municipal Surcharge (Franchise Fees).

⁷ Pursuant to D 25-09-030, Phase 1 of SCE's 2025 GRC, and Advice 5663-E, SCE is using its adopted 2026 FF&U Factor of 0.987736.

1 **1. Updated Fuel Expense**

2 As shown on Line No. 9 in Table VIII-36 below, SCE has total 2027 forecast fuel costs
3 of \$52.882 million.

Table VIII-36
Updated 2027 Forecast Fuel Expenses
(\$000)

Line No.	Component	Amount
1.	Nuclear - Palo Verde	
2.	Gas	
3.	Mountainview	
4.	Catalina	
5.	Diesel	\$ 7,913
6.	Propane	\$ 1,265
7.	Catalina Subtotal	\$ 9,178
8.	Fuel Inventory Carrying Cost	
9.	TOTAL ^{1/}	\$ 52,882
1/ This amount excludes a portion of common costs allocated to the ERRA, PABA and NSGBA.		

Areas shaded in gray are confidential per D.06-06-066, Matrix section V.C.

4 The 2027 forecast PVNGS, Mountainview, and Catalina fuel costs are supported in
5 Chapter IV. The forecast of fuel inventory carrying costs associated with nuclear, natural gas, and diesel
6 fuel inventories are supported in Chapter VI.

7 **2. Updated Forecast Purchased Power Expense**

8 As shown on Line No. 16 in Table VIII-37 below, SCE estimates its total 2027 forecast
9 purchased power costs to be \$4.773 billion, as supported in Chapter IV. Collateral and carrying costs
10 are supported in Chapters V and VI.

Table VIII-37
Updated 2027 Forecast Purchased Power Expense
(\$000)

Line No.	Category	Grand Total
1. UOG ¹		
2. Renewables and QF		
3. GTSR Contracts		
4. Conventional Contracts		
5. ACES		
6. CAM Portfolio CHP		
7. LCR		
8. Direct GHG Costs		
9. Hedging Costs		
10. ISO Costs		
11. Load Procurement Costs		
12. RA Sales		
13. RPS Sales		
14. Market Revenues		
15. Common ²		
16. Total ³		\$ 4,772,764

Areas shaded in gray are confidential per D.06-06-066, Matrix section V.C.

¹ UOG costs exclude fuel costs, which comprise Palos Verdes nuclear fuel costs, Catalina diesel and propane fuel costs, Mountainview fuel costs and fuel carrying costs. These costs are itemized in Table VIII-36.

² Common costs include collateral and GHG carrying costs.

³ The total amount excludes FF&U.

C. Updated Estimated 2027 Forecast Generation Service Revenue Requirement

As shown on Line No. 9 of Table VIII-34, SCE requests a 2027 generation service revenue requirement of \$4.659 billion (including FF&U). This revenue requirement is a consolidation of forecast 2027 ERRA BA, PABA and GTSR F&PP expenses, estimated December 31, 2026 balances in the ERRA BA and PABA, and estimated net generator refunds¹²⁵ stemming from electricity overcharges to SCE during the 2000-2001 California Energy Crisis.

¹²⁵ The forecast estimated net generator refunds are net of forecast associated litigation costs, which are recorded in the LCTA.

1 **1. Updated 2027 Forecast Fuel and Purchased Power Costs**

2 The forecast generation service costs in the 2027 F&PP forecast result from costs and
3 revenues that are categorized into three “portfolios”: ERRA BA portfolio, PABA portfolio, and the
4 GTSR portfolio.

5 a) ERRA BA-Related F&PP Costs

6 As shown on Line No. 3 of Table VIII-34, the forecast of the 2027 fuel and
7 purchased power costs that will record to the ERRA BA is \$2.322 billion (including FF&U). This
8 forecast includes the estimated costs associated with SCE’s wholesale short-term market purchases (*i.e.*,
9 the costs of meeting remaining bundled service customers’ full energy and ancillary services
10 requirements through the CAISO market with contract terms less than one year in duration) and the fuel
11 and purchased power costs of any contracted resources that are not eligible for recovery in the PABA or
12 the NSGBA (or other balancing account).

13 The 2027 ERRA BA-related F&PP forecast includes estimates of SCE’s 2027
14 F&PP-related subscription fees. As shown on Line No. 7 of Table IV-22, SCE estimates its total 2027
15 F&PP-related subscription fees to be \$1.047 million.

16 b) PABA-Related F&PP Costs

17 As shown on Line No. 4 of Table VIII-34, the forecast of the 2027 fuel and
18 purchased power costs that will record to the PABA is \$2.182 billion (including FF&U). This forecast
19 includes the estimated costs associated with SCE’s PCIA- and CTC-eligible resources.¹²⁶ Eligible
20 resources include SCE’s UOG facilities and power purchase contracts in excess of one year in length
21 and exclude resources eligible for CAM (or another non-PCIA related cost recovery mechanism) and
22 power purchase contracts less than one year in length.¹²⁷

¹²⁶ This includes the bundled service customers’ share of the system reliability procurement authorized pursuant to D.19-11-016, which is recovered via the 2019 subaccount of the PABA. *See also* Advice 4831-E and Resolution E-5240.

¹²⁷ On June 24, 2021, the Commission adopted D.21-06-035, which addresses the mid-term reliability needs of the electricity system within CAISO’s operating system by requiring at least 11,500 MW of additional NQC to be procured by all LSEs subject to the Commission’s IRP authority. Load migration for existing IOU

1 c) GTSR-Related F&PP Costs

2 As shown on Line No. 5 of Table VIII-34, the forecast costs that will record to the
3 GTSRBA is \$4.710 million (including FF&U). This forecast includes the estimated costs associated
4 with SCE's GTSR-eligible resources.

5 **2. Updated Estimated December 31, 2026 Generation-Related Balancing Account**
6 **Balances**

7 The estimates of the 2026 year-end generation-related balances to be recovered from
8 customers in 2027 are included in the ERRA BA and the PABA. Each account is described in more
9 detail below. As discussed above, consistent with past practice, SCE's estimates of the 2026 year-end
10 balances are based on the forecast costs adopted in SCE's 2026 ERRA Forecast proceeding in D.24-12-
11 039 except that January through September 2026 have been updated with recorded actuals and October
12 through December 2026 incorporate updated forward market prices as of October 2, 2026.

13 a) ERRA BA

14 The ERRA BA was established in D.02-10-062, effective January 1, 2003. The
15 purpose of the ERRA BA is to record the difference between ERRA BA-related revenue and SCE's
16 ERRA BA-related fuel and purchased power expenses. In Advice 3914-E, SCE modified the ERRA BA
17 to record only the costs associated with SCE's wholesale short-term market purchases (*i.e.*, the costs of
18 meeting remaining bundled service customers' full energy and ancillary services requirements through
19 the CAISO market with contract terms of less than one year in duration), the fuel and purchased power
20 costs of any contracted resources that are not eligible for recovery in the PABA or the NSGBA (or any
21 other balancing account), and the actual retained RPS and RA value from SCE's CTC- and PCIA-

customers is handled by allocating the PCIA-eligible costs to the 2021 resource subaccount of the PABA, in alignment with the date of D.21-06-035. *See also* Advice 4589-E. On February 28, 2023, the Commission adopted D.23-02-040, which ordered supplemental mid-term reliability procurement (2026-2027) of a total of 4,000 MW of NQC in addition to the 11,500 MW ordered previously in D.21-06-035. *See also* Advice 5019-E. Costs and revenues associated with contracts executed in accordance with D.23-02-040 are recovered via the 2023 resource subaccount of the PABA. On February 6, 2026, the Commission adopted D.26-02-057, which orders additional reliability procurement of a total of 6,000 MW of NQC that is required to come online over the 2030-2032 period. *See also* Advice 5778-E. Costs and revenues associated with contracts executed in accordance with D.26-02-057 are recovered via the 2026 resource subaccount of the PABA.

1 eligible resources (calculated using the Commission-provided Forecast and Final RPS and RA Adders)
2 used to meet bundled service customer requirements. The responsibility for the costs recorded in the
3 ERRA BA lies solely with then-current bundled service customers.

4 As shown in Table 1 of Appendix A and on Line No. 6 of Table VIII-34, SCE
5 estimates that the ERRA BA will be over-collected by \$1,288.988 million (including FF&U) as of
6 December 31, 2026, which is the result of the lower-than-forecast power and gas prices relative to the
7 2026 ERRA Forecast used to establish current rates as well as the true-up of Actual Retained RPS using
8 the 2026 Final RPS Adder.

9 In order to estimate the year-end ERRA BA balance, SCE used recorded amounts
10 through September 30, 2026, plus a forecast of the activity SCE expects to record in the ERRA BA
11 during October through December 2026.

12 b) PABA

13 The PABA was established pursuant to D.18-10-019, effective January 1, 2019.
14 The purpose of the PABA is to record, by subaccount, the above-market costs,¹²⁸ market revenues,
15 actual retained RA and RPS values (as calculated using the Commission-provided Forecast and Final
16 RA and RPS Adders, as applicable), and billed customer revenues associated with SCE's CTC- and
17 PCIA-eligible resources.

18 As shown in Table 2 of Appendix A and on Line No. 7 of Table VIII-34, SCE
19 estimates that the balance in the PABA will be an under-collection of \$1,438.745 million (including
20 FF&U) as of December 31, 2026. The under-collection is largely attributed to the true-up associated
21 with the application of the 2026 Final RPS Adder coupled with lower-than-forecast power prices, which
22 result in lower-than-forecast REC and CAISO market revenues recording to the PABA. In order to
23 estimate the year-end PABA balance, SCE used recorded amounts from January 1, 2026, through

¹²⁸ Pursuant to D.18-10-019 and D.19-10-001, 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. See D.18-10-019, OP 1 and p. 42.

1 September 30, 2026, plus a forecast of the activity that SCE expects to record in the PABA during
2 October through December 2026.

3 (1) Transfer of the Mohave SO₂ Allowance Revolving Fund Memorandum
4 Account

5 The Mohave SO₂ Allowance Revolving Fund Memorandum Account
6 (MSARFMA) was established in 2013 pursuant to D.13-02-004.¹²⁹ The purpose of the MSARFMA is
7 to record the net proceeds from the sale of sulfur dioxide (SO₂) emission allowances rendered surplus by
8 the closure of the Mohave Generating Station and to maintain and account for the revolving fund
9 resulting from such sales and any use of the net sales proceeds by renewable energy projects as allowed
10 under D.13-02-004.

11 Consistent with D.13-02-004, the termination date of this revolving fund is
12 the later of December 31, 2026, or upon the return in the MSARFMA of the last funds provided from
13 the MSARFMA for project use (unless the MSARFMA is terminated or altered earlier by the
14 Commission, which has not happened).¹³⁰ In accordance with SCE's Preliminary Statement Part N.46,
15 all funds attributable to SCE's sale of surplus Mohave SO₂ allowances prior to January 1, 2027, must be
16 returned to customers through rates no later than 15 months after the termination of the revolving fund.
17 The revolving fund is scheduled to terminate on the later of December 31, 2026, or upon the return into
18 the MSARFMA of the last funds provided to projects.

19 Currently, the MSARFMA Preliminary Statement (Part N.46) reflects
20 disposition through the ERRA BA. When the MSARFMA was initially established in 2013, PABA did
21 not exist and generally all fuel and purchased power costs were recovered solely via the ERRA BA.
22 Accordingly, generation-related balances were generally disposed through the ERRA BA, and the
23 MSARFMA Preliminary Statement reflected that framework. Because the net proceeds from the sale of
24 Mohave SO₂ emission allowances have remained in the revolving fund, the MSARFMA Preliminary

¹²⁹ D.13-02-004, OP 9. See Advice 2884-E. Advice 2884-E has an effective date of May 15, 2013.

¹³⁰ D.13-02-004, OP 12.

Statement has not been updated to reflect subsequent changes in generation-related cost recovery mechanisms.

With the establishment of PABA, SCE finds that the disposition through the One-Time Refunds/Costs Subaccount of PABA is now the more appropriate ratemaking treatment because it would more equitably distribute the credits between both bundled and unbundled customers.

Therefore, SCE requests Commission authorization, via an Ordering Paragraph in the Final Decision to this proceeding, to update its MSARFMA Preliminary Statement to reflect the disposition of any remaining MSARFMA balance through the One-Time Refunds/Costs Subaccount of the PABA instead of the ERRA BA.¹³¹ Upon receiving Commission approval, SCE would effectuate the change to the MSARFMA Preliminary Statement as part of its 2027 ERRA Forecast Implementation Advice Letter.

As explained in SCE's March 2026 annual MSARF status report to Energy Division, to-date the MSARF funds have remained unused, with no renewable energy projects using or seeking to use any of the MSARF money.¹³² SCE is not proposing to transfer the actual balance until 2027,¹³³ after it has determined the final amount remaining in the revolving fund and has obtained separate Commission approval through a Tier 2 Advice Letter to be filed in 2027, pursuant to D.13-02-004.¹³⁴

c) Estimated Energy Settlement Refunds and Litigation Costs

SCE is pursuing refunds from generators who overcharged SCE (and the other California IOUs) for electricity during the 2000-2001 California Energy Crisis. As shown in Table 3 of

¹³¹ Disposition (Section e) of Preliminary Statement Part N.46, Sheet 57.

¹³² As of March 2026, a cumulative total of 186,139 SO₂ allowances have been sold, which resulted in \$3.524 million in proceeds (not including any interest that has accumulated).

¹³³ As explained in SCE's initial testimony (SCE-01, p. 118), SCE had erroneously included a transfer of approximately \$4.678 million in year-end forecast for 2026 and was unable to remove the amount due to the timing of the discovery of the issue. The transfer has been removed in this updated 2026 year-end forecast.

¹³⁴ D.13-02-004, OP 13.

Appendix A, SCE estimates a December 31, 2026 balance of \$0.000 million (including FF&U) in the ESMA.

Also included in Table 3 of Appendix A is the Litigation Costs Tracking Account (LCTA). In accordance with Resolution E-3894, SCE is required to maintain an LCTA within the ESMA to track: 1) litigation costs that are “set-aside” in the FERC investigation settlement agreements; and 2) actual litigation costs incurred by SCE. As shown in Table 3 of Appendix A, SCE estimates a December 31, 2026 balance of \$0.144 million (including FF&U) in the LCTA. Combining the ESMA and LCTA estimated December 31, 2026 ending balances results in an under-collection of \$0.144 million (including FF&U) to be collected from customers, as shown on Line No. 8 of Table VIII-34.

D. Updated 2027 Forecast Delivery Service Revenue Requirement

As shown on Line No. 21 of Table VIII-34 above, SCE requests a 2027 forecast delivery service revenue requirement of -\$148.509 million. This amount is a consolidation of 2027 New System Generation forecast costs (including CPE-related costs) and the estimated December 31, 2026 balance in the NSGBA; 2027 System Reliability MCAM-related forecast costs pursuant to D.19-11-016 and the estimated December 31, 2026 balance in the MCAMBA; 2027 Tree Mortality contract forecast costs and the estimated December 31, 2026 balance in the TMNBCBA; 2027 BioMAT contract forecast costs and the estimated December 31, 2026 balance in the BMNBCBA; the 2027 forecast spent nuclear fuel storage revenue requirement; 2027 BRRBA-Distribution fuel and purchased power forecast costs;¹³⁵ and, the estimated GHG allowance revenues to be returned to eligible customers in 2027.

¹³⁵ Pursuant to the California Global Warming Solutions Act of 2006 (AB 32), the CARB is authorized to adopt a schedule of fees to be paid annually by, among other emitting resources, the electric utilities to cover the State’s cost of implementing AB 32. SCE’s payments to CARB are mandated by law, with the payment amounts prescribed by annual invoices received per facility. For electricity generators, fees are based on the amount of MWh of electricity generated or imported (including transmissions losses) multiplied by the Electricity Fee Rate (EFR). The EFR is calculated by multiplying the common carbon cost by the emission factor of the generating facility in the case of in-state generation and specified imports, or by the default emissions factor for unspecified sources in the case of unspecified imports. These fees are used to fund costs directly related to the development, administration, and implementation of AB 32 programs. Payment amounts are calculated by CARB based on validated emissions and fuels data for prior years on a dollar per metric ton of CO₂ basis. For 2027, SCE is forecasting the administrative payment fees to the CARB to be \$0.723 million, which are recovered via distribution rates and recorded in BRRBA-D.

1 Additionally, as described in Section VII.A and C, pursuant to AB 1207, SCE discontinued the use of
2 GHG funding for Clean Energy Programs. For certain programs, funding transitioned to recovery
3 through the PPP Charge and is now reflected in the forecast delivery service revenue requirement.

4 **1. Forecast New System Generation Net Capacity CAM-Related Costs**

5 a) Introduction

6 In D.06-07-029, the Commission adopted a CAM to allocate the benefits and
7 costs of new generation to all benefiting customers in an IOU's service area for up to ten years. D.06-
8 07-029 required utilities to make a selection at the time they seek contract approval whether or not they
9 intend that the CAM should apply to the contract.¹³⁶ In addition, the Commission either adopts or
10 rejects the utility's request in the decision approving or rejecting the new generation contract.
11 Consistent with D.06-07-029, SCE established the non-bypassable New System Generation rate
12 component and associated NSGBA to recover the net costs of the new generation resources from all
13 benefiting customers, including bundled service customers, DA, and CCA customers.

14 In addition, D.10-12-035 adopted the QF and CHP Program Settlement
15 Agreement, which, among other things, allows SCE to purchase CHP generation on behalf of DA
16 customers' ESPs and CCAs. The Commission allowed the IOUs to recover "net capacity costs" from all
17 bundled service customers, DA, and CCA customers through the CAM.

18 After D.06-07-029 and D.10-12-035, SB 695 enacted and expressly required the
19 Commission "to ensure, under certain conditions, the net capacity costs of the specified generation
20 resources are allocated on a fully non-bypassable basis to bundled service customers, as well as
21 departing load and DA and CCA customers." As a result of SB 695, the Commission issued D.11-05-
22 005 modifying the new generation and long-term contract CAM previously adopted in D.06-07-029.
23 D.11-05-005 eliminates the "election" process and changes the duration of CAM treatment from a 10-

¹³⁶ D.06-07-029, CoL 6, p. 60.

1 year period to match the duration of the underlying PPA.¹³⁷ D.11-05-005 also requires the Commission
2 to determine whether CAM is applicable.¹³⁸

3 On June 11, 2020, the Commission adopted D.20-06-002, which, in part,
4 identifies SCE as the CPE for its respective distribution service area related to the central procurement
5 of multi-year local RA procurement beginning with the 2023 compliance year. The decision adopts
6 CAM as the cost recovery mechanism for the CPE procurement of local RA and orders SCE to establish
7 a Centralized Local Procurement Balancing Account as a subaccount of the NGSBA in order to
8 facilitate the cost recovery process.¹³⁹ On August 14, 2020, SCE submitted Advice 4273-E/E-A to
9 establish the Centralized Local Procurement Subaccount (CLPSA) in SCE's existing NSGBA to
10 facilitate cost recovery using the CAM.¹⁴⁰ D.20-06-002 (OP 16) also found that the administrative costs
11 incurred by the CPE in serving the central procurement function shall be recoverable under the CAM,
12 and OP 17 of D.20-06-002 requires that the CPE submit its administrative costs associated with the CPE
13 for review as part of SCE's annual ERRA Review and Forecast proceedings. SCE's forecast of its CPE
14 costs is discussed in Exhibit SCE-06.

15 In 2021, the Commission adopted three decisions that authorize CAM recovery
16 via the NSGBA to address summer emergency reliability. On February 11, 2021, the Commission
17 adopted D.21-02-028, which directs and authorizes the IOUs to contract for capacity that is available to
18 serve peak and net peak demand in the summers of 2022 and/or 2023, and specifies that contracts
19 procured pursuant to this decision are also recovered under the CAM.¹⁴¹ In addition, D.21-03-056
20 authorizes the IOUs to conduct additional procurement to meet the incremental 2.5 percent portion of an
21 "effective" 17.5 percent planning reserve margin for the summers of 2022 and 2023 with cost recovery

¹³⁷ D.11-05-005 also modified D.06-07-029 to allow CAM treatment for certain UOG.

¹³⁸ D.11-05-005, pp. 6-7.

¹³⁹ D.20-06-002, OP 17.

¹⁴⁰ Advice 4273-E/E-A was approved by the Commission's Energy Division on January 5, 2021, with a September 13, 2020 effective date.

¹⁴¹ See D.21-02-028, p. 12 and OP 1, and Advice 4373-E.

1 from all benefitting customers pursuant to the CAM,¹⁴² and provides guidance on the treatment of new
2 and existing import allocation rights and the use of excess RA to meet those procurement targets.¹⁴³ On
3 December 2, 2021, the Commission adopted D.21-12-015, its “Phase 2” decision directing the IOUs to
4 take actions to prepare for potential extreme weather in the summers of 2022 and 2023. Specifically,
5 D.21-12-015 directed the IOUs to endeavor to achieve an effective 20 percent to 22.5 percent planning
6 reserve margin for the months of concern and ordered that net costs shall be passed through to all
7 benefitting customers consistent with the CAM.¹⁴⁴

8 On June 26, 2025, the Commission adopted D.25-06-048, which extended the use
9 of effective PRM procurement targets of 1,260-2,300 MW for the June-October months¹⁴⁵ for the 2026
10 and 2027 RA compliance years, with such costs recovered via the CAM.

11 b) 2027 CAM Eligible Costs

12 Table VIII-38 shows the contracts and UOG resources for which the Commission
13 has authorized CAM cost recovery (*i.e.*, the net costs are to be recovered from all benefitting customers).

¹⁴² See also Advice 4546-E, Advice 4556-E, 4619-E, 4680-E, 4767-E, and 4787-E.

¹⁴³ See D.21-03-056 Attachment, 1, p. 22, and Advice 4477-E.

¹⁴⁴ See D.21-12-015, OP 70.

¹⁴⁵ See D.25-06-048, OP 6.

Table VIII-38
CAM Applicable Resources

SOUTHERN CALIFORNIA EDISON COMPANY CAM Applicable Resources	
	CAM Authorization
All Customers: 1) pay their share of the net costs (i.e., total costs less value of energy and ancillary services) and, 2) receive RA capacity benefits	
The Procter & Gamble Paper Products Company	AL 3882-E/D.10-12-035
LLC/Orni 34, LCC, Silverstrand Grid, LLC,	AL 4002-E/Res. E-5033
Barre Peaker/Center Peaker /Grapeland Peaker/Mira Loma Peaker	D.09-03-031
McGrath Peaker	D.14-06-043
AES Huntington Beach Energy, LLC/AES Alamitos Energy, LLC/Stanton Energy Reliability Center, LLC/AES ES Alamitos, LLC	D.15-11-041
EGT Grapeland/EGT Center/Mira Loma A/Mira Loma B	D.18-06-009
Strata Saticoy, LLC	D.19-12-055
Painter Energy Storage, LLC/Goleta Energy Storage, LLC	Resolution E-5033
Titanium 1	
Qualifying Facilities and Combined Heat and Power:	D.10-12-035
Qualifying Facility PURPA Contract (all CHP QFs up to and including 20 MW)	
CHP RFO and Bilateral Contracts	

Only the net capacity of these resources is recovered through the CAM (*i.e.*, NSGBA). As shown in Table VIII-39 below, the estimated value of the energy and ancillary services is subtracted from the total estimated annual payment for each contract. The resulting amount constitutes the net capacity costs.¹⁴⁶

¹⁴⁶ If a third party receives the use of the generation from a CAM-related resource through an energy auction or otherwise, the payment for the energy and ancillary services (*i.e.*, value) is recorded in the NSGBA. If SCE uses the generation of the resource to serve its bundled service customers' load, only then will the value of the energy be recorded in the ERRBA.

Table VIII-39
Updated 2027 Forecast CAM-Related Revenue Requirement
(\$000)

Line No.	Description	Total Est. Payment	Less: Energy/AS Value	CAM Net Cost
1.	New Generation PPAs and CPE Procurement ¹			
2.	Combined Heat and Power			
3.	UOG			
4.	LCR			
5.	ACES			
6.	Tolling GHG			
7.	Common Costs			
8.	Subtotal			
9.	FF&U			
10.	Total CAM-Related Purchased Power Revenue Requirement			

Areas shaded in gray are confidential per D.06-06-066, Matrix section V.C.

¹Costs and benefits of New Generation PPAs and CPE procurement are combined in this table for presentation purposes only.

In summary, SCE forecasts that the 2027 net capacity costs of the CAM-related PPA and CHP resources, including CPE-related procurement and administrative costs, will be (including FF&U).

2. Updated Estimated December 31, 2026 NSGBA Balance

The NSGBA was established pursuant to OP 2 of D.07-09-044, effective January 16, 2009.¹⁴⁷ The purpose of the NSGBA is to record the benefits and costs of PPAs associated with new generation resources pursuant to D.07-09-044 and D.06-07-029. The NSGBA also records costs and benefits associated with SCE's CPE-related procurement, in accordance with D.20-06-002, and emergency reliability procurement in accordance with D.21-02-028, D.21-03-056, D.21-12-015, and D.23-06-029. Pursuant to D.22-05-015, in the event that a non-IOU LSE declares bankruptcy or ceases providing retail service in California and has a capacity obligation under D.19-11-016 or D.21-06-035 and their retail customers are paying for capacity under the MCAM, the capacity shall revert to the relevant IOU, with the costs of the associated procurement allocated thereafter using the CAM detailed in D.06-07-030.¹⁴⁸ In addition, pursuant to D.23-02-040, if an IOU takes on the compliance obligation

¹⁴⁷ Advice 2284-E was approved by the Commission's Energy Division with an effective date of January 16, 2009.

¹⁴⁸ D.22-05-015, OP 10.

1 of another LSE due to bankruptcy or other reason for the LSE no longer providing retail service, cost
2 recovery for capacity procurement shall be through the CAM.¹⁴⁹

3 Costs associated with PPA contracts and eligible CHP contracts pursuant to D.10-12-035
4 include capacity and energy costs, applicable energy and fuel costs, and applicable costs to conduct
5 energy auctions. Benefits (credits) include energy and ancillary service revenues, proceeds from energy
6 auctions, and billed and unbilled revenue from a non-bypassable wires charge to all benefiting
7 customers. As set forth in Table 4 of Appendix A and Line No. 12 of Table VIII-34, SCE estimates that
8 the balance in the NSGBA as of December 31, 2026, will be an under-collection of \$9.669 million
9 (including FF&U). In order to estimate the year-end NSGBA balance, SCE used recorded amounts
10 from January 1, 2026, through September 30, 2026, plus a forecast of the activity SCE expects to record
11 in the NSGBA during October through December 31, 2026.

12 a) Measure Long Beach Surcharge Balancing Account Advice Letter

13 On April 4, 2025, SCE submitted Advice 5510-E, requesting authority to
14 implement a surcharge to recover the costs of a new utility users' tax (UUT) imposed by the City of
15 Long Beach on SCE's natural gas purchases that fuel a plant's production of electricity for delivery to
16 SCE's customers. SCE sought to establish a new Measure Long Beach Surcharge Balancing Account
17 (MLBSBA). As set forth in Advice 5510-E, SCE began to incur UUT under Measure LB starting in
18 2026.¹⁵⁰ These costs are currently being recorded in the NSGBA. SCE proposed to record the costs
19 associated with Measure LB's UUT and the revenues from the Measure LB surcharge in the MLBSBA,
20 which would be forecasted and trued up as part of SCE's annual ERRRA Forecast proceeding.¹⁵¹ If
21 Advice 5510-E is approved, SCE would remove the costs for Measure LB UUT from New System
22 Generation costs (CAM) and shift them over to the newly established MLBSBA. As of the filing of this
23 October Update, Advice 5510-E remains pending before the Commission.

¹⁴⁹ D.23-02-040, OP 11.

¹⁵⁰ Advice 5510-E, p. 17.

¹⁵¹ *Id.*, pp. 7-8.

3. Updated Estimated System Reliability MCAM-Related Costs

a) Introduction

In D.19-11-016, the Commission ordered incremental procurement of system-level RA capacity of 3,300 MW by all LSEs within the CAISO balancing authority area to address the potential for electricity system RA shortages beginning in 2021 through 2023. The resources procured pursuant to this order were required to come online at least 50 percent by August 1, 2021, 75 percent by August 1, 2022, and 100 percent by August 1, 2023. Procurement was to be conducted on an all-source basis, including both existing and new resources (except new gas-only resources), and could include LSE-owned resources when justified. SCE's proportional share of the 3,300 MW was 1,184.7 MW.¹⁵² Additionally, D.19-11-016 required the IOUs, including SCE, to procure additional system RA capacity on behalf of CCAs and ESPs who elected not to self-provide their proportional share (opt-out LSEs) and/or on behalf of CCAs and ESPs who elected to self-provide but failed to meet their obligations (non-performing LSEs). SCE's additional procurement requirement related to opt-out LSE elections was 56.6 MW.¹⁵³ In D.19-11-016, the Commission specified that the incremental capacity procured by the IOUs in response to the decision should be allocated on a non-bypassable basis through a MCAM mechanism to the customers of opt-out and non-performing LSEs and not the PCIA.¹⁵⁴ The decision also stated that "all costs" incurred by an IOU on behalf of customers of other LSEs will be compensated.¹⁵⁵

On May 19, 2022, the Commission adopted D.22-05-015, the *Decision on Modified Cost Allocation Mechanism for Opt-Out and Backstop Procurement Obligations*. D.22-05-015 authorizes the use of non-bypassable customer charges as the means through which to recover MCAM costs from customers of Opt-Out or Deficient LSEs. Pursuant to OPs 2 and 11 of D.22-05-015, on July

¹⁵² D.19-11-016, OP 3.

¹⁵³ See April 15, 2020 Administrative Law Judge's Ruling Finalizing Load Forecasts and Greenhouse Gas Benchmarks For Individual 2020 Integrated Resource Plan Filings and Assigning Procurement Obligations Pursuant To Decision 19-11-016 in R.16-02-007, p. 9.

¹⁵⁴ D.19-11-016, p. 67 and OP 5.

¹⁵⁵ *Id.*, p. 38.

1 18, 2022, SCE submitted Advice 4831-E to provide the implementation parameters for SCE's MCAM
2 and to establish the MCAMBA.¹⁵⁶ Advice 4831-E specified the cost recovery transfer of the SRPMA¹⁵⁷
3 recorded costs between the PABA, MCAMBA, and NSGBA.¹⁵⁸ On January 12, 2023, the Commission
4 adopted Resolution E-5240, which approved Advice 4831-E/E-A. SCE completed the transfers from the
5 SRPMA to the PABA, MCAMBA and NSGBA in January 2023. SCE has reflected the implementation
6 of Advice 4831-E/E-A in this Application and has been recording system reliability-eligible costs and
7 revenues to their respective balancing accounts since January 2023.

8 On December 19, 2023, the Commission adopted D.23-12-014, which granted a
9 PFM of D.22-05-015 filed jointly by San Diego Community Power and the Clean Energy Alliance on
10 October 28, 2022. D.23-12-014 allows for the use of the year-ahead load forecast instead of the actual
11 load being served as the basis for the one-time provision in D.22-05-15 for the purchase of RA capacity.
12 Any non-utility load-serving entity may elect to purchase additional RA capacity at the price specified in
13 D.22-05-015 based on the final 2023 RA year-ahead forecast from August 2022, but OCPA's eligibility
14 to purchase capacity is decreased by the amount of load from OCPA that returned to SCE bundled
15 service in June 2024. Because the eligible departing loads were previously included in the bundled
16 portion for the allocation between PABA, MCAMBA, and NSGBA, any resulting RA sales revenue
17 from D.23-12-014 is recorded to the 2019 subaccount of the PABA.

18 b) Updated 2027 MCAM Eligible Costs and Estimated December 31, 2026
19 MCAMBA Balance

20 As shown on Line No. 13 of Table VIII-34, the forecast of the 2027 fuel and
21 purchased power costs and revenues that will be recorded in the MCAMBA is \$3.797 million (including

¹⁵⁶ On August 16, 2022, SCE submitted supplemental Advice 4831-E-A, which updated the tables in the original advice letter but did not make material changes to the content.

¹⁵⁷ Due to a delay in the Commission adopting the design and implementation of the MCAM, in Advice 4218-E, SCE established the SRPMA to track costs and benefits incurred and received as a result of the incremental procurement undertaken pursuant to D.19-11-016. The SRPMA was used through the end of 2022. In January 2023, SCE began recording system reliability procurement-related costs and revenues directly into the MCAMBA, PABA and NSGBA.

¹⁵⁸ Advice 4831-E, pp. 3-5.

1 FF&U). As shown on Line No. 14 of Table VIII-34, the estimated 2026 adjusted year-end balance for
2 the MCAMBA is \$0.967 million.

3 **4. Updated Estimated Tree Mortality Contract Costs**

4 a) Introduction

5 On October 30, 2015, Governor Brown issued a Proclamation of a State of
6 Emergency to address a tree mortality crisis in California. In response to the Proclamation, on March
7 17, 2016, the Commission issued Resolution E-4770, which required the IOUs to enter into contracts to
8 purchase their share of at least 50 MW of collective generating capacity from biomass generation
9 facilities that use minimum prescribed levels of high-hazard zone (HHZ) material as feedstock. In 2016,
10 SB 859 was enacted, which included a new requirement for IOUs to procure their respective share of
11 125 MW from existing biomass facilities using prescribed amounts of dead and dying trees located in
12 HHZs as feedstock. SB 859 also required that procurement costs be recovered from all customers on a
13 non-bypassable basis. On October 21, 2016, the Commission issued Resolution E-4805 to implement
14 the requirements of SB 859. In D.18-12-003, the Commission determined that the NBC adopted in that
15 decision (*i.e.*, the Tree Mortality Non-Bypassable Charge (TM-NBC)) applied to all procurement
16 conducted pursuant to Resolution E-4770 and E-4805.

17 b) 2027 Tree Mortality Costs

18 As outlined in Advice 3955-E, SCE forecasts the annual net costs of its tree
19 mortality contracts¹⁵⁹ in its annual ERRA Forecast proceeding to set the TM-NBC on a forecast basis.
20 As shown on Line No. 19 of Table VIII-35, the forecast of the 2027 fuel and purchased power costs that
21 will record to the Tree Mortality Non-Bypassable Charge Balancing Account (TMNBCBA) is \$17.325
22 million (including FF&U). This forecast includes the estimated costs and benefits associated with
23 SCE's tree mortality contracts, as well as the audit expenses described below.

¹⁵⁹ SCE has two tree mortality contracts.

1 c) Recovery of BioRAM Audit Expenses in the TMNBCBA

2 BioRAM contracts obligate parties to utilize an independent third-party auditor to
3 determine the type of biomass fuel stock burned at the facility. Under the BioRAM program, fuel stock
4 from high hazard locations affords a higher contract energy price compared to other biomass fuels. Per
5 Resolutions E-4805 and E-4770, and then-Commission President Picker's concurrence of Resolution E-
6 4805, SCE is expected to perform audits of its BioRAM program.¹⁶⁰ For 2027, SCE forecasts audit
7 expenses of \$0.018 million, as reflected in Line No. 16 of Table VIII-35. Actual audit expenses
8 incurred in 2027 will record to the TMNBCBA.

9 **5. Updated Estimated December 31, 2026 TMNBCBA Balance**

10 Pursuant to OPs 5 and 12 of D.18-12-003, SCE submitted Advice 3955-E on February 19,
11 2019 to establish the TMNBCBA. The purpose of the TMNBCBA is to record the actual costs, energy
12 and ancillary services revenues, REC sales-related revenues (or a benchmark value if such sales are
13 impossible) and RA sales-related revenues (or a benchmark value if such sales are impossible) of SCE's
14 tree mortality contracts. Additionally, the TMNBCBA records the billed TM-NBC revenues received
15 from customers, which are recovered through the PPP charge.¹⁶¹

16 As shown in Table 5 of Appendix A and on Line No. 19 in Table VIII-34, SCE estimates
17 a December 31, 2026 under-collection of \$2.607 million (including FF&U) in the TMNBCBA.

18 **6. Estimated BioMAT Contracts Costs**

19 a) Introduction

20 SB 1122 (Rubio, 2012) created a bioenergy feed-in tariff within the RPS program
21 and required the IOUs to procure an additional 250 MW of renewable feed-in tariff resources from
22 small-scale bioenergy projects that commence operation on or after June 1, 2013 (Bioenergy Market

¹⁶⁰ See President Picker's concurrent of Resolution E-4805: "Under the terms of the contract, the utilities have audit rights to affirm that generators are in fact meeting their fuel feedstock requirements. It is my expectation that the utilities **shall** [emphasis added], for the first year of their contracts, conduct quarterly audits of each facility they contract with. Upon completion of these audits, I request that each utility submit their audit report to my office for review. In subsequent contract years, I expect each utility to conduct at least two audits per year."

¹⁶¹ SCE first implemented the TM-NBC in rates on April 13, 2020.

Adjusting Tariff (BioMAT) Resources or Contracts). On September 1, 2020, the Commission issued D.20-08-043, which, among other things, modified cost allocation for the BioMAT program by allocating BioMAT program costs through a non-bypassable charge (NBC) to all customers in each IOU's service area, and collecting the new NBC as part of the IOU's PPP charge.¹⁶² In accordance with OP 3 of D.20-08-043, on October 1, 2020, SCE submitted Advice 4306-E to establish the BioMAT Non-Bypassable Charge Balancing Account (BMNBCBA)¹⁶³ to record the actual costs, energy and ancillary services revenue, RPS value, and RA value of the BM Contracts (*i.e.*, the net costs). Additionally, the BMNBCBA records the BM-NBC revenues received from customers. On April 3, 2025, Resolution E-5376 extended the deadline for SCE to procure its proportionate share of 125 megawatts of eligible BioRAM contracts to July 1, 2025.

b) Updated 2027 BioMAT Contract Costs

As outlined in Advice 4306-E, SCE forecasts the annual net costs of its BioMAT contracts in its annual ERRA Forecast proceeding to set the BM-NBC on a forecast basis. As shown on Line No. 19 in Table VIII-35, the forecast for the fuel and purchased power costs that will record to the BMNBCBA is \$2.335 million (including FF&U).

c) Updated CCA BioMAT Program

D.23-11-084 set rules to enable CCAs to participate in the BioMAT program, as authorized by Assembly Bill 843. Specifically, each CCA that elects to participate in the BioMAT program must submit a Tier 3 advice letter that seeks Commission approval of eligible BioMAT forecasted revenue requirements recorded in CCA balancing accounts that reflect BioMAT program net costs, including power purchase agreement costs, Accion BioMAT platform integration costs, and independent third-party vendor costs required for joint CCA/utility program administration on or before February 1, 2024.¹⁶⁴ After Commission approval of the Tier 3 advice letters, SCE would then include

¹⁶² Prior to the implementation of D.20-08-043, BioMAT program costs were recovered from bundled service customers and departing load customers on a vintage basis via the PCIA rates, with customer revenues and BioMAT costs recording to the applicable subaccounts of the PABA.

¹⁶³ D.20-08-043, OP 3.

¹⁶⁴ D.23-11-084, OP 12.

1 the Commission-approved CCA BioMAT costs in the October Update to its ERRRA Forecast
2 Application.¹⁶⁵ If the Commission does not approve pending Tier 3 advice letters by 20 days prior to
3 the October Update filing date set in the annual ERRRA Forecast proceeding, SCE shall not include these
4 costs in the October Update.¹⁶⁶ If the Commission does not approve pending Tier 3 advice letters by 20
5 days prior to the October Update, but does approve the Tier 3 advice letter by Resolution 10 days prior
6 to the submittal of SCE's annual year-end consolidated revenue requirement and rate change advice
7 letter, SCE must incorporate the approved CCA BioMAT costs into that advice letter.¹⁶⁷ If the
8 Commission does not approve pending Tier 3 advice letters by 10 days prior to SCE's advice letter
9 submittal, SCE must include the forecast CCA BioMAT costs in its advice letter but would not disburse
10 the funds to the CCAs until Commission disposition of the associated Tier 3 advice letter through a
11 Resolution and would only disburse the amount approved within the disposition.¹⁶⁸ On February 2,
12 2026 and January 30, 2026, Central Coast Community Energy (3CE)¹⁶⁹ and Orange County Power
13 Authority (OCPA),¹⁷⁰ respectively, submitted advice letters stating that each had no forecasted revenue
14 requirements for their respective BioMAT Programs. While 3CE's BioMAT advice letter did contain a
15 revenue requirement, it was associated with a single project, located in Pacific Gas and Electric
16 Company's (PG&E) service area, and therefore does not impact this Application.¹⁷¹

17 **7. Updated Estimated December 31, 2026 BMNBCBA Balance**

18 In accordance with OP 3 of D.20-08-043, SCE submitted Advice 4306-E on October 1,
19 2020 to establish the BMNBCBA.¹⁷² The purpose of the BMNBCBA is to record the actual costs,

¹⁶⁵ *Id.*

¹⁶⁶ *Id.*, OP 13.

¹⁶⁷ *Id.*, OP 14.

¹⁶⁸ *Id.*, OP 15.

¹⁶⁹ 3CE Advice 51-E, which was approved by Resolution E-5471 on September 3, 2026.

¹⁷⁰ OCPA Advice 15-E, which was approved by Resolution E-5459 on June 11, 2026.

¹⁷¹ 3CE Advice 51-E, p. 7.

¹⁷² Advice 4306-E was approved by the Commission's Energy Division on November 2, 2020, with an October 31, 2020 effective date.

1 energy and ancillary services revenue, RPS value, and RA value of the BM Contracts (*i.e.*, the net
2 costs). Additionally, the BMNBCBA records the BM-NBC revenues received from customers.

3 As shown in Table 6 of Appendix A and on Line No. 20 in Table VIII-34, SCE estimates
4 a December 31, 2026 over-collection of \$2.927 million (including FF&U) in the BMNBCBA.

5 **8. Updated Estimated 2027 Spent Nuclear Fuel Revenue Requirement**

6 SCE requests that the Commission adopt a revenue requirement of \$5.433 million
7 (including FF&U) associated with spent nuclear fuel in its 2027 ERRRA Forecast Proceeding delivery
8 service revenue requirement, as discussed in Chapter IV. These amounts are considered fuel-related
9 costs and are not litigated elsewhere. See Table VIII-40 below.

Table VIII-40
Updated 2027 Forecast Spent Nuclear Fuel Revenue Requirement
(\$000)

Line No.	Component	Amount
1.	Spent Nuclear Fuel (Interim Storage)	\$ 5,367
2.	FF&U	\$ 67
3.	TOTAL	\$ 5,433

IX.

UPDATED 2027 FORECAST COST RESPONSIBILITY SURCHARGES

The purpose of this chapter is to describe the methodology and inputs used to determine the 2027 Indifference Amount, which is paid for by bundled service customers through generation rates, and by DA, Customer Generation Departing Load (CGDL), CA, and CCA customers, collectively referred to as Departing Load customers, through the CTC and PCIA rates.¹⁷³

Calculations for the CTC and PCIA rates are performed using the Updated PCIA Workpaper Template¹⁷⁴ included in Appendix B, which reflects the modifications adopted in D.21-03-051. Specifically, D.21-03-051 approved a petition for modification filed by the IOUs to update the PCIA workpaper template to correct a methodology error related to the application of line losses in the calculation of the Indifference Amount. In addition, the Commission approved the use of energy volumes measured at the generator meter instead of the customer meter for the PCIA and CTC rate calculations.¹⁷⁵

Table IX-41 provides a comparison of the CRS revenue requirement included in SCE's May Testimony and as updated herein, which has increased substantially. Since the May Testimony, SCE's forecast of the 2027 Indifference Amount has increased by approximately 687 percent, primarily as a result of applying the updated MPBs provided by the Commission's Energy Division on October 1, 2026. The final overall PCIA revenue requirement increased primarily due to the increase to the forecasted 2026 year-end PABA balance, which was largely driven by Retained RPS being trued-up using the 2026 Final RPS MPB and lower than forecast CAISO market revenues throughout 2026.

¹⁷³ The CTC and PCIA are recovered from Departing Load customers through the CRS tariff. The CRS also includes the Wildfire Fund NBC, which replaced the Department of Water Resources (DWR) Bond Charge effective October 1, 2020. *See* Advice 4301-E. The Wildfire Fund NBC listed in the CRS rates in Appendix B is the currently effective Wildfire Fund NBC.

¹⁷⁴ The revised workpaper was included in D.21-03-051 as Appendix A and identified as the Updated PCIA Workpaper Template.

¹⁷⁵ *See* D.21-03-051, OPs 1 and 2.

Table IX-41
Updated Forecast Indifference Amount Calculation – May Compared to October

	May Testimony	Amended October Update		
PCIA Revenue Requirement	Amount (\$000)	Amount (\$000)	Difference (\$000)	Difference (%)
Portfolio Cost	\$ 4,571,489	\$ 4,587,858	\$ 16,369	0%
Market Value	\$ (4,820,935)	\$ (3,123,525)	\$ 1,697,410	-35%
Energy Value	\$ (1,212,191)	\$ (1,190,631)	\$ 21,560	-2%
RPS Value	\$ (1,895,042)	\$ (478,381)	\$ 1,416,661	-75%
RA Value	\$ (1,713,702)	\$ (1,454,513)	\$ 259,189	-15%
One-Time Adjustments	\$ 69	\$ 142	\$ 73	106%
Indifference Amount	\$ (249,377)	\$ 1,464,475	\$ 1,713,852	687%
2026 YE PABA Balance	\$ 551,030	\$ 1,421,100	\$ 870,070	158%
UOS Separator	\$ 29,682	\$ 29,682	\$ -	0%
2025 GRCRRMA	\$ 50,869	\$ 50,869	\$ -	0%
2026 YE Erra BA Balance	\$ (326,756)	\$ (1,273,180)	\$ (946,425)	-290%
PCIA Revenue Requirement	\$ 55,449	\$ 1,692,946	\$ 1,637,497	2953%
With U¹	\$ 55,614	\$ 1,697,989	\$ 1,642,375	2953%

Notes:

¹ SCE applied the Uncollectibles factor of 0.997030 from Advice 5663-E.

A. Background

The CRS Indifference Amount, as established in D.02-11-022 and modified or clarified by D.03-07-030, D.06-07-030, D.08-09-012, D.11-12-018, Resolution E-4475, D.18-10-019, D.19-10-001, D.21-03-051, D.23-06-006, D.25-06-049 and D.26-09-047, is designed to maintain bundled service customer indifference to departing load by ensuring that Departing Load customers remain responsible for the stranded, or above-market, costs of generation resources procured on their behalf prior to their departure from bundled service.¹⁷⁶ To derive this “Indifference Amount,” SCE quantifies the difference between the forecast annual cost of the generation portfolio procured by SCE (Total Portfolio Cost), and the forecast market value of that portfolio (defined as the forecast output of the resources in the generation portfolio multiplied by the energy, RPS, and RA MPBs).¹⁷⁷

¹⁷⁶ See Resolution E-4475, p. 2.

¹⁷⁷ The MPBs are now referred to as the Energy Index, RPS Adder, and RA Adder.

1 In D.08-09-012, the Commission adopted the practice of vintaging the utility's generation
2 portfolio to ensure that Departing Load customers are held responsible only for generation procured
3 prior to the date of their departure from bundled service. Accordingly, SCE calculated Indifference
4 Amounts for each "vintage year" based on the generation resources that were committed in each
5 calendar year.¹⁷⁸ These Indifference Amounts represent the revenue requirements in each vintaged
6 subaccount of the PABA.

7 The vintaged PABA revenue requirements are then allocated to rate groups using generation
8 revenue allocators approved in SCE's GRC Phase 2 proceeding normalized to account for each rate
9 group's kWh sales forecast by vintage and divided by forecast sales by vintage (also referred to as
10 billing determinants) to set the final CTC and PCIA rates. The CTC rate is used to recover the above-
11 market costs of pre-restructuring resources such as eligible QFs and is the same for all vintages. The
12 PCIA rates are used to recover the above-market costs of all non-CTC-eligible resources (e.g., UOG and
13 "New-World" generation resources as authorized in D.04-12-048 and modified by D.18-10-019) and
14 vary by vintage based on the generation resources included in that vintage.¹⁷⁹

15 **B. Updated RA SOD Framework**

16 In D.23-04-010, the Commission affirmed that it intended to move forward with SOD
17 implementation in 2025. On June 20, 2024, the Commission approved D.24-06-004, which confirmed
18 the start of the SOD framework in 2025. On August 16, 2024, SCE served Supplemental Testimony in
19 its 2025 ERRA Forecast proceeding to detail its proposed interim solution for implementing SOD in its
20 PCIA ratemaking, which SCE has also applied in this Application. In the 2025 ERRA Forecast (A.24-
21 05-007), the Commission found SCE's proposed methodology to be a reasonable execution of

¹⁷⁸ Pursuant to D.08-09-012, customers are assigned a vintage based on the date of their departure. If they departed on or before June 30 of a given year, they are assigned to the prior year's vintage. Alternatively, if they departed on or after July 1 of a given year, they are assigned that year's vintage.

¹⁷⁹ As described in D.06-07-030, the CTC and PCIA are set such that the sum of the two equals the Indifference Amount.

Commission guidance for how RA is counted for compliance purposes.¹⁸⁰ This methodology was also approved in SCE’s 2026 ERRRA Forecast (A.25-06-008).¹⁸¹

The SOD framework transitions the CPUC’s RA program from a single NQC check in the peak hour to a capacity check in every hour of the “worst day” (24 total) for each month. The SOD framework also requires charging sufficiency for storage resources. These changes necessitate a shift in how the value of RA is calculated, moving away from the traditional NQC-based method to a more dynamic and granular approach that aligns with the new SOD rules.

To represent SCE’s RA position as a single monthly number, SCE converts its hourly position into a monthly position by taking an average of its hourly optimized supply and creating a “baseload equivalent” position. In addition to this baseload equivalent position, SCE accounts for its excess energy storage quantities to better represent its procurement need, especially for energy sufficiency to charge these energy storage resources. The following assumptions were used for determining price and quantity:

1. Price

SCE does not assume any changes to the price, or the MPB, and is using the Commission-issued MPB. Traditionally, the RA price has been indicative of 1 kW-month of reliability, measured based on the net-peak hour. This means that the price was reflective of the capacity to provide reliable power during the period of highest demand. However, under the SOD framework, the RA price would reflect the price for 1 kW-month of reliability but now measured over an entire 24-hour period. This change recognizes the fact that reliability is no longer only about meeting the peak demand but ensuring reliable power during the 24-hour period of demand.

Moreover, the requirement for RA compliance in each hour of the day implies the possibility of an hourly structured RA price. This is because higher RA requirements in certain hours can lead to higher RA price in those hours. The relevance of varying requirements within hours is

¹⁸⁰ See D.24-12-039, p. 75.

¹⁸¹ See D.25-12-028, p. 119.

1 somewhat mitigated by storage. Storage reshapes the RA requirement curve by absorbing capacity for
2 charging during the long RA hours, thereby increasing requirements, and providing capacity during
3 short RA hours, thereby decreasing requirements.

4 **2. Quantity**

5 As discussed above, under the “single slice” regime, the quantity of reliability has been
6 measured as the NQC, which represents the capacity a resource can offer to the grid during the single
7 peak hour of each month. Under the SOD framework, a resource’s RA quantity must reflect the reliable
8 capacity provided by the resource over a full 24-hour period. SCE is representing the RA quantity of
9 different resource types based on a “baseload equivalent” RA quantity and to report resources’ NQC
10 values in the PCIA workpaper based on the optimized amount the resource contributes towards SCE’s
11 compliance requirements. The baseload-equivalent RA quantity normalized by the capacity of the
12 resource signifies the effective contribution of the resource towards meeting the SOD requirement. This
13 measure can be referred to as the “SOD RA Effectiveness Factor.” Below is a description of the
14 methodology to estimate RA quantity by resource type:

15 a) Baseload Resources

16 For baseload resources, which deliver consistent output throughout the day, their
17 RA quantity remains unchanged when transitioned to the SOD framework. The SOD RA Effectiveness
18 Factor for these resources can be up to 100 percent of their capacity, although this may be reduced for
19 de-rates and operational constraints as reflected in their NQC.

20 b) Intermittent Resources

21 For intermittent resources (*e.g.*, wind, solar), the baseload equivalent can be
22 estimated by the average of their hourly exceedance values output. In the SOD framework, the RA
23 counting methodology for intermittent resources like wind and solar has transitioned to an exceedance-
24 based approach, moving away from the traditional ELCC-based approach. The ELCC provides a single
25 value for a month, whereas the exceedance value, available in the Master Resource Database (MRD)
26 published by the CPUC, offers a value for each hour of the day for a specific month. Just like ELCC,
27 the exceedance value also varies depending on the region and technology. By taking the average of the

1 exceedance value over a 24-hour period, the SOD RA Effectiveness Factor for intermittent resources
2 can be determined. With the use of energy storage, the excess power generated by intermittent resources
3 during their peak times can be stored and then discharged when their generation drops off. This
4 effectively flattens the power generation profile over a 24-hour period, making it equivalent to a single
5 capacity number that is constant throughout the day.

6 c) Stand-alone Storage

7 In the SOD framework, storage resources are not assigned specific pre-
8 determined hourly quantities for the hourly capacity determination. Instead, storage resources are
9 optimized to address RA shortfalls during any hour of the day. Furthermore, the CPUC's QC
10 methodology for energy storage has not changed. It is still based on the capacity (MW) level at which
11 the storage resource is capable of discharging for four or more consecutive hours. Under the previous
12 RA framework, storage resources with a duration of four hours or more are deemed equivalent to
13 baseload for RA counting, underscoring their ability to provide capacity during the peak period.
14 Therefore, their RA quantity can still be based on their NQC value. However, the SOD rules introduced
15 an additional requirement: storage resources can only be counted towards RA if there is sufficient
16 charging capacity. The combination of storage resources and the charging RA capacity provides a
17 solution equivalent to baseload. Therefore, the effective contribution from storage is calculated as the
18 storage NQC minus the RA capacity needed for charging.

19 The RA capacity needed for charging considers round trip efficiency (RTE) and
20 duration of the storage resource. A storage resource with poor RTE would require more RA charging
21 capacity and, as a result, would have a lesser effective RA contribution and vice versa. As a result, the
22 formula for calculating the RA quantity of storage resources in the SOD framework can be stated as
23 follow: $NQC - NQC \times 4 / 24 / RTE$.

24 d) Hybrid/Co-located Storage

25 The total RA quantity of hybrid or co-located resources is the sum of the
26 renewables and storage components limited by the Point-of-Interconnection (POI) limit. The RA
27 quantity of the renewable component is determined based on the average of the exceedance values as

1 discussed above. The RA quantity of the storage component is estimated based on the previously
2 described formulation.

3 For energy storage resources that are restricted from charging from the grid, the
4 storage capacity can be adjusted to match the chargeable capacity from the renewable component. In
5 accordance with D.24-06-004, there is no reduction in the QC value of the renewable component.

6 In the case of energy-only (EO) resources, the storage is credited for charging
7 capacity from the renewable component. The EO component remains bundled with the storage system.
8 In accordance with OP 9 of D.24-06-004, an EO resource can meet the storage charging sufficiency
9 requirement if it exclusively charges a paired storage system, regardless of whether the paired storage
10 can also charge from the grid. Similarly, in the case of a co-located resource that is partially or fully
11 deliverable, the variable energy component (if contracted by SCE) is counted towards RA and off-site
12 charging sufficiency requirements up to its deliverable capacity, provided the combined generation and
13 storage output does not exceed the point of interconnection in the same hour, as set forth in OP 10 of
14 D.25-06-048.

15 An adjustment was required to reduce the RA capacity for MCAM contracts in
16 PCIA vintage 2019 and increase the RA capacity of solar resources in PCIA vintages 2011, 2014, and
17 2015 to more accurately depict the value of these co-located resources.

18 SCE's generic RA procurement costs and excess sales revenues are based on its
19 position under the SOD framework. To create its position under the SOD framework, SCE utilized its
20 internal optimization tool and the MRD from the Commission to create hourly 2027 profiles for
21 baseload resources. Additionally, the tool was used to optimize SCE's energy storage portfolio to fill
22 the remaining open position. SCE's internal tool provides the total 24-hour profile of the unit. For its
23 October Update, SCE uses its final 2027 requirements and final CAM and DR allocations from the
24 CPUC to determine its position. SCE also used the final 2027 MRD, as provided by the Commission on
25 September 25, 2026.



1
2
3
4
5
6
7
8
9
10 **C. Updated Total Portfolio Costs**

11 The Portfolio Costs for each vintage are determined based on the forecast fixed and variable
12 costs, consistent with those outlined in Table IV-9, of generation resources forecast to be used to serve
13 bundled service customers in 2027. Specifically, these costs include the authorized base generation
14 capital revenue requirement, as determined in SCE’s GRC Phase 1 proceeding,¹⁸² fuel costs, and direct
15 GHG costs for all eligible UOG;¹⁸³ RPS-eligible contract costs; QF and non-CAM-eligible CHP
16 contract costs; all bilateral and RFO contract costs, including fuel costs and direct GHG costs if
17 applicable; and any applicable one-time refunds or adjustments. The Total Portfolio costs do not include
18 any costs associated with CAM, TMNBCBA, BMNBCBA, MCAMBA, and LCR-eligible resources,
19 ISO-load related costs, or Residual Net Position spot market (*i.e.*, “short-term”) purchases.

20 As shown in Table IX-41, the change in the forecast of Total Portfolio Costs between the May
21 Testimony and the October Update was de minimis, with the percent change rounding down to zero
22 percent.

¹⁸² SCE’s PCIA workpaper currently reflects the adopted 2026 AGBRR approved in Advice 5677-E. SCE will submit its 2027 Post Test-Year Ratemaking Advice Letter no later than December 1, 2026. The AGBRR will then be updated for 2027 in the implementation advice letter.

¹⁸³ SCE’s utility-owned Peakers’ net costs are recovered through the CAM and are thus not CRS-eligible.

1 **D. Updated Total Portfolio Market Value**

2 The total portfolio market value of PABA-eligible resources is calculated, on a forecast basis,
3 using “Forecast” MPBs in accordance with D.18-10-019, D.19-10-001, D.25-06-049 and D.26-09-047.
4 The first MPB, now referred to as the “Energy Index,” reflects the estimated value of each unit of energy
5 in SCE’s PABA-eligible portfolio, in dollar value per megawatt hour (\$/MWh).¹⁸⁴ The second MPB,
6 now referred to as the “RPS Adder,” reflects the estimated incremental value of each unit of Forecast
7 Retained¹⁸⁵ and Forecast Sold RPS-eligible energy, also in \$/MWh. The third MPB, now referred to as
8 the “RA Adder,” reflects the estimated value of each unit of Forecast Retained and Forecast Sold
9 capacity in SCE’s PABA portfolio that can be used to satisfy RA obligations, in dollar value per
10 kilowatt (\$/kW). The RA Adder previously had three subcomponents for system, local, and flexible
11 RA. As further discussed below, D.25-06-049 modified the RA MPB methodology adopted in D.19-10-
12 001 to calculate a single RA MPB. All other things being equal, decreases to the MPBs will increase the
13 CTC and vintaged PCIA rates; conversely, increases to the MPBs will decrease the CTC and vintaged
14 PCIA rates.

15 As shown in Table IX-41, SCE’s updated forecast of the Total Portfolio Market Value decreased
16 by approximately 35 percent compared to SCE’s May Testimony.¹⁸⁶ The decrease is mainly the result
17 of the updated 2027 Forecast MPBs provided by the Commission’s Energy Division on October 1, 2026.
18 Table IX-42 provides a comparison of the Forecast MPBs used in SCE’s 2026 ERRRA Forecast
19 proceeding (both the May submittal and the October Update) and the Forecast MPBs used in this filing,
20 which are discussed further in the sections below.

¹⁸⁴ This MPB had previously been referred to as the “Brown Power” component and was most recently updated in D.23-06-006.

¹⁸⁵ In accordance with D.26-09-047, Pre-2019 Banked RECs are valued at \$0.00/MWh.

¹⁸⁶ Market Values are shown as a negative number because they are recorded as credits in PABA, with higher Market Value resulting in a lower Indifference Amount.

Table IX-42
Comparison of Forecast PCIA Market Price Benchmarks

Market Price Benchmark (MPB)	2026 ERRRA Forecast May Submittal	2026 ERRRA Forecast ¹ October Submittal	2027 ERRRA Forecast May Submittal	2027 ERRRA Forecast ¹ October Submittal	Percent Change Between May and October Filings
Energy Index	\$40.56/MWh	\$40.00/MWh	\$32.55/MWh	\$32.54/MWh	0%
RPS Adder	\$71.24/MWh	\$62.45/MWh	\$62.45/MWh	\$12.69/MWh	-80%
RA Adders	(intentionally left blank)				
System	\$483.72/kW-yr	\$138.36/kW-yr	\$138.36/kW-yr	\$120.24/kW-yr	-13%
Local	\$134.76/kW-yr				
Flexible	\$203.64/kW-yr				

¹ Per D.25-06-049, the RA MPBs have been consolidated into a single RA MPB.

1. Updated Energy Value

SCE’s forecast of the Energy Value decreased by approximately two percent compared to SCE’s May Testimony, driven primarily by the slight decrease in the updated generation forecast for SCE’s UOG resources in 2027.

The Energy Value is the estimated financial value, measured in dollars, that is attributed to the energy component of SCE’s PABA-eligible portfolio for a given year. It is calculated, on a forecast basis, by multiplying the Energy Index MPB by the estimated amount of energy produced by resources in SCE’s PABA-eligible portfolio.

On June 13, 2022, in R.17-06-026, SCE and the other investor-owned electric utilities (collectively, the “Joint IOUs”) submitted a proposal to update the Energy Index MPB calculation used in setting the forecast PCIA rates. The Joint IOUs’ proposal recommended that the Energy MPB be modified to:

- Apply on- and off-peak weightings that are based on time weightings,
- Calculate portfolio weighting using the historical annual weighted average price of the PCIA-eligible portfolio divided by the average 12-month CAISO trading hub price (SP-15 for SCE), and
- Apply portfolio weightings to determine the forecast Energy Index MPB that is used to set PCIA rates on a forecast basis.

1 On June 8, 2023, the Commission adopted the Joint IOU proposal in D.23-06-006,
2 finding that the updated methodology will increase the accuracy of the Energy Index MPB calculations
3 without creating unreasonable administrative burden.¹⁸⁷ Appendix B of D.23-06-006 outlines the
4 updated calculation.

5 In accordance with D.23-06-006, SCE applied time weightings used in the calculation of
6 the Energy Index MPB based on the CAISO trading schedule that considers hours ending (HE) 7-22
7 from Monday through Saturday as “on-peak”; and HE 1-6 and 23-24 from Monday through Saturday
8 and HE 1-24 on Sunday and all North American Electric Reliability Corporation (NERC) holidays as
9 “off-peak.”

10 SCE then calculated a portfolio weight, which is intended to represent the actual value
11 that the PCIA portfolio receives in the CAISO market relative to the CAISO Day-Ahead SP15 prices.
12 The resulting weight is applied to the results of the time-weight and forecasted energy market prices.
13 For 2027, SCE utilized historical data from its PCIA-eligible portfolio for the years 2023-2025.

14 SCE added or removed data for any resources that are 300 MW or larger, as required by
15 D.23-06-006. Specifically, for the 2027 calculation, SCE removed historical data for one project, [REDACTED]

16 [REDACTED]

17 [REDACTED]

18 [REDACTED]

19 After compiling all available resource data, SCE divided its annual PABA portfolio
20 revenue by its portfolio megawatt-hours (MWh) to arrive at an average implied portfolio price of
21 \$32.54/MWh and an overall portfolio weighting of 83 percent, as shown in Table IX-43.¹⁸⁸

22 For the October Update, SCE updated the on- and off-peak prices using the 2027
23 Forecast Energy MPBs.

¹⁸⁷ See D.23-06-006, pp. 38-39.

¹⁸⁸ SCE used the 2027 Forecast MPBs for the on- and off-peak prices for 2027, as published by the Commission on October 1, 2026.

Table IX-43
Updated PABA Portfolio Weight (2022-2024 Actuals) and Calculated Energy MPB

Portfolio Weight Calculation:	PABA Portfolio Revenue (\$000)	Portfolio MWh	Avg Price (\$/MWh)	Actual SP15 (\$/MWh)	Portfolio Weights
2023- Actuals	\$ 1,865,437,018	33,818,343	\$ 55.16	\$ 58.99	94%
2024- Actuals	\$ 1,072,392,255	39,425,457	\$ 27.20	\$ 32.68	83%
2025- Actuals	\$ 827,345,659	36,274,323	\$ 22.81	\$ 32.22	71%
2027 -3 year Average	\$ 3,765,174,931	109,518,124	\$ 34.38	\$ 41.29	83%

Final Energy MPB Calculation	Energy MPB (\$/MWh) ¹	Time Weights (%)	Portfolio Weight (%)	Calculated Benchmark : (Energy MPB * Time Weight * Portfolio Weight)
On Peak	\$ 34.41	55%	83%	\$ 15.86
Off Peak	\$ 44.89	45%	83%	\$ 16.68
Total Benchmark:				\$ 32.54

2. Updated RA Value

The RA Value is the estimated financial value, measured in dollars, that is attributed to the RA component of SCE's PABA-eligible portfolio in a given year. SCE's forecast of the RA value decreased by approximately 19 percent compared to SCE's May Testimony, driven primarily by the application of the 2027 Forecast RA Adder, which decreased 13 percent, and an update to the forecast quantity of capacity from energy storage resources based on the latest MRD co-located VER information available.

Table IX-44
Forecast RA Value – Comparison of Inputs

Forecast RA Value		May Testimony		October Update	
RA Product Categories	Price (\$/kW-yr)	Quantity (MW)	Price (\$/kW-yr)	Quantity (MW)	
Forecast Retained RA	(intentionally left blank)		(intentionally left blank)		
System	\$138.36		\$120.24		
Local	\$138.36		\$120.24		
Flexible	\$138.36		\$120.24		
Excess RA	(intentionally left blank)		(intentionally left blank)		
	Actual prices for sales up to 45 days prior to ERRA Forecast filing		Actual prices for sales up to 45 days prior to ERRA Forecast filing		
Actual Sold RA ¹					
Forecast Sold RA	(intentionally left blank)		(intentionally left blank)		
System ²	\$138.36		\$120.24		
Local	\$138.36		\$120.24		
Flexible	\$138.36		\$120.24		
Forecast Unsold	\$0		\$0		

Areas shaded in gray are confidential per D.06-06-066, Matrix section V.C.

¹ SCE includes revenue from RA swaps in this category (see Appendix B workpapers) but swaps are not reflected in the Quantity column.

² Includes any additional amount needed to meet the 18 percent planning reserve margin for October (see Appendix B workpapers).

For 2027, SCE's Forecast Sold RA percentage is based on the amount of actual sales in 2026 as of September 30, 2026.

¹⁸⁹ SCE reserved 200 MW as a buffer for portfolio management purposes.



SCE also forecast the amount of RA expected to remain unsold (Forecast Unsold) and applied a \$0 value (for forecast purposes only and subject to value assignment at actual sale prices, if any). Actual sales revenues realized for Forecast Unsold RA in 2027, if any, will be recorded in the PABA (or recorded at the RA MPB if SCE uses any of the Forecast Unsold RA in 2027 to subsequently serve bundled service customer needs). Table IX-45 shows the comparison of Excess RA inputs used in the May Testimony and the October Update.

SCE has incorporated a pro-ration of its sold and unsold volumes between its system, local, and flexible capacity based on the total volumes in SCE's PABA portfolio. These forecasted excess sales volumes are valued at the RA MPB and all unsold excess (*i.e.*, Forecast Unsold RA) will continue to be valued at \$0 on a forecast basis.

Table IX-45
Excess RA Comparison – May Testimony vs. October Update

	May (MW)	October (MW)	Change (MW)
Excess RA			
Forecast Sold + Actual Sold RA			
Forecast Unsold RA			

The excess RA inputs in SCE’s May Testimony were derived from SCE’s internal forecast for 2027 RA. On September 25, 2026, SCE received its final RA allocations for its 2027 year-ahead RA requirements and allocations from the Commission. These allocations include an 18 percent PRM and an effective PRM procurement target ranging from 1,260 to 2,300 MW for the months of June through October, as adopted in Track 3 of the RA proceeding (R.23-10-011) and approved in D.25-06-048. Additionally, SCE has incorporated its interim RA SOD framework, which reflects the 24-hour SOD compliance requirement, consistent with its approach in the 2025 and 2026 ERRRA Forecast. Using these assumptions, SCE’s 2027 RA position is now [REDACTED] in all months relative to the SOD position used in the May Testimony. [REDACTED]

Due to the changes outlined above, SCE now projects its Excess RA volume to be [REDACTED] than the estimate included in SCE’s May Testimony.

3. Updated RPS Value

The RPS Value is the estimated financial value, measured in dollars, that is attributed to the renewable energy component of SCE’s PABA-eligible portfolio in a given year. It is calculated, on a forecast basis, as outlined in Table IX-46.

SCE’s forecast of the RPS Value decreased by 80 percent compared to SCE’s May Testimony, primarily as a result of the decrease in the 2027 Forecast RPS Adder, as shown in Table IX-46. [REDACTED]

Table IX-46
Forecast RPS Value – Comparison of Inputs

Forecast RPS Value		May Testimony ³	October Update		
RPS Product Categories		Price (\$/MWh)	Quantity (GWh)	Price (\$/MWh)	Quantity (GWh)
Forecast Retained RPS					
REC's that Cannot be Allocated ¹		\$62.45		\$12.69	
Voluntary Allocation					
Market Offer (SCE Portion)		\$62.45		\$12.69	
Purchased REC's (PCC-1) ²		\$62.45		\$12.69	
Purchased REC's (PCC-3) ²		\$62.45		\$12.69	
Banked REC's (post-2018)		\$62.45		\$12.69	
Banked REC's (pre-2019)		\$0.00		\$0.00	
Non-SCE Voluntary Allocation (Long-Term)		\$62.45		\$12.69	
RPS Sold through Market Offers (Long-Term)		Actual prices for sales up to 45 days prior to ERRA Forecast filing		Actual prices for sales up to 45 days prior to ERRA Forecast filing	
Actual Sold RPS		Actual prices for sales up to 45 days prior to ERRA Forecast filing		Actual prices for sales up to 45 days prior to ERRA Forecast filing	
Forecast Unsold		\$0.00		\$0.00	

Areas shaded in gray are confidential per D.06-06-066, Matrix section V.C.

¹ Includes CREST, Re-MAT, Bio-MAT, GTSR, MTR/Clean Energy etc.

² If SCE's proposal to use Purchased REC's is adopted. SCE has updated in the October Update to reflect the REC's being used based on SCE's proposal rather than generation year.

³ SCE updated the May Testimony values to correct formula errors that were inadvertently included.

D.18-10-019 considered the adoption of a Voluntary Allocation (VA) and Market Offer (MO) (VAMO) in the second phase of the 2017 PCIA proceeding¹⁹⁰ “to consider the development and implementation of a comprehensive solution to the issue of excess resources in utility portfolios.”¹⁹¹ The Commission adopted VAMO in the second phase of the PCIA proceeding in D.21-05-030, which voluntarily allocates RPS to LSEs in an IOU’s service area. Costs for the allocated RPS is valued using the RPS MPB.¹⁹² Any unallocated RPS resources were made available through a market offer process.

¹⁹⁰ R.17-06-026.

¹⁹¹ D.18-01-019, p. 3.

¹⁹² D.21-05-030, OP 5.

As set forth in Advice 5173-E, SCE is not holding another VAMO process for 2027.¹⁹³

[REDACTED]

[REDACTED] SCE calculated the value of the RECs that were elected by parties during the 2024 Long-Term VA process (including by SCE and other LSEs) by multiplying the amount of GWh allocated by the RPS Adder, as shown on the RPS Adjustments tab of Appendix B. RECs sold as part of the 2024 Long-Term MO process were then assigned value based on the accepted bid price. All volumes not allocated in either VA or long-term MO processes are available to be used by SCE towards its 2027 RPS compliance target.

To determine the value of Actual Retained RPS, SCE evaluated its RPS compliance position, which is calculated as its compliance target (based on its bundled load forecast at the meter multiplied by its 2027 compliance target percentage) minus all RECs SCE owns and usage of banked RECs (if needed) and accounting for adjustments as part of the GTSR program. As part of the total F&PP RPS portfolio, SCE owns both PCIA and non-PCIA eligible (*e.g.*, Tree Mortality) RECs. Within the PCIA portfolio, not all RECs are eligible for the VAMO due to statutory limitations under Section 399.21(a)(4) of the California Public Utilities Code. These RECs were not made available to parties during the VAMO but are used by SCE towards RPS compliance.

Consistent with D.21-05-030 (the 2017 PCIA OIR Track 3 decision), SCE's VAMO process allowed parties to elect RECs from SCE's short- and long-term portfolio. In 2024, SCE and other counterparties elected both short- and long-term RECs based on their respective load share percentages. In 2027, SCE will not have a short-term MO process but will allocate any VA RECs from the contracts signed in 2024. For the PCIA indifference amount calculations, SCE developed a vintage-based snapshot of the long-term RECs elected by parties; any unallocated RECs were made available for the long-term MO process in 2024. [REDACTED]

¹⁹³ Advice 5173-E was approved by the Commission's Energy Division on May 8, 2024, with an effective date of May 1, 2024.

[REDACTED]

[REDACTED]

For context, SCE may “bank” RECs for bundled service customers that are generated in a given year but not needed for RPS compliance and not sold. Banked RECs may then be used (or “retired”) in later years if SCE is short of its RPS compliance requirements. For RECs generated and banked on January 1, 2019, or later (Post-2018 Banked RECs), the current PCIA methodology requires IOUs to assign a zero-dollar market value in the year the RECs are generated and banked.¹⁹⁵ Then, in a later year in which the IOU retires the RECs to satisfy its bundled service customers’ RPS compliance requirements, bundled service customers pay for those RECs at a price equal to the Final RPS Adder for that year.¹⁹⁶

¹⁹⁴ [REDACTED]

¹⁹⁵ D.19-10-001, p. 35.

¹⁹⁶ *Id.*, p 31.

1 In this October Update, SCE revised its banked REC quantities to incorporate the
2 California Energy Commission’s final verified results for Compliance Period 4 (2021–2024), released in
3 August 2026 [REDACTED]

4 [REDACTED]
5 [REDACTED]
6 Consistent with D.26-09-047, SCE will continue to apply a zero-dollar valuation to Pre-
7 2019 Banked RECs if such RECs are used for bundled service RPS compliance for the purposes of
8 calculating PCIA indifference amounts.¹⁹⁷

9 SCE’s approved 2025 RPS Plan authorizes SCE to procure short-term PCC-1 and PCC-3
10 RECs,¹⁹⁸ which, in addition to banked RECs and RECs generated from SCE’s portfolio of resources,
11 can be applied to help meet RPS compliance. SCE’s “usage order” for applying RECs to meet bundled
12 service RPS compliance obligations for 2027 PCIA forecast ratemaking purposes is as follows: First,
13 SCE uses purchased RECs, beginning with PCC-3 RECs, following by PCC-1 RECs. Second, SCE uses
14 RECs generated in the current year by SCE’s portfolio of resources. Finally, SCE uses banked RECs to
15 fill any remaining short position, prioritizing the use of Post-2018 Banked RECs before utilizing any
16 Pre-2019 Banked RECs. In summary, SCE’s current REC usage order for the purposes of 2027 PCIA
17 forecast ratemaking is:

- 18 1. Purchased PCC-3 RECs (in accordance with statutory limits and as set forth in
19 Appendix B);
- 20 2. Purchased PCC-1 RECs (in accordance with statutory limits and as set forth in
21 Appendix B);
- 22 3. RECs generated in the current year from SCE’s portfolio of resources;
- 23 4. Post-2018 Banked RECs;
- 24 5. Pre-2019 Banked RECs.

¹⁹⁷ D.26-09-047, OP 1.

¹⁹⁸ See *Southern California Edison Company’s (U- 338-E) Final 2025 Renewables Portfolio Standard (RPS) Procurement Plan*, Section XV, approved by D.25-12-025, filed on January 26, 2026 (R.24-01-017).

Purchased RECs are recorded as a debit to the applicable balancing account identified in the advice letter requesting authorization for the purchase. When these purchased RECs are used for bundled customer compliance, they will be treated in a manner consistent with Actual Retained RPS and valued using the applicable RPS MPB. A corresponding credit will be recorded to the originating balancing account identified in the advice letter,¹⁹⁹ and a debit will be recorded to the ERRA BA.

E. Recovery of Balancing and Memorandum Account Balances and UOS Separator Forecast Costs in CTC and PCIA Rates

The 2027 CTC and PCIA rates will reflect (1) the recovery of the 2026 year-end PABA balance; (2) the transfer of the 2026 year-end ERRA BA balance to the 2026 vintage subaccount of the PABA as directed in D.22-01-023;²⁰⁰ (3) the UOS Separator project; and (4) the continuation of the 24-month amortization of the General Rate Case Revenue Requirement Memorandum Account (GRCRRMA). Each is described below.

1. Recovery of the 2026 PABA Balance

SCE's PABA, which has subaccounts for each vintage portfolio, is used to record the actual costs, market revenues, Actual Retained RA and RPS Values (as calculated using the applicable Commission-adopted MPB values), and billed customer revenues associated with the CTC- and PCIA-eligible resources. The 2026 year-end PABA balance thus reflects the difference between the actual 2026 above-market costs of SCE's CTC-and PCIA-eligible portfolio and the amount collected from customers' CTC, PCIA and generation rates in 2026. Pursuant to D.18-10-019 and D.19-10-001, these year-end balances are then either recovered from or returned to customers in 2027 rates. Chapter X herein describes the methodology and inputs used by SCE to complete the 2026 PABA true-up.

SCE's current estimate of the 2026 year-end PABA balance is shown in Table 2 of Attachment A.

¹⁹⁹ For administrative ease, if the originating balancing account is the ERRA BA, SCE will not make an accounting entry as the debit and credit would cancel out.

²⁰⁰ See also Advice 4756-E.

1 **2. Transfer of the 2026 Year-End ERRA BA Balance**

2 In accordance with OP 4 of D.22-12-012, the 2026 year-end balance in the ERRA BA
3 will be transferred to the 2026 subaccount of the PABA. SCE's current forecast of the 2026 year-end
4 ERRA BA balance is thus included in the forecast 2027 revenue requirement for the 2026 subaccount of
5 the PABA.

6 **3. UOS Separator**

7 In accordance with Resolution E-5259, the UOS Separator project began counting
8 towards MTR procurement requirements, effective August 1, 2023.²⁰¹ Therefore, in accordance with
9 D.21-06-035 and Resolution E-5259, the costs and benefits of the Separator project are recovered via the
10 2021 subaccount of the PABA in 2027.

11 **4. 24-month Amortization of the GRCRRMA**

12 In Advice 5398-E, SCE established the GRCRRMA to track the difference between: (1)
13 the 2025 Test Year GRC base revenue requirement authorized by the Commission in D.25-09-030; and
14 (2) the currently authorized base revenue requirement. In accordance with D.25-09-030,²⁰² SCE has
15 included the recovery of the January 1, 2025 through September 30, 2025 balance in the GRCRRMA
16 that is to be collected in rates over a 24-month amortization period, from October 1, 2025, through
17 September 30, 2027.²⁰³

18 **F. Calculation of Final CTC and PCIA Rates**

19 Pursuant to D.18-10-019, the vintaged Indifference Amounts are allocated to rate groups using
20 the system generation revenue allocation factors,²⁰⁴ then are divided by the forecast billing determinants
21 to set the final PCIA rates. In accordance with D.19-10-001, SCE applied forecast **vintage-specific**

²⁰¹ See Advice 4928-E as approved by Resolution E-5259.

²⁰² D.25-09-030, OP 2.

²⁰³ *Id.*, OP 3.

²⁰⁴ The generation allocation factors used to allocate the vintaged Indifference Amounts were developed using **system-level** customer group load profiles, whereas the generation allocation factors used to allocate generation costs to bundled service customers were developed using bundled service customer group load profiles. The system-level generation allocation factors are used to allocate certain demand response incentive revenues. See Joint IOU Exhibit-01 in R.17-06-026, p. 4-65 and Table 2-B in Advice 3401-E.

1 billing determinants to set the final PCIA rates.²⁰⁵ These vintage-specific billing determinants
2 correspond directly with the forecast usage of all customers responsible for each vintage portfolio of
3 resources and are constructed using a combination of historical data for existing Departing Load
4 customers, based on their assigned vintage, and data for expected CCA departures/returns in 2026 and
5 2027. SCE applies 2025 and 2026 recorded usage as the basis to estimate the amount of load in each
6 vintage of Departing Load customers.

7 For example, Continuous DA customers plus Departing Load customers in SCE's 2001-2009
8 *customer vintages* total approximately 6,282 GWh. Those customers are not responsible for any of the
9 resources procured on or after January 1, 2010, because they departed prior to the procurement of those
10 resources. As such, the forecast billing determinants for the 2010 *vintage portfolio of resources* is equal
11 to the forecast system sales less 6,282 GWh (*i.e.*, the forecast sales for everyone except those who left
12 before those resources were procured). Similarly, customers in SCE's 2010 *customer vintage* are
13 forecasted to use approximately 1,590 GWh; their usage should be excluded from the forecast billing
14 determinants used for the 2011 *vintage portfolio of resources*. As such, the forecast billing determinants
15 for the 2011 *vintage portfolio of resources* is equal to the forecast system sales less 6,282 GWh
16 (Continuous DA, 2001-2009 vintage Departing Load), less 1,590 GWh (2010 *customer vintage*
17 Departing Load). This arithmetic calculation is detailed in the workpapers supporting this chapter.

18 It should be noted that a mismatch is created by using the generation allocation factors at the
19 system level (developed based on rate group sales of all customers on the system) to allocate the
20 vintaged Indifference Amounts to rate groups and the use of forecast billing determinants by vintage to
21 calculate the incremental vintaged PCIA rates. To eliminate this mismatch, the authorized generation
22 allocation factors must be adjusted (normalized) to the forecast rate group sales by vintage.²⁰⁶ This is
23 accomplished by first calculating a marginal cost revenue responsibility,²⁰⁷ on a cent/kWh basis for each

²⁰⁵ See D.19-10-001, OP 6. CTC rates are set using system billing determinants.

²⁰⁶ The greatest difference occurs in the standby class of customers where the GRC Phase 2 system level allocation factors only represent the contribution of backup load, while the sales forecast for the standby class represents the backup and supplemental loads.

²⁰⁷ The marginal cost revenue responsibility is determined in the most recent approved GRC Phase 2 proceeding.

rate group based on the authorized generation allocations factors and then multiplying it by the forecast kWh usage by vintage to develop normalized generation allocation factors that account for the difference between the rate group kWh usage at the system level and rate group kWh usage by vintage.

G. Other Proceedings or Filings That May Impact the 2027 CRS

SCE is currently aware of the following regulatory proceedings and/or filings could have an impact on the final 2027 CRS rates proposed herein, as described below.

1. Applications for the Sale of Various Hydroelectric Plants

On August 28, 2024, SCE filed A.24-08-012, which seeks Commission approval for the sale of SCE's Mill Creek 1, Mill Creek 3, Ontario 1, Ontario 2, Santa Ana River 1 & 3, and Sierra hydroelectric (Hydro) power plants and associated generating facilities to San Bernardino Valley Municipal Water District. These projects have an aggregate capacity of 11.64 MW. On September 18, 2025, the Commission adopted D.25-09-012 granting SCE's request. With the sale having closed on September 14, 2026, SCE expects to submit its final implementation advice letter on or before November 13, 2026.²⁰⁸

On March 4, 2025, SCE filed A.25-03-001 to sell its Lower Tule Hydroelectric Power Plant and associated generation facilities, with a capacity of 2.52 MW located near Springville, CA. The Project has not been operational since 2017 due to damage to the water conveyance flowline caused by the Pier Fire. On August 13, 2026, the CPUC adopted D.26-08-014, which authorized the sale of the Lower Tule Hydroelectric Plant. SCE expects to submit the final implementation advice letter in December 2026, but the sale has not officially closed yet.²⁰⁹

As explained in Section IV.E.1., SCE has reduced its energy and capacity forecast for these sales.

²⁰⁸ See D.25-09-012, OP 4, which orders SCE to submit a Tier 1 Advice Letter containing the final calculation of the loss-on-sale and tax information related to the sale of the facilities within 60 days of the closing date of the Asset Purchasing Agreement.

²⁰⁹ See D.26-08-014, OP 6, which orders SCE to submit a Tier 1 Advice Letter containing the final calculation of the loss-on-sale and tax information related to the sale of the facilities within 60 days of the closing date of the Asset Purchasing Agreement.

1 **2. 2027 Post-Test Year Advice Letter**

2 Before December 1, 2026, SCE will submit a 2027 Post-Test Advice Letter in accordance
3 with the 2025 GRC Decision. The adopted Post-Test Year Ratemaking (PTYR) mechanism would
4 adjust SCE’s Authorized Base Revenue Requirement (ABRR) on an annual basis, in between GRC Test
5 Years. This would include an update to the 2027 AGBRR that SCE would use in its implementation of
6 the 2027 ERRA Forecast rates.

7 **3. 2027 Uncollectibles Factor**

8 Pursuant to D.25-09-030,²¹⁰ SCE expects to submit a Tier 1 Advice Letter in
9 October/November 2026 to update its Uncollectibles Factor for 2027. Using the methodology adopted
10 in D.25-09-030, SCE will present the uncollectibles factor using a ten-year average of recorded write-
11 offs. SCE will incorporate the new Uncollectibles Factor in its 2027 ERRA Forecast Implementation
12 Advice Letter.

13 **H. Master Data Request Workpapers and Confidentiality Designations**

14 **1. Master Data Request Workpapers**

15 In accordance with OP 11 of D.22-01-003, OP 5 of D.22-01-023 and consistent with
16 responses to a master data request, SCE is concurrently including in its workpapers to this filing the final
17 workpapers supporting the PCIA rates approved with the prior year’s ERRA Forecast proceeding. The
18 2026 ERRA Forecast “final” PCIA workpapers are identical to the workpapers submitted with Advice
19 5717-E, which implemented SCE’s 2026 ERRA Forecast final decision and reflect the PCIA rates
20 currently in effect.²¹¹ Additionally, SCE has provided the ERRA Activity Reports submitted to the
21 Commission for the months of January through September to parties. SCE will supplement these reports
22 within 5 business days after each subsequent monthly report is submitted to the Commission.²¹² Access
23 to the confidential versions of these workpapers is subject to the Commission’s existing confidentiality

²¹⁰ D.25-09-030, p. 460.

²¹¹ Pursuant to OP 11 of D.22-01-003, the Commission will not revisit the prior year’s PCIA rates based on the incorporation of the prior year’s final PCIA workpapers in the evidentiary record of a pending ERRA forecast proceeding.

²¹² D.22-01-023, OP 5.

1 rules and regulations and will only be provided upon execution of the applicable non-disclosure
2 agreements.

3 **2. Confidentiality Designations**

4 On April 18, 2022, in accordance with OP 7 of D.22-01-023, SCE participated in a meet
5 and confer with parties to its 2022 ERRR forecast proceeding to discuss the application of D.06-06-066
6 to designations of ERRR and PABA monthly report data and PCIA workpaper data as public or
7 confidential.²¹³ Pursuant to discussions during the meet and confer, SCE agreed to designate the
8 following resource attributes in its PCIA workpapers, which were previously designated as confidential
9 or not included, as public on a going-forward basis: resource name, resource CAISO ID, internal
10 resource identifier, resource technology, location, contract type, counterparty, contract execution date,
11 commercial operation date, contract expiration date, cost recovery mechanism, PCIA vintage and RPS
12 eligibility. SCE will include these resource attributes in the submission of any public workpapers.

²¹³ PG&E and San Diego Gas & Electric Company (SDG&E) were also present at this meet and confer.

X.

UPDATED 2026 COST RESPONSIBILITY SURCHARGE TRUE-UP

A. Overview

This chapter describes the methodology and inputs used to “true up” the 2026 CRS, in accordance with the methodology adopted in D.18-10-019 and refined in D.19-10-001, D.25-06-049, and D.26-09-047.

B. Background

On October 1, 2018, the Commission adopted D.18-10-019 which, in part, ordered an annual true-up of PCIA and CTC rates to reflect actual values realized in market transactions related to the PABA portfolio’s Energy Value.²¹⁴ To effectuate this true-up process, SCE submitted Advice 3914-E on December 10, 2018 to establish the PABA, with subaccounts for each vintage portfolio, and to modify its other generation-related balancing accounts.²¹⁵ Pursuant to D.18-10-019, the above-market costs of the PABA resources are forecast annually in SCE’s ERRA forecast proceeding and recovered, on a *forecast* basis, from bundled service customers through their generation rates and from Departing Load customers through their PCIA and CTC rates. *Actual* billed customer revenues, resource costs, market revenues realized in the CAISO markets and bilateral transactions, and Actual Retained RA and RPS values²¹⁶ from the PABA portfolio are then recorded in the PABA throughout the year, with any year-end under- or over-collected balance recovered in customer rates the following year.

On October 10, 2019, the Commission adopted D.19-10-001 to further refine the true-up process described above. Specifically, the Commission adopted a process for truing up the RA and RPS components of the MPB, in addition to the Energy Value true-up (which was not modified), and specified that this true-up should occur as part of the ERRA forecast proceeding.²¹⁷

On June 26, 2025, the Commission adopted D.25-06-049, which adopted changes to the calculation of the RA MPB. Specifically, D.25-06-049 (1) consolidates the system, local, and flexible RA MPBs into a single RA MPB and (2) removes affiliate, swap, and duplicative sleeve transactions from the calculation.²¹⁸ D.25-06-049 also orders the use of three-years’ transaction data when adopting the annual forecast RA MPB and four-years’ transaction data when adopting the annual final RA MPB.²¹⁹

²¹⁴ D.18-10-019, OP 6.

²¹⁵ On May 3, 2019, the Commission’s Energy Division approved Advice 3914-E, with a January 1, 2019 effective date.

²¹⁶ The Actual Retained RPS and RA values that are recorded as a credit in the PABA correspond with debit entries in the ERRA BA and other applicable cost recovery accounts for those RPS and RA attributes.

²¹⁷ D.19-10-001, OPs 3 and 4.

²¹⁸ D.25-06-049, OP1.

²¹⁹ *Id.*

On September 17, 2026, the Commission adopted D.26-09-47, which affirmed the valuation of Pre-2019 Banked RECs at \$0 for PCIA ratemaking purposes. OP 2 required that “the methodology adopted in this decision shall be effective immediately and shall be incorporated into each investor owned utility’s 2027 Energy Resource Recovery Account October Updates, impacting 2026 true-ups and 2027 forecasted rates.” For the RPS true-up and PCIA ratemaking purposes, SCE’s usage order for applying RECs to meet bundled service customers’ RPS compliance obligations is the same as detailed in Chapter IX.D.3. above.

In summary, for the RPS and RA Value true-ups, the Commission adopted the methodologies shown in Table X-47 and Table X-48, respectively, with the Final RPS and RA Adders provided by the Commission’s Energy Division by the first business day of October each year.²²⁰

Table X-47
RPS Value True-Up Methodology

Type of RPS Product	Price	Quantity
Actual Retained ¹ (Non-Banked RECs)	Final RPS Adder, as calculated by the Energy Division	Volume used for IOU compliance from PABA-eligible Portfolio
Actual Retained (Post-2018 Banked RECs)	Final RPS Adder, as calculated by the Energy Division	Volume used for IOU compliance from PABA-eligible Portfolio
Actual Retained (Pre-2019 Banked RECs)	\$0	Volume used for IOU compliance from PABA-eligible Portfolio
Actual Sold	Actual transacted prices	Actual transacted volume
Actual Unsold	\$0	Actual unsold volume

¹ Includes any purchased RECs that are used for RPS compliance.

Table X-48
RA Value True-Up Methodology

Type of RA Product	Price	Quantity
Actual Retained	Final RA Adder, as calculated by the Energy Division	RA used for compliance and the amounts retained for IOU use
Actual Sold	Applicable actual transacted prices	Applicable actual transacted volume
Actual Unsold	\$0	Quantity offered for sale but not sold or used by the IOU

C. 2026 Market Price Benchmarks

Table X-49 has been updated to include the 2026 Final MPBs provided by the Commission’s Energy Division on October 1, 2026. The 2026 Final MPBs are used to true-up the RPS and RA Values.

²²⁰ See OP 1 of D.22-01-023, which moved the release of the Final Adders to the first business day of October (instead of November).

1 There is no Final Energy Index used in the true-up process, since revenue is trued up for 2026 based on
2 the realized (actual) net CAISO revenues for all PABA-eligible resources.

Table X-49
Comparison of 2026 Forecast MPBs to 2026 Final MPBs

Market Price Benchmark (MPB)	2026 Forecast Adders (In Rates)	2026 Final Adders (October 2026)	% Change
Energy Index	\$40.00/MWh	N/A (use actuals)	N/A
RPS Adder	\$62.45/MWh	\$30.88/MWh	-51%
RA Adder	\$138.36/kW-yr	\$121.32/kW-yr	-12%

3 **D. 2026 PABA Year-End Balance and Variance Analysis**

4 The PABA records the difference between actual above-market costs and actual customer
5 revenues. Actual costs, market revenues, and imputed revenues are recorded to the PABA based on the
6 operation of the resources in SCE's PABA portfolio. Billed revenues received from customers (*i.e.*, the
7 product of actual kWh consumed by the approved ERRR Forecast rates) are recorded to the PABA
8 based on actual customer usage. When the actual above-market costs exceed the actual billed customer
9 revenues, an under-collection results. Alternatively, if the actual above-market costs are less than the
10 actual billed customers revenues, the PABA will show an over-collection.

11 Table X-50 shows the forecast year-end balance in the PABA for 2026,²²¹ by vintage, using the
12 updated inputs described herein. January through September are based on recorded actuals, while
13 October through December remain based on a forecast.

²²¹ Table X-50 does not reflect the amortization of the GRCRRMA.

Table X-50
Updated Forecast 2026 Year-End PABA Balance by Vintage
(\$000)

[illegible]

1 SCE is now forecasting a 2026 year-end PABA under-collection balance of \$1,460.677
2 million.²²² This amount—by resource vintage—is included in the forecast 2027 PCIA revenue
3 requirement included in Appendix B. SCE compared recorded actuals and the projected year-end
4 balances by category to the approved 2026 forecast to determine the key drivers contributing to the
5 forecasted year-end under-collection balance in the PABA. The shift to a much larger under-collection
6 is primarily the result of the true-up of Actual Retained RPS using the 2026 Final MPB and lower than
7 forecast recorded CAISO market revenues.

8 The results are further summarized in Table X-51 and discussed in the following sections.

²²² \$1,465.028 million when including the gross up for Uncollectibles.

Table X-51
2026 YE PABA Under-Collection Variance Analysis

Line No.	Category	2026 PCIA Forecast (\$000)	2026 YE Projection (\$000)	Variance (\$000)	Variance %
1	AGBRR	\$ 907,762	\$ 907,762	\$ 0	0.00%
2	Fuel, Contracts, Other Costs	\$ 3,593,132	\$ 3,457,155	\$ (135,977)	-3.78%
3	Total Portfolio Costs	\$ 4,500,894	\$ 4,364,917	\$ (135,977)	-3.02%
4	Energy Value	\$ (1,426,661)	\$ (1,047,359)	\$ 379,303	-26.59%
5	Forecast/Actual Retained RPS	\$ (1,698,176)	\$ (1,072,207)	\$ 625,970	-36.86%
6	RPS True-Up	\$ -	\$ 360,025	\$ 360,025	N/A
7	Forecast/Actual Sold RPS	\$ (285,398)	\$ (110,719)	\$ 174,680	-61.21%
8	RPS Value	\$ (1,983,575)	\$ (822,900)	\$ 1,160,675	-58.51%
9	Forecast/Actual Retained RA	\$ (1,322,937)	\$ (1,451,811)	\$ (128,874)	9.74%
10	RA True-Up	\$ -	\$ 159,195	\$ 159,195	N/A
11	Forecast/Actual Sold RA	\$ (130,633)	\$ (51,166)	\$ 79,467	-60.83%
12	RA Value	\$ (1,453,570)	\$ (1,343,783)	\$ 109,788	-7.55%
13	Total Market Value	\$ (4,863,806)	\$ (3,214,041)	\$ 1,649,765	-33.92%
14	Indifference Amount	\$ (362,912)	\$ 1,150,876	\$ 1,513,788	417.12%
15	Misc Adjustments / Bilateral Sales	\$ 1,375	(8,916)		
16	Adj PCIA Revenue Requirement	\$ (361,537)	\$ 1,141,961	\$ 1,503,497	415.86%
17	Customer Revenues	(202,924)	(197,753)	\$ 5,171	-2.55%
18	Subtotal Under/(Over) Recovery	\$ (564,461)	\$ 944,208	\$ 1,508,668	
19	2025 PABA Year-End Balance	\$ 1,311,242		\$ (1,311,242)	
20	2025 ERRR BA YE Balance Transfer	\$ (776,464)		\$ 776,464	
21	UOS Separator	\$ 29,682			
22	Total Under/(Over) Recovery	\$ (0)	\$ 944,208	\$ 944,208	
23	2026 PABA				
24	Beginning Balance		\$ 1,420,831		
25	Activity		\$ 944,208		
26	Beginning and Ending Month Adjustments ²		\$ (935,881)		
27	GRC Memo Account Adjustment		\$ (39,576)		
28	Interest		\$ 31,519		
29	Ending Balance		\$ 1,421,100		

1 **1. True-Up of Customer Revenues**

2 SCE implemented its 2026 ERRA Forecast revenue requirement in rates on January 1,
3 2026, which included an authorized PABA forecast amount of \$2,720.126 million.²²³ This included the
4 2026 forecast fuel and purchased power costs of \$1,495.606 million and the 2025 year-end PABA
5 balance under-collection of \$1,224.521 million. [REDACTED]

6 [REDACTED]

7 [REDACTED]²²⁴

8 **2. True-Up for Total Portfolio Costs**

9 Total portfolio costs are projected to be approximately three percent lower than forecast.
10 This is primarily the result of lower fuel costs from lower-than-forecast dispatch from SCE's UOG gas
11 units and lower costs from SCE's procured RA contracts, translating into approximately [REDACTED]
12 [REDACTED] of lower-than-forecast costs.

13 **3. Energy Value True-Up**

14 Energy revenues are "trued up" to reflect actual values realized in the CAISO (and other
15 forward) sales of energy, if any through the operation of the PABA. Based on the Commission-
16 prescribed 2026 Energy Index for SCE of \$40.00/MWh, SCE forecast to receive approximately \$1.427
17 billion in energy revenues and set its PCIA rates accordingly for 2026. However, based on 2026 market
18 actuals through September and a forecast for October through December, SCE is projecting \$1.047
19 billion in CAISO market revenues, which is 27 percent lower than the amount used to set rates. As
20 shown in Table X-52, the actual weighted average day-ahead market revenues from SCE's PABA
21 portfolio were only \$21.02/MWh, which is significantly lower than the \$40.00/MWh used to set rates.

²²³ See Advice 5717-E.

²²⁴ Historically, customer revenues are shown as a negative value in a balancing account. However, for 2026, because specific vintages of PCIA rates were negative, the customers with those vintages were receiving a credit.

Table X-52
Actual Weighted Average Day-Ahead Market Revenues from SCE's PABA
Portfolio of Resources

January through August 2026	
PABA Resource Technology	Weighted Average Day-Ahead Market Revenue (\$/MWh)
Gas	\$56.91
Battery	\$37.83
BioGas/BioMass	\$27.93
Hydroelectric	\$26.17
Wind	\$25.28
Nuclear	\$27.78
Geothermal	\$11.36
Solar	\$12.53
Other	\$22.82
Overall	\$21.02

Note: The 2026 Forecast Energy Index MPB used to set 2026 PCIA rates was **\$40.00/MWh**.

4. RPS Value True-Up

The RPS Value True-Up involves three components: Retained, Sold, and Unsold RPS. Table X-53 provides a comparison of Forecast Retained RPS to Actual Retained RPS,²²⁵ a comparison of Forecast and Actual Sold RPS to Actual Sold RS, and a comparison of Forecast Unsold RPS to Actual Unsold RPS.

²²⁵

Table X-53
2026 Forecast RPS Value Inputs

RPS Product Categories	2026 Forecast		
	Price (\$/MWh)	Quantity (GWh)	Value (\$000)
Forecast Retained RPS			
REC's that Cannot be Allocated ¹	\$62.45		
Voluntary Allocation (SCE Portion)	\$62.45		
Purchased RECs (PCC-1) ²	\$62.45		
Purchased RECs (PCC-3) ²	\$62.45		
Banked RECs (post-2018)	\$62.45		
Banked RECs (pre-2019)	\$0.00		
Non-SCE Voluntary Allocation	\$62.45		
RPS Sold through Market Offers (Long-Term)	Actual prices for sales up to 45 days prior to ERRA Forecast filing		
Actual Sold RPS	Actual prices for sales up to 45 days prior to ERRA Forecast filing		
Forecast Unsold	\$0.00		
Forecast Retained + Forecast/Actual Sold			

Areas shaded in gray are confidential per D.06-06-066, Matrix section V.C.

¹ Includes CREST, Re-MAT, Bio-MAT, GTSR, etc.

² For the May Filing, SCE utilized its 2026 ERRA Forecast, which did not contemplate use of Purchased RECs.

RPS Product Categories	2026 Final ³		
	Price (\$/MWh)	Quantity (GWh)	Value (\$000)
Actual Retained RPS			
REC's that Cannot be Allocated ¹	\$30.88		
Voluntary Allocation (SCE Portion)	\$30.88		
Purchased RECs (PCC-1) ⁴	\$30.88		
Purchased RECs (PCC-3) ⁴	\$30.88		
Banked RECs ⁵ (post-2018)	\$0.00		
Banked RECs (pre-2019)	\$0.00		
Non-SCE Voluntary Allocation	\$30.88		
RPS Sold through Market Offers	Actual prices for sales up to 45 days prior to ERRA Forecast filing		
Actual Sold RPS	Actual prices for sales up to 45 days prior to ERRA Forecast filing		
Actual Unsold	\$0.00		
Forecast Retained + Forecast/Actual Sold			

Areas shaded in gray are confidential per D.06-06-066, Matrix section V.C.

³ Based on recorded actuals through September and a forecast for October through December.

1 Despite SCE's projected 2026 year-end RPS quantity projected to be approximately at
2 forecast, the year-end RPS Value is approximately 57 percent lower than the forecast RPS Value. This
3 is primarily the result of applying the lower Final RPS Adder and the current projected use of Purchased
4 PCC-1 and PCC-3 RECs in 2026. SCE will not record a separate accounting entry when Purchased
5 RECs, that have their original contract costs recovered through the ERRA BA, are used for RPS
6 compliance. This is because it would result in an offsetting debit and a credit to the ERRA BA. For
7 transparency, SCE has included the total quantity of Purchased PCC-1 and PCC-3 RECs that it forecasts
8 to use for RPS compliance in 2026, but only reflected the value of the Purchased RECs that have their
9 initial cost recovery through the 2025 subaccount of PABA.²²⁶

10 **5. RA Value True-Up**

11 The RA Value True-Up involves three components: Retained, Sold, and Unsold RA.
12 Table X-54 provides a comparison of Forecast Retained RA to Actual Retained RA, a comparison of
13 Forecast and Actual Sold RA to Actual Sold RA, and a comparison of Forecast Unsold RA to Actual
14 Unsold RA.

²²⁶ Because SCE's REC positions and the resulting impacts to the applicable PABA subaccounts remain subject to change, SCE is using a simplified forecasting approach to estimate the potential impact. The final accounting impact will be calculated based on the positions ultimately adopted and reflected as part of SCE's implementation advice letter.

Table X-54
2026 Forecast RA Value

RA Product Categories	2026 Forecast		
	Price (\$/kW-yr)	Quantity (MW)	Value (\$000)
Forecast Retained RA	(intentionally left blank)		
System	\$138.36		
Local	\$138.36		
Flexible	\$138.36		
Excess RA	(intentionally left blank)		
	Actual prices for sales up to 45 days prior to ERRA Forecast filing		
Actual Sold RA ¹			
Forecast Sold RA	(intentionally left blank)		
System ²	\$138.36		
Local	\$138.36		
Flexible	\$138.36		
Forecast Unsold	\$0		
Forecast Retained + Forecast/Actual Sold			

Areas shaded in gray are confidential per D.06-06-066, Matrix section V.C.

¹ SCE includes revenue from RA swaps in this category (see Appendix B workpapers) but swaps are not reflected in the Quantity column.

² Includes additional amount to meet the 18 percent planning reserve margin (see Appendix B workpapers).

RA Product Categories	2026 Final ³		
	Price (\$/kW-yr)	Quantity (MW)	Value (\$000)
Actual Retained RA	(intentionally left blank)		
System	\$121.32		
Local	\$121.32		
Flexible	\$121.32		
Excess RA	(intentionally left blank)		
	Actual prices for sales up to 45 days prior to ERRA Forecast filing		
Actual Sold RA ¹			
Forecast Sold RA	(intentionally left blank)		
System ²	\$121.32		
Local	\$121.32		
Flexible	\$121.32		
Forecast Unsold	\$0		
Forecast Retained + Forecast/Actual Sold			

³ Based on recorded actuals through September and a forecast for October through December.

1 SCE's projected 2026 year-end RA Value is estimated to be approximately 8 percent
2 lower than forecast. This is primarily the result of the application of the 2026 Final RA Adder, partially
3 offset by higher overall retained volumes and lower sold RA.

4 **6. Forecasted Year-End Transfers in PABA**

5 On May 12, 2023, SCE filed A.23-05-010, its 2025 GRC. D.25-09-030 approved Phase
6 1 of SCE's 2025 GRC. On September 30, 2025, SCE submitted Advice 5642-E implementing the
7 ratemaking mechanisms in accordance with D.25-09-030.

8 a) Palo Verde Non-Labor Operations and Maintenance Expense Balancing Account

9 D.25-90-030 authorized the establishment of the two-way Palo Verde Non-Labor
10 Operations and Maintenance (O&M) Expense Balancing Account (PVNLOMBA) to record both actual
11 Palo Verde operating costs and authorized funding related to Palo Verde non-labor O&M expenses.
12 Cost recovery is automatic for up to 110 percent of the authorized amounts in any year.²²⁷ Cost
13 recovery for amounts in excess of 110 percent of the authorized amounts will be subject to
14 reasonableness review in SCE's next GRC. SCE will transfer, on an annual basis, any under-collection,
15 up to the 110 percent cap, or over-collection recorded in the PVNLOMBA as of December 31 to the
16 Legacy UOG subaccount of the PABA to be recovered from or returned to customers the following
17 year.²²⁸ For 2026, SCE forecasts the PVNLOMBA will record costs of \$126.400 million, which
18 exceeds the 110 percent threshold and SCE has forecasted a December 2026 transfer of \$11.401 million
19 to the Legacy UOG subaccount of the PABA for 2026. SCE will update this amount as necessary in its
20 ERRRA Forecast Implementation Advice Letter. On December 31, 2026, SCE will transfer the actual
21 recorded amount²²⁹ to the Legacy UOG subaccount of the PABA.

²²⁷ D.25-09-030, OP 21. See Preliminary Statement Part XXXX (PVNLOMBA) for the annual authorized revenue requirement. For 2026, the authorized PVNLOMBA revenue requirement is \$114.006 million (\$115.421 million with FF&U). The 2026 authorized PVNLOMBA revenue requirement will be set in the 2026 PTYR Advice Letter.

²²⁸ *Id.*

²²⁹ Under-collection amount equals the amount above the 100 percent authorized and under the 110 percent cap.

b) Continuation of Post-Employment Benefits Other than Pensions Cost Balancing Account, Pension Costs Balancing Account, and Medical Programs Balancing Account

D.25-09-030 also approved the continuation of the existing two-way Post Employment Benefits Other than Pensions Balancing Account (PBOPBA), Pension Costs Balancing Account (PCBA), and Medical Programs Balancing Account (MPBA) through the 2025 GRC cycle and the modification of the schedule for transferring the year-end PBOPBA, PCBA, and MPBA balances to the BRRBA and PABA to occur in December instead of January the following year.²³⁰

SCE has forecasted December 2026 transfers of -\$1.879 million, -\$0.928 million, and \$7.337 million for the PBOPBA, PCBA, and MPBA, respectively, to PABA. SCE will update this amount as necessary in its ERRRA Forecast Implementation Advice Letter. On December 31, 2026, SCE will transfer the actual 2026 recorded amount to the PABA.

²³⁰ D.25-09-030, Section 39.1.8, 39.1.9, and 39.1.10.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26

XI.

UPDATED PRESENT RATE REVENUES

A. Present Rate Revenue

The average rates contained herein reflect the estimated 2027 ERRRA rate forecast by class and functional rate component. The average rates are estimated by applying the current revenue requirement, as of October 1, 2026, in addition to the 2027 ERRRA Forecast-related revenue changes, as proposed herein, to the forecast sales by class. A column has been added to Table XI-57 that illustrates the percentage change of the average rates over current October 1, 2026 rate levels.²³¹

The requested revenue requirement shown in Table II-2, comparing the 2027 ERRRA Forecast revenue requirement to the 2026 ERRRA Forecast revenue requirement, shows an overall decrease of \$200.798 million (\$3.532 million increase related to generation service and \$204.329 million decrease related to delivery service). The estimated bundled generation customer rates are decreasing by approximately 7.36 percent as indicated in Table XI-58, from 10.15 to 9.40 cents/kWh. This is because the decreased RA and RPS MPBs result in (i) an under-collection in the PABA, which is borne by both bundled service and departing load customers, and (ii) an over-collection in the ERRRA BA, which is credited solely to bundled service customers. Thus, the lower RA and RPS MPBs put downward pressure on bundled rates when accounting for cost responsibility allocation across all customers (i.e., bundled service and departing load customers).

Departing load rates are increasing because of the interaction between the ERRRA BA and PABA revenue changes for bundled service and departing load customers. ERRRA BA-related F&PP costs and the 2026 YE ERRRA BA balance, shown on lines 3 and 6 of Table II-3, reflect a forecasted *decrease* of approximately \$893.272 million. By contrast, PABA-related F&PP costs and the 2026 YE PABA balance, shown on lines 4 and 7 of Table II-3, reflect a forecasted *increase* of approximately \$900.657 million. ERRRA BA-related revenue requirements affect only bundled service customers, while PABA-related revenue requirements are shared between bundled service and departing load customers. As a result, increases in PABA-related cost responsibility increase PCIA rates. However, bundled customer

²³¹ See OP 7 of D.20-12-035.

1 generation rates also reflect a decrease in the ERRA BA-related revenue requirements that put
2 downward pressure on the rates.

3 The rate information is limited to the proposed revenue changes in this proceeding and does not
4 reflect the entirety of the consolidated revenue requirement changes SCE expects to implement during
5 the first quarter (Q1) of 2027.²³²

6 **B. Affordability Metrics**

7 On December 18, 2025, the Commission adopted D.25-12-044, *Decision Updating Affordability*
8 *Framework and Closing Proceeding*, updating the requirements for use of availability metrics in
9 proceedings. Pursuant to OP 1, affordability metrics are only required in GRC Phase 1 applications
10 where the revenue is estimated to exceed one percent of currently authorized revenues system-wide for a
11 single fuel. Therefore, SCE is not providing affordability metrics in its ERRA Forecast applications.

12 **C. Updated MCAM Rates**

13 Pursuant to D.23-11-094,²³³ SCE is providing updated usage amounts and the calculation of its
14 2027 forecast MCAM rates, as shown in Table XI-55.

²³² The Q1 2027 consolidated rate change will include other proceedings' approved revenue requirements, such as the FERC base transmission and GRC post-test year attrition revenue approved adjustment, that can potentially result in substantive changes to the average rates shown below.

²³³ See D.23-11-094, pp. 46-47.

Table XI-55
Updated 2027 Forecast MCAM Rates

Rate Class	12 CP Allocator (%)	Average Annual Usage Sept 2024-Aug 2026 (Mwh)	Estimated Annual Allocated Revenue Requirement	Rate (\$/kWh)
Domestic	0.46%	14,987	\$22,010	\$0.00147
GS-1	1.11%	51,355	\$53,050	\$0.00103
GS-2	18.73%	761,777	\$892,325	\$0.00117
TOU-GS-3	14.84%	643,714	\$706,971	\$0.00110
TOU-8-Sec (Standby & Non-Standby)*	22.31%	1,223,762	\$1,062,700	\$0.00087
TOU-8-Pri (Standby & Non-Standby)*	22.71%	1,190,750	\$1,081,902	\$0.00091
TOU-8-Sub (Standby & Non-Standby)*	19.42%	984,314	\$925,045	\$0.00094
TOU-PA*	0.26%	21,089	\$12,395	\$0.00059
St. Lighting*	0.16%	10,007	\$7,801	\$0.00078
TOTAL	100.00%	4,901,756	\$4,764,199	\$0.00097

* The standby and non-standby Large Power groups, TOU-PA-2 and TOU-PA-3 groups, and the Street Lighting and TC-1 rate groups have been combined in this table for illustrative purposes to comply with the CPUC's 15/15 confidentiality rule.

Table XI-56
Updated SCE's 2027 ERRR Forecast Class Average Rates (Bundled) Including GHG Climate Credit

Updated SCE 2027 ERRR Forecast Class Average Rates (Bundled)													
Line No.	Rate Schedule By Customer Group	Transmission (\$/kW)	Distribution w/ GHG (\$/kW)	NOCC (CAM) (\$/kW)	NCC (\$/kW)	PPCC (\$/kW)	DWR w/ L237RLE (\$/kW)	PPCCP (\$/kW)	LG (\$/kW)	Total Delivery (\$/kW)	Total Generation (\$/kW)	Total w/ PUCRB (\$/kW)	Percent Change Over Oct 2026 %
1	Domestic												
2	D	0.02481	0.21871	0.00723	0.00000	0.01112	0.00398	0.00100	0.10361	0.23882	0.10361	0.37243	-3.9%
3	D-CARE	0.02481	0.08273	0.00723	0.00000	0.01169	-	0.00100	0.10361	0.10361	0.10361	0.21111	-4.1%
4	DE	0.02481	0.11578	0.00723	0.00000	0.00929	0.00398	0.00100	0.10313	0.14607	0.10313	0.25460	-3.9%
5	DM	0.02481	0.07700	0.00723	0.00000	0.01127	0.00398	0.00100	0.10402	0.12027	0.10402	0.22529	-3.8%
6	DM-1	0.02481	0.23730	0.00723	0.00000	0.01422	0.00398	0.00100	0.10402	0.24733	0.10402	0.35133	-4.7%
7	DM-1-1	0.02481	0.23730	0.00723	0.00000	0.01422	0.00398	0.00100	0.10402	0.24733	0.10402	0.35133	-4.7%
8	DM-1-2	0.02481	0.20883	0.00723	0.00000	0.01197	0.00398	0.00100	0.10401	0.22466	0.10401	0.33883	-4.3%
9	DM-1-3	0.02481	0.18790	0.00723	0.00000	0.01131	0.00400	0.00100	0.10362	0.21190	0.10362	0.31912	-4.8%
10	Group Total												
11	Lighting Small Med Power												
12	GS-1	0.01777	0.11880	0.00508	0.00000	0.00896	0.00398	0.00100	0.10066	0.17788	0.10066	0.27814	-3.9%
13	GS-2	0.01844	0.14291	0.00494	0.00000	0.00908	0.00398	0.00100	0.10064	0.20233	0.10064	0.30287	-3.8%
14	TC-1	0.01289	0.22779	0.00383	0.00000	0.01016	0.00398	0.00100	0.09313	0.26661	0.09313	0.31386	-2.3%
15	TC-2	0.01738	0.14680	0.00494	0.00000	0.00783	0.00398	0.00100	0.08113	0.17783	0.08113	0.26298	-2.8%
16	TC-3												
17	Group Total												
18	Group Total	0.03864	0.12111	0.00489	0.00000	0.00873	0.00398	0.00100	0.09863	0.19010	0.09863	0.28813	-3.2%
19	Large Power												
20	TOU-4-S	0.03863	0.11790	0.00428	0.00000	0.00723	0.00398	0.00100	0.08668	0.12523	0.08668	0.23803	-3.2%
21	TOU-4-P	0.03323	0.10340	0.00417	0.00000	0.00610	0.00398	0.00100	0.08211	0.11321	0.08211	0.21442	-3.3%
22	TOU-4-T	0.00811	0.00000	0.00472	0.00000	0.00417	0.00398	0.00100	0.07727	0.09437	0.07727	0.17372	-4.2%
23	TOU-4-S-S	0.01771	0.12546	0.00771	0.00000	0.00712	0.00398	0.00100	0.08483	0.09437	0.08483	0.24099	-2.9%
24	TOU-4-S-P	0.00903	0.10620	0.00108	0.00000	0.00640	0.00398	0.00100	0.08030	0.12965	0.08030	0.21038	-3.2%
25	TOU-4-S-T	0.00718	0.02341	0.00090	0.00000	0.00414	0.00398	0.00100	0.07232	0.04388	0.07232	0.13106	-4.8%
26	Group Total												
27	Group Total	0.01687	0.07448	0.00387	0.00000	0.00583	0.00398	0.00100	0.07963	0.10259	0.07963	0.18174	-3.8%
28	Agricultural & Pumping												
29	TOU-PN-1	0.01387	0.12809	0.00421	0.00000	0.00799	0.00398	0.00100	0.09390	0.14221	0.09390	0.25011	-3.3%
30	TOU-PN-2	0.01296	0.10488	0.00378	0.00000	0.00641	0.00398	0.00100	0.07312	0.13419	0.07312	0.20738	-3.1%
31	TOU-PN-3												
32	Group Total	0.03332	0.11632	0.00388	0.00000	0.00716	0.00398	0.00100	0.08293	0.14742	0.08293	0.23033	-3.2%
33	Power & Area Lighting												
34	LS-1	0.01170	0.77282	0.00551	0.00000	0.01171	0.00398	0.00100	0.07314	0.74823	0.07314	0.79667	-0.8%
35	LS-2	0.01170	0.18629	0.00551	0.00000	0.01171	0.00398	0.00100	0.07307	0.21440	0.07307	0.28752	-1.9%
36	LS-3	0.01170	0.07938	0.00551	0.00000	0.01171	0.00398	0.00100	0.07300	0.11304	0.07300	0.18694	-3.0%
37	DM-1	0.01170	0.47742	0.00551	0.00000	0.01171	0.00398	0.00100	0.07314	0.45827	0.07314	0.50141	-0.9%
38	CL-1	0.01170	0.20890	0.00551	0.00000	0.01171	0.00398	0.00100	0.07314	0.18739	0.07314	0.45093	-1.3%
39	Group Total												
40	Group Total	0.01170	0.77746	0.00551	0.00000	0.01171	0.00398	0.00100	0.07312	0.76812	0.07312	0.76189	-4.4%
41	Total 1: Cust Gps.	0.01877	0.13735	0.00444	0.00000	0.00884	0.00317	0.00100	0.09398	0.17671	0.09398	0.27038	-3.6%

Table XI-57
Updated SCE's 2027 ERRRA Forecast Class Average Rates (Unbundled) Including GHG Climate Credit

Updated SCE's 2027 ERRRA Forecast Class Average Rates (Unbundled)													
Line No	Rate Schedule By Customer Group	Transmission (\$/kW-hr)	Distribution w/ GHG (\$/kW-hr)	NSGC (CA.M) (\$/kW-hr)	NOC (\$/kW-hr)	PPPC (\$/kW-hr)	DWR W/ LIFETIME (\$/kW-hr)	PERCF (\$/kW-hr)	PCA (CER) (\$/kW-hr)	Total Delivery (\$/kW-hr)	Total CER (\$/kW-hr)	Total w/ PC/CF (\$/kW-hr)	Percent Change Over Oct 2026 %
1	Dominant												
2	D	0.02481	0.21829	0.00723	0.00003	0.01121	0.00391	0.00100	0.04787	0.28430	0.04787	0.18117	6.2%
3	D-CARE	0.02481	0.05978	0.00723	0.00003	0.01278	-	0.00100	0.04787	0.10580	0.04787	0.13327	18.7%
4	DE	0.02481	0.12868	0.00723	0.00003	0.00842	0.00391	0.00100	0.04787	0.17780	0.04787	0.22527	6.7%
5	DM	0.02481	0.09399	0.00723	0.00003	0.01127	0.00391	0.00100	0.04787	0.14386	0.04787	0.19103	-6.3%
6	DM-1	0.02481	0.25416	0.00723	0.00003	0.01857	0.00391	0.00100	0.04787	0.30641	0.04787	0.35428	3.1%
7	DM-1-1	0.02481	0.25416	0.00723	0.00003	0.01857	0.00391	0.00100	0.04787	0.30641	0.04787	0.35428	3.1%
8	DM-1-2	0.02481	0.22051	0.00723	0.00003	0.01604	0.00391	0.00100	0.04787	0.27566	0.04787	0.32353	4.3%
9	Group Total												
10		0.02481	0.17711	0.00723	0.00003	0.01166	0.00440	0.00100	0.04787	0.22638	0.04787	0.27425	7.3%
11													
12	Lighting Small Med Power												
13	GS-1	0.01777	0.17758	0.00508	0.00003	0.00896	0.00391	0.00100	0.03165	0.17833	0.03165	0.20998	7.3%
14	GS-2	0.01483	0.17940	0.00494	0.00003	0.00808	0.00391	0.00100	0.02940	0.17228	0.02940	0.20468	7.4%
15	TC-1	0.01259	0.21867	0.00551	0.00003	0.01016	0.00391	0.00100	0.03318	0.24949	0.03318	0.28267	6.9%
16	TOC-GS	0.01378	0.11599	0.00644	0.00003	0.00783	0.00391	0.00100	0.02145	0.14918	0.02145	0.17063	6.1%
17													
18	Group Total	0.01385	0.13184	0.00687	0.00003	0.00867	0.00391	0.00100	0.02777	0.16737	0.02777	0.19514	7.1%
19													
20	Large Power												
21	TOC-S-S	0.01378	0.10269	0.00428	0.00003	0.00723	0.00391	0.00100	0.02340	0.13482	0.02340	0.15841	7.3%
22	TOC-S-P	0.01110	0.08688	0.00417	0.00003	0.00640	0.00391	0.00100	0.01877	0.11589	0.01877	0.13466	7.2%
23	TOC-S-T	0.00724	0.02815	0.00472	0.00003	0.00417	0.00391	0.00100	0.01941	0.06602	0.01941	0.08543	8.9%
24	TOC-S-S-S	0.01126	0.10012	0.00171	0.00003	0.00712	0.00391	0.00100	0.01887	0.12735	0.01887	0.14542	8.1%
25	TOC-S-S-P	0.00475	0.08355	0.00108	0.00003	0.00640	0.00391	0.00100	0.02519	0.10272	0.02519	0.12711	8.1%
26	TOC-S-S-T	0.00774	0.02912	0.00090	0.00003	0.00424	0.00391	0.00100	0.01884	0.04805	0.01884	0.06776	7.9%
27													
28	Group Total	0.01069	0.07470	0.00415	0.00003	0.00618	0.00391	0.00100	0.01839	0.10283	0.01839	0.12122	7.3%
29													
30	Agricultural & Pumping												
31	TOC-PA-2	0.01213	0.11798	0.00421	0.00003	0.00799	0.00391	0.00100	0.03416	0.14624	0.03416	0.18340	10.3%
32	TOC-PA-3	0.01069	0.09792	0.00359	0.00003	0.00641	0.00391	0.00100	0.02864	0.12382	0.02864	0.15446	9.9%
33													
34	Group Total	0.01156	0.10815	0.00391	0.00003	0.00722	0.00391	0.00100	0.03116	0.13777	0.03116	0.16832	10.1%
35													
36	Smart & Area Lighting												
37	LS-1	0.01170	0.59330	0.00311	0.00003	0.01171	0.00391	0.00100	0.03839	0.62018	0.03839	0.66805	3.2%
38	LS-2	0.01170	0.23885	0.00311	0.00003	0.01171	0.00391	0.00100	0.03839	0.36471	0.03839	0.40340	7.4%
39	LS-3	0.01170	0.06911	0.00311	0.00003	0.01171	0.00391	0.00100	0.03839	0.10297	0.03839	0.14186	17.2%
40	DW-L	0.01170	0.95032	0.00311	0.00003	0.01171	0.00391	0.00100	0.03839	0.88418	0.03839	1.02307	2.1%
41	OC-1	0.01170	0.34652	0.00311	0.00003	0.01171	0.00391	0.00100	0.03839	0.37438	0.03839	0.41227	3.3%
42													
43	Group Total	0.01170	0.29704	0.00311	0.00003	0.01171	0.00391	0.00100	0.03839	0.33080	0.03839	0.36979	6.0%
44													
45	Total 5 Cust Opn	0.01617	0.12480	0.00524	0.00003	0.00661	0.00250	0.00100	0.03005	0.16136	0.03005	0.19140	7.3%

Table XI-58
Updated Average Generation Rates

	Rate Schedule By Customer Group	10/1/2026 Generation (¢ / kWh)	2027 ERRRA Application Generation (¢ / kWh)	Percent Change Over Oct 2026 %
Domestic				
	Non-CARE	11.21	10.36	-7.60%
	D-CARE	11.22	10.36	-7.60%
	Group Total	11.21	10.36	-7.60%
Lighting-SM Med Power				
	GS-1	10.87	10.07	-7.41%
	GS-2	10.86	10.06	-7.36%
	TC-1	10.10	9.35	-7.39%
	TOU-GS-3	9.19	8.51	-7.33%
	Group Total	10.43	9.66	-7.36%
Large Power				
	TOU-8-SEC	9.30	8.61	-7.42%
	TOU-8-PRI	8.86	8.21	-7.37%
	TOU-8-SUB	7.86	7.28	-7.43%
	TOU-8-SEC-S	9.37	8.69	-7.29%
	TOU-8-PRI-S	8.71	8.07	-7.37%
	TOU-8-SUB-S	7.81	7.23	-7.40%
	Group Total	8.55	7.92	-7.43%
Agricultural & Pumping				
	TOU-PA-2	10.14	9.39	-7.37%
	TOU-PA-3	7.90	7.31	-7.40%
	Group Total	8.95	8.29	-7.37%
Street & Area Lighting				
	LS-1	5.74	5.31	-7.39%
	LS-2	5.73	5.31	-7.40%
	LS-3	5.82	5.39	-7.40%
	DWL	5.74	5.31	-7.39%
	OL-1	5.74	5.31	-7.39%
	Group Total	5.76	5.34	-7.40%
Grand Total		10.15	9.40	-7.36%

Appendix A

Estimated December 31, 2026 Balancing Account Balances

TABLE 1

2026

Energy Resource Recovery Account Balancing Account (ERRA BA)
(Thousands of Dollars)

Line No.	Description	Recorded January	Recorded February	Recorded March	Recorded April	Recorded May	Recorded June	Recorded July	Recorded August	Recorded September	Forecast October	Forecast November	Forecast December	Annual Summary
1.	Beginning Balance	(829,169)	(38,958)	(26,012)	54,943	(126,666)	(179,742)	(304,143)	(378,751)	(589,493)	(1,275,147)	(1,297,169)	(1,296,496)	(829,169)
2.	Transfers/Adjustments/Interest	829,169	-	-	-	-	-	-	-	-	-	-	-	829,169
3.	Adjusted Beginning Balance	-	(38,958)	(26,012)	54,943	(126,666)	(179,742)	(304,143)	(378,751)	(589,493)	(1,275,147)	(1,297,169)	(1,296,496)	-
4.	Customer Revenue	(388,712)	(276,073)	(261,611)	(451,017)	(350,569)	(478,584)	(626,134)	(837,769)	(552,705)	(440,566)	(311,547)	(374,663)	(5,349,949)
5.	Expenses	164,930	117,615	119,383	55,838	56,444	78,998	250,801	353,961	253,833	234,694	167,219	211,804	2,065,521
6.	Fuel & Purchased Power													
7.	Actual Retained RA													
8.	Actual Retained RPS													
9.	Subtotal Expenses	349,813	289,117	342,522	269,519	297,965	354,924	552,574	628,529	(130,056)	422,536	316,244	373,431	4,067,118
10.	Monthly (Over)/Under Collection	(38,899)	13,044	80,912	(181,498)	(52,604)	(123,660)	(73,560)	(209,240)	(682,761)	(18,030)	4,697	(1,231)	(1,282,831)
11.	Interest	(59)	(98)	44	(111)	(472)	(741)	(1,048)	(1,502)	(2,893)	(3,992)	(4,025)	(4,032)	(18,929)
12.	RUBA Transfer	-	-	-	-	-	-	-	-	-	-	-	28,580	28,580
13.	MSARFMA Transfer	-	-	-	-	-	-	-	-	-	-	-	-	-
14.	Total ERRA Ending Balance	(38,958)	(26,012)	54,943	(126,666)	(179,742)	(304,143)	(378,751)	(589,493)	(1,275,147)	(1,297,169)	(1,296,496)	(1,273,180)	(1,273,180)
15.	Interest Rate	3.65%	3.62%	3.62%	3.71%	3.70%	3.68%	3.69%	3.73%	3.73%	3.73%	3.73%	3.73%	

Estimated ERRA Ending Balance (1,273,180)
Removal of ERRA Trigger Revenue Requirement -
Adjusted Estimated ERRA BA Ending Balance (1,273,180)
FF&U (15,808)
Total ERRA w/ FF&U (1,288,988)

2026

TABLE 2

Portfolio Allocation Balancing Account (PABA)
(Thousands of Dollars)

Line No.	Description	Recorded January	Recorded February	Recorded March	Recorded April	Recorded May	Recorded June	Recorded July	Recorded August	Forecast September	Forecast October	Forecast November	Forecast December	Annual Summary
1.	Beginning Balance	1,420,831	543,719	508,312	502,256	581,343	622,800	721,795	729,922	729,620	1,458,907	1,432,108	1,468,510	1,420,831
2.	Transfers/Adjustments/Interest	(827,771)	(60)	-	(9)	-	-	(47,357)	(1,525)	(108,854)	-	-	-	(985,575)
3.	Adjusted Beginning Balance	593,060	543,659	508,312	502,247	581,343	622,800	674,439	728,396	620,765	1,458,907	1,432,108	1,468,510	435,256
4.	Customer Revenue	(41,791)	(28,363)	(27,328)	3,960	(11,153)	(13,387)	(8,833)	(13,152)	(14,320)	(13,161)	(15,188)	(15,037)	(197,753)
5.	Authorized Revenue	55,374	48,111	59,912	53,558	56,281	79,883	106,208	131,626	115,286	96,223	54,466	50,835	907,762
6.	Utility Owned Generation													
7.	Contracts													
8.	Resource Revenues													
9.	CAISO Market Revenues													
10.	Bilateral Transactions													
11.	Actual Retained RA													
12.	Actual Retained RPS													
13.	RA Sales													
14.	RPS Sales													
15.	Common and Indirect Costs													
16.	Total Expenses	(67,503)	(59,524)	(42,998)	17,082	(8,339)	27,633	(46,824)	(122,282)	731,188	(117,156)	(10,186)	(66,891)	234,198
17.	Total Over/Under Collection	(53,921)	(39,776)	(10,414)	74,599	36,788	94,129	50,551	(3,808)	832,154	(34,094)	29,091	(31,094)	944,208
18.	Interest	1,722	1,580	1,518	1,668	1,849	2,054	2,152	2,258	3,223	4,482	4,497	4,516	31,519
19.	Monthly Transfers	2,858	2,848	2,840	2,828	2,820	2,812	2,780	2,773	2,764	2,814	2,814	18,745	49,695
20.	Ending Balance	543,719	508,312	502,256	581,343	622,800	721,795	729,922	729,620	1,458,907	1,432,108	1,468,510	1,460,677	1,460,677
21.	Interest Rates	3.65%	3.62%	3.62%	3.71%	3.70%	3.68%	3.69%	3.73%	3.73%	3.73%	3.73%	3.73%	

System Reliability Historical Costs Amortization (1/3 Removal)		Estimated PABA Ending Balance	1,460,677
Adjusted Estimated PABA Ending Balancing		GRCRRMA Removal	(39,576)
FF&U		1,421,100	
Total PABA w/ FF&U		17,645	
Less:			
		PCBA	(939)
		MPBA	7,428
		PBOPBA	(1,902)
		TAMA	(157,924)
Total PABA w/ FF&U Adjusted for Presentation			1,592,083

TABLE 3a

Energy Settlement Memorandum Account (ESMA)/Litigation Cost Tracking Account (LCTA)
(Thousands of Dollars)

ENERGY SETTLEMENT MEMORANDUM ACCOUNT														
Line No.	Description	Recorded January	Recorded February	Recorded March	Recorded April	Recorded May	Recorded June	Recorded July	Recorded August	Recorded September	Forecast October	Forecast November	Forecast December	Annual Summary
1.	Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
2.	Transfer to PABA	-	-	-	-	-	-	-	-	-	-	-	-	-
3.	Adjusted Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
4.	Monthly (Over)/Under Collection	-	-	-	-	-	-	-	-	-	-	-	-	-
5.	Total Refund Received	-	-	-	-	-	-	-	-	-	-	-	-	-
6.	Litigation Reimbursement Received	-	-	-	-	-	-	-	-	-	-	-	-	-
7.	Other Market Participant Amounts Paid	-	-	-	-	-	-	-	-	-	-	-	-	-
8.	Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-
9.	Settlement Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-
10.	Total Amount to be Refunded to Customers	-	-	-	-	-	-	-	-	-	-	-	-	-
11.	Interest	-	-	-	-	-	-	-	-	-	-	-	-	-
12.	Ending Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
13.	Interest Rates	3.65%	3.62%	3.62%	3.71%	3.70%	3.68%	3.69%	3.73%	3.73%	3.73%	3.73%	3.73%	
Estimated ESMA Ending Balance														
FF&U														-
Total ESMA w/ FF&U														-

TABLE 3b

LITIGATION COST TRACKING ACCOUNT

Line No.	Description	Recorded January	Recorded February	Recorded March	Recorded April	Recorded May	Recorded June	Recorded July	Recorded August	Recorded September	Forecast October	Forecast November	Forecast December	Annual Summary
14.	Beginning Balance	1,562	(0)	40	67	134	135	135	136	136	141	141	141	1,562
15.	Transfer to PABA	(1,562)	0	-	-	-	-	-	-	-	-	-	-	(1,562)
16.	Adjusted Beginning Balance	-	0	40	67	134	135	135	136	136	141	141	141	0
17.	Incurred Litigation Expense:													
18.	Law	-	40	26	67	-	-	0	-	4	-	-	-	138
19.	Subtotal	-	40	26	67	-	-	0	-	4	-	-	-	138
20.	Monthly (Over)/Under Collection	-	40	26	67	-	-	0	-	4	-	-	-	138
21.	Interest:	-	0	0	0	0	0	0	0	0	0	0	0	4
22.	Ending Balance	-	40	67	134	135	135	136	136	141	141	141	142	142
23.	Interest Rates	3.65%	3.62%	3.62%	3.71%	3.70%	3.68%	3.69%	3.73%	3.73%	3.73%	3.73%	3.73%	
Estimated LCTA Ending Balance142 Removal of Costs Pending in 2021 ERRR Review- Adjusted Estimated LCTA Ending Balance142 FF&U2 Total LCTA w/ FF&U144														

2026

TABLE 5

Tree Mortality Non-Bypassable Charge Balancing Account (TMNBCBA)
(Thousands of Dollars)

Line No.	Description	Recorded January	Recorded February	Recorded March	Recorded April	Recorded May	Recorded June	Recorded July	Recorded August	Recorded September	Forecast October	Forecast November	Forecast December	Annual Summary
1.	Beginning Balance	16,690	13,072	12,543	13,320	11,904	9,919	7,321	6,166	4,537	4,272	3,561	3,349	16,690
2.	Transfers/Adjustments/Interest	-	-	-	-	-	-	-	-	-	-	-	-	-
3.	Adjusted Beginning Balance	16,690	13,072	12,543	13,320	11,904	9,919	7,321	6,166	4,537	4,272	3,561	3,349	16,690
4.	Customer Revenue	(5,141)	(2,488)	(2,580)	(3,153)	(3,076)	(4,239)	(2,536)	(3,551)	(3,033)	(2,008)	(2,065)	(2,090)	(35,960)
5.	Market Revenue													
6.	Power Procurement Expenses													
7.	Monthly Under/(Over) Collection	(3,663)	(568)	738	(1,454)	(2,019)	(2,624)	(1,176)	(1,646)	(278)	(723)	(223)	(783)	(14,419)
8.	Interest	45	39	39	39	34	26	21	17	14	12	11	9	305
9.	Ending Balance	13,072	12,543	13,320	11,904	9,919	7,321	6,166	4,537	4,272	3,561	3,349	2,575	2,575
10.	Interest Rates	3.65%	3.62%	3.62%	3.71%	3.70%	3.68%	3.69%	3.73%	3.73%	3.73%	3.73%	3.73%	
Estimated TMNBCBA Ending Balance														2,575
FF&U														32
Total TMNBCBA w/ FF&U														2,607

2026

TABLE 6

BioMAT Non-Bypassable Charge Balancing Account (BMNBCBA)

(Thousands of Dollars)

Line No.	Description	Recorded January	Recorded February	Recorded March	Recorded April	Recorded May	Recorded June	Recorded July	Recorded August	Recorded September	Forecast October	Forecast November	Forecast December	Annual Summary
1.	Beginning Balance	(4,909)	(4,705)	(4,681)	(4,477)	(4,323)	(4,467)	(4,337)	(4,301)	(4,207)	(3,763)	(3,419)	(3,134)	(4,909)
2.	Transfers/Adjustments/Interest	-	-	-	-	-	-	-	-	-	-	-	-	-
	Adjusted Beginning Balance	(4,909)	(4,705)	(4,681)	(4,477)	(4,323)	(4,467)	(4,337)	(4,301)	(4,207)	(3,763)	(3,419)	(3,134)	(4,909)
3.	Customer Revenue	232	5	6	7	6	6	4	6	5	5	4	5	291
4.	BioMAT Contracts / O&M Expense													
5.	Market Revenues													
6.	Current Under/(Over) Collection	219	38	218	167	(130)	143	49	107	456	356	295	252	2,171
7.	Interest	(15)	(14)	(14)	(14)	(14)	(13)	(13)	(13)	(12)	(11)	(10)	(9)	(153)
8.	Ending Balance	(4,705)	(4,681)	(4,477)	(4,323)	(4,467)	(4,337)	(4,301)	(4,207)	(3,763)	(3,419)	(3,134)	(2,891)	(2,891)
9.	Interest Rates	3.65%	3.62%	3.62%	3.71%	3.70%	3.68%	3.69%	3.73%	3.73%	3.73%	3.73%	3.73%	
Estimated BMNBCBA Ending Balance (2,891)														
FF&U (36)														
Total BMNBCBA w/ FF&U (2,927)														

2026

TABLE 7

Modified Cost Allocation Mechanism Balancing Account (MCAM BA)
(Thousands of Dollars)

Line No.	Description	Recorded January	Recorded February	Recorded March	Recorded April	Recorded May	Recorded June	Recorded July	Recorded August	Recorded September	Forecast October	Forecast November	Forecast December	Annual Summary
1.	Beginning Balance	3,249	3,493	3,391	3,410	2,998	2,751	2,528	2,418	1,961	1,717	1,500	1,300	3,249
2.	Transfers/Adjustments/Interest	-	-	-	-	-	-	-	-	-	-	-	-	-
	Adjusted Beginning Balance	3,249	3,493	3,391	3,410	2,998	2,751	2,528	2,418	1,961	1,717	1,500	1,300	3,249
3.	Customer Revenue	(195)	(521)	(328)	(828)	(599)	(549)	(637)	(754)	(617)	(546)	(495)	(535)	(6,602)
4.	Opt-Out LSE Customers Sub-Account	430	408	336	406	343	318	519	289	367	324	291	186	4,218
6.	Current Under/(Over) Collection	234	(113)	9	(422)	(256)	(231)	(117)	(464)	(250)	(222)	(204)	(349)	(2,385)
7.	Interest	10	10	10	10	9	8	8	7	6	5	4	3	91
8.	Ending Balance	3,493	3,391	3,410	2,998	2,751	2,528	2,418	1,961	1,717	1,500	1,300	955	955
9.	Interest Rates	3.65%	3.62%	3.62%	3.71%	3.70%	3.68%	3.69%	3.73%	3.73%	3.73%	3.73%	3.73%	
Estimated MCAMBA Ending Balance 955 MCAM Historical Costs Amortization (1/3 Removal) - Adjusted MCAMBA Ending Balance 955 FF&U 12 Total MCAMBA w/ FF&U 967														

Appendix B

Indifference Rate Calculation

Areas shaded in gray are confidential per D 06-06-066, Matrix section V C

IOU Total Portfolio Summary

Pre-2002	Vintage portfolios										2027 ERRR Forecast Application (October)										Total	
	CTC Eligible	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026		New QIP SOC
Incremental by Year	442	779,236	650,323	183,648	226,936	48,794	36,322	80,195	59,040	7,969	1,542	1,566	17,837	-	621,846	-	380,782	-	57,397	147,794	-	3,454,941
	8,223	-	8,223	-	-	-	-	21	41	202	-	-	1,671	-	1,988	-	11,509	-	-	21	-	11,509
	1	-	-	23	142	34	21	41	65	23	-	-	-	-	1,865	-	354	-	359	1,399	-	4,335
	4	1,354	1,359	207	238	28	49	341	520	161	2	25	696	-	696	-	2,934	-	942	939	-	11,810
	0	27	27	23	23	23	23	23	23	23	25	324	-	-	-	-	261	-	261	261	-	11,810
	0	761	1,007	5	5	13	260	75	63	1	-	-	-	-	985	-	1,319	-	296	261	-	5,424
	7	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible	CRS Eligible

Indifference Calculation Inputs and Sources

2027 ERRR Forecast Application (October)

Line No.	Description	Source of Data	Value
1.	On Peak SP 15 Price (\$/MWh)	Energy Division	\$ 34.41
2.	Off Peak SP 15 Price (\$/MWh)	Energy Division	\$ 44.89
3.	On Peak Time Weight (%)	NERC 6x16 - On Peak Hours	55%
4.	Off Peak Time Weight (%)	NERC 6x16 - Off Peak Hours	45%
5.	Portfolio Weight (%)	as filed in SCE's Supplemental Testimony (8/15/23)	83%
6.	Energy Index (\$/MWh)	Line 1 x Line 3 + Line 2 x Line 4	\$ 32.54
7.	Forecast RPS Adder (\$/MWh)	Energy Division	\$ 12.69
8.	Forecast System RA Adder (\$/kW-Year)	Energy Division	\$ 120.24
9.	Forecast Local RA Adder (\$/kW-Year)	Energy Division	\$ 120.24
10.	Forecast Flexible RA Adder (\$/kW-Year)	Energy Division	\$ 120.24
11.	Uncollectibles Factor ¹	GRC (2025 GRC - D.25-09-030) and Advice 5663-E	0.997030

¹ This factor is specific to each utility. This factor now reflects only the uncollectibles factor and has removed the franchise fees.

Indifference Amount Calculation

2027 ERA Forecast Application (October)

Line No.	Description	Equation	Unit	CTC-Eligible	One-Time Reliance-Costs Applicable to All Customers	Legacy UOG	2004-2009	2010 ¹	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	New OF SOC	Sum												
Cost of Portfolio																																						
1.	CRS Eligible Portfolio Costs	Portfolio Summary Line 1	5000	442		\$	779,226	\$	660,323	\$	183,648	\$	660,323	\$	48,794	\$	34,252	\$	80,106	\$	59,600	\$	7,860	\$	1,542	\$	1,866	\$	171,837	\$	1,866	\$	621,646	-	\$	3,456,841		
2.	CRS Eligible Non-Renewable Supply at Generator Margin	Portfolio Summary Line 2	GWh	-		\$	8,423	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	\$	11,509		
3.	CRS Eligible Renewable Supply at Generator Margin	Portfolio Summary Line 3	GWh	7		\$	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	\$	4,336	
4.	CRS Eligible Local NDC	Portfolio Summary Line 4	5000	20		\$	500	\$	330	\$	100	\$	330	\$	5	\$	3	\$	21	\$	441	\$	66	\$	23	\$	1,866	\$	1,866	\$	1,866	\$	1,866	\$	3,900	\$	1,399	
5.	CRS Eligible Local NDC	Portfolio Summary Line 5	MW	0		\$	761	\$	1,007	\$	27	\$	260	\$	75	\$	13	\$	260	\$	75	\$	62	\$	1	\$	25	\$	334	\$	334	\$	334	\$	206	\$	2,801	
6.	CRS Eligible Local NDC	Portfolio Summary Line 6	MW	0		\$	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	\$	4,434
7.	CRS Eligible Local NDC	Portfolio Summary Line 7	MW	0		\$	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	\$	4,434
Market Value of Portfolio																																						
8.	Market Value of Energy	Line 2	GWh	-		\$	8,423	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	\$	11,509	
9.	Market Value of RPS	Line 3	GWh	7		\$	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	\$	4,336	
10.	Market Value of RPS	Line 4	5000	91		\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	
11.	Market Value of RPS	Line 5	5000	233		\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	
12.	Market Value of Energy	Sum (Line 8, 10) + Line 11	\$/MWh	0		\$	274,007	\$	274,007	\$	274,007	\$	274,007	\$	274,007	\$	274,007	\$	274,007	\$	274,007	\$	274,007	\$	274,007	\$	274,007	\$	274,007	\$	274,007	\$	274,007	\$	274,007	\$	274,007	
13.	Market Value of RPS	Line 13	GWh	7		\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	
14.	Market Value of RPS	Line 14	5000	91		\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	\$	12,609	
15.	Market Value of RPS	Line 15	5000	233		\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	\$	32,547	
16.	Market Value of Capacity	Line 16	MW	0		\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	
17.	Market Value of Capacity	Line 17	MW	0		\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	
18.	Market Value of Capacity	Line 18	MW	0		\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	
19.	Market Value of Capacity	Line 19	MW	0		\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	
20.	Market Value of Capacity	Line 20	MW	0		\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	
21.	Market Value of Capacity	Line 21	MW	0		\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	
22.	Market Value of Capacity	Line 22	MW	0		\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	
23.	Market Value of Capacity	Line 23	MW	0		\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	
24.	Market Value of Capacity	Line 24	MW	0		\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769	\$	192,769							

¹ The Portfolio \$/MWh was based N/A for 2010 and 2016 as CRS Eligible Renewable Supply at Generator Margin was so small that the resulting calculation would result in a \$/MWh cost in the million.

Power Charge Indifference Adjustment (PCIA) Revenue Requirement

Line No.	Description	Guidance	Unit	CTC-Eligible	One-Time Refund Costs Applicable to All Customers ²	Legacy UOG	2004-2009																	New Q1 SOC	Total																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																												
							2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																														
31.	Adjusted Indifference Amount (Market)	Line 31 from Ind Amt Calc	\$000																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																																		</

Notes:

¹ This factor now reflects only the Uncharacteristic factor of 0.99703 in SCE's Advice 5663-E.

² Examples of entries to this sub-account are DWR Refunds and Energy Credit-related refund costs, among other items.

Diffidence Rate Calculation

2027 ERRR Forecast Application (October)

		FARA Revenue Requirement Allocation to Rate Groups – Vintage Revenue Requirement & PCA Affecter by Vintage																							
CTC	One-Time Refunds / Cuts	New OF SOC	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026				
\$	1,851	\$ 94	\$ 983	\$ 616,664	\$ 853,232	\$ 270,852	\$ 349,611	\$ 72,991	\$ 66,068	\$ 292,187	\$ 254,512	\$ 19,710	\$ 1,003	\$ 15,305	\$ 20,289	\$ 11,432	\$ 201,177	\$ (15,775)	\$ (29,515)	\$ 12,334	\$ (6,167)	\$ (1,316,768)			
\$	786	\$ 40	\$ 418	\$ 278,330	\$ 385,105	\$ 123,352	\$ 162,257	\$ 33,967	\$ 30,905	\$ 137,231	\$ 139,373	\$ 9,247	\$ 472	\$ 7,358	\$ 9,319	\$ 5,323	\$ 93,747	\$ (7,573)	\$ (13,890)	\$ 5,811	\$ (2,906)	\$ (618,088)			
\$	120	\$ 6	\$ 64	\$ 42,346	\$ 58,391	\$ 18,748	\$ 24,298	\$ 5,086	\$ 4,624	\$ 20,528	\$ 17,887	\$ 1,386	\$ 71	\$ 1,039	\$ 1,358	\$ 761	\$ 13,407	\$ (1,012)	\$ (1,935)	\$ 808	\$ (404)	\$ (55,864)			
\$	1	\$ 0	\$ 1	\$ 388	\$ 12	\$ 226	\$ 47	\$ 43	\$ 191	\$ 166	\$ 11	\$ 1	\$ 1	\$ 0	\$ 14	\$ 8	\$ 118	\$ (11)	\$ (20)	\$ 8	\$ (6)	\$ (980)			
\$	270	\$ 14	\$ 144	\$ 90,882	\$ 125,746	\$ 39,745	\$ 50,930	\$ 10,656	\$ 9,655	\$ 42,642	\$ 37,153	\$ 2,877	\$ 147	\$ 2,183	\$ 2,853	\$ 1,583	\$ 27,763	\$ (2,061)	\$ (3,911)	\$ 1,631	\$ (816)	\$ (173,397)			
\$	152	\$ 8	\$ 81	\$ 45,839	\$ 63,411	\$ 19,913	\$ 25,121	\$ 5,220	\$ 4,720	\$ 20,748	\$ 18,114	\$ 1,401	\$ 72	\$ 1,066	\$ 1,438	\$ 806	\$ 14,205	\$ (1,049)	\$ (2,024)	\$ 845	\$ (423)	\$ (89,879)			
\$	152	\$ 8	\$ 81	\$ 45,812	\$ 66,381	\$ 20,956	\$ 25,620	\$ 5,233	\$ 4,816	\$ 21,260	\$ 18,519	\$ 1,434	\$ 71	\$ 1,057	\$ 1,462	\$ 806	\$ 14,006	\$ (1,022)	\$ (1,954)	\$ 865	\$ (407)	\$ (85,986)			
\$	113	\$ 6	\$ 60	\$ 32,381	\$ 44,083	\$ 13,733	\$ 16,850	\$ 3,462	\$ 3,046	\$ 13,449	\$ 11,717	\$ 908	\$ 46	\$ 663	\$ 948	\$ 510	\$ 8,980	\$ (685)	\$ (1,279)	\$ 532	\$ (263)	\$ (55,855)			
\$	110	\$ 5	\$ 59	\$ 29,277	\$ 40,647	\$ 12,540	\$ 16,040	\$ 3,303	\$ 2,983	\$ 12,509	\$ 10,899	\$ 840	\$ 43	\$ 677	\$ 974	\$ 474	\$ 8,114	\$ (623)	\$ (1,188)	\$ 466	\$ (232)	\$ (49,755)			
\$	36	\$ 2	\$ 19	\$ 12,799	\$ 17,709	\$ 5,670	\$ 7,434	\$ 1,556	\$ 1,409	\$ 6,249	\$ 5,481	\$ 423	\$ 22	\$ 327	\$ 473	\$ 272	\$ 4,408	\$ (385)	\$ (744)	\$ 312	\$ (156)	\$ (33,225)			
\$	37	\$ 2	\$ 20	\$ 12,987	\$ 17,859	\$ 5,720	\$ 7,586	\$ 1,571	\$ 1,428	\$ 6,340	\$ 5,548	\$ 439	\$ 22	\$ 325	\$ 469	\$ 283	\$ 4,624	\$ (386)	\$ (782)	\$ 322	\$ (164)	\$ (35,845)			
\$	10	\$ 0	\$ 5	\$ 3,995	\$ 4,974	\$ 1,589	\$ 2,087	\$ 437	\$ 398	\$ 1,765	\$ 1,525	\$ 118	\$ 6	\$ 91	\$ 133	\$ 76	\$ 1,242	\$ (102)	\$ (196)	\$ 78	\$ (38)	\$ (5,288)			
\$	1	\$ 0	\$ 2	\$ 944	\$ 1,307	\$ 419	\$ 551	\$ 115	\$ 105	\$ 466	\$ 409	\$ 3	\$ 2	\$ 32	\$ 58	\$ 20	\$ 363	\$ (30)	\$ (58)	\$ 24	\$ (12)	\$ (2,582)			
\$	12	\$ 1	\$ 6	\$ 3,660	\$ 5,341	\$ 1,711	\$ 2,241	\$ 469	\$ 427	\$ 1,895	\$ 1,667	\$ 129	\$ 7	\$ 97	\$ 143	\$ 79	\$ 1,277	\$ (113)	\$ (219)	\$ 92	\$ (46)	\$ (9,873)			
\$	46	\$ 2	\$ 25	\$ 14,905	\$ 20,623	\$ 6,606	\$ 8,451	\$ 1,769	\$ 1,610	\$ 6,834	\$ 6,053	\$ 469	\$ 24	\$ 380	\$ 586	\$ 331	\$ 5,584	\$ (483)	\$ (935)	\$ 394	\$ (197)	\$ (42,166)			

Forecast Sales of Those Responsible for Each Portfolio of Resources (CvH)

CTC	One-Time Refunds / Cuts	New OF SOC	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
27,535	27,496	27,496	27,478	27,478	27,478	27,478	27,478	27,478	27,478	27,178	27,178	27,178	27,038	26,709	21,922	21,700	21,487	21,106	19,931	19,824	19,824	19,824	19,687	19,687	19,687
5,769	5,767	5,767	5,729	5,729	5,729	5,638	5,634	5,632	5,581	5,581	5,559	5,486	5,169	4,737	4,234	4,211	3,865	3,808	3,777	3,777	3,777	3,788	3,788	3,788	3,788
52	51	51	50	50	50	50	50	50	50	50	49	47	42	42	42	42	39	38	38	38	38	38	38	38	38
12,919	12,911	12,911	12,257	12,257	12,257	11,787	11,776	11,727	11,663	11,555	11,486	10,827	9,168	8,616	8,093	7,848	7,848	7,672	7,601	7,599	7,545	7,545	7,545	7,545	7,545
7,330	7,330	7,330	6,230	6,188	6,188	5,858	5,814	5,779	5,678	5,678	5,647	5,329	4,723	4,256	4,483	4,101	4,083	3,969	3,968	3,968	3,968	3,942	3,942	3,942	3,942
7,432	7,414	7,414	6,644	6,644	6,644	6,222	6,034	5,998	5,953	5,896	5,708	5,364	4,809	4,596	4,490	3,984	3,883	3,841	3,840	3,831	3,831	3,831	3,831	3,831	3,831
5,861	5,747	5,747	4,678	4,678	4,678	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469	4,469
5,928	5,928	5,928	4,455	4,455	4,455	3,980	3,938	3,847	3,812	3,791	3,791	3,791	3,791	3,791	3,791	3,791	3,791	3,791	3,791	3,791	3,791	3,791	3,791	3,791	3,791
1,670	1,667	1,667	1,655	1,655	1,655	1,649	1,649	1,642	1,642	1,635	1,635	1,635	1,626	1,626	1,626	1,626	1,626	1,626	1,626	1,626	1,626	1,626	1,626	1,626	1,626
1,872	1,872	1,872	1,771	1,771	1,771	1,767	1,764	1,764	1,764	1,764	1,764	1,764	1,764	1,764	1,764	1,764	1,764	1,764	1,764	1,764	1,764	1,764	1,764	1,764	1,764
419	416	416	407	407	407	406	406	406	406	406	406	406	406	406	406	406	406	406	406	406	406	406	406	406	406
600	600	600	556	556	556	554	554	554	554	554	554	554	554	554	554	554	554	554	554	554	554	554	554	554	554
2,507	2,507	2,507	2,265	2,265	2,265	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263	2,263
79,944	79,885	79,885	74,302	74,302	74,302	73,523	73,523	73,523	73,523	73,523	73,523	73,523	73,523	73,523	73,523	73,523	73,523	73,523	73,523	73,523	73,523	73,523	73,523	73,523	73,523

Incremental Rate for Each Portfolio of Resources (Vintage Indifference Amount by Rate Group / Forecast Sales by Rate Group)

CTC	One-Time Refunds/Cuts	New OF SOC	Legacy UOG	2004-2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
\$0.0001	\$0.0000	\$0.0002	\$0.0101	\$0.0102	\$0.0040	\$0.0091	\$0.0014	\$0.0012	\$0.0050	\$0.0049	\$0.0034	\$0.0002	\$0.0028	\$0.0043	\$0.0025	\$0.0046	(\$0.0016)	(\$0.0070)	\$0.0029	(\$0.0015)	(\$0.0140)
\$0.0002	\$0.0000	\$0.0000	\$0.0079	\$0.0083	\$0.0028	\$0.0041	\$0.0039	\$0.0002	\$0.00365	\$0.0031	\$0.0025	\$0.0001	\$0.0020	\$0.0001	\$0.0001	\$0.0018	(\$0.0026)	(\$0.0051)	\$0.0021	(\$0.0011)	(\$0.0279)
\$0.0002	\$0.0000	\$0.0000	\$0.0079	\$0.0084	\$0.0009	\$0.0004	\$0.0004	\$0.0000	\$0.0030	\$0.0034	\$0.0039	\$0.0001	\$0.0002	\$0.0001	\$0.0001	\$0.0012	(\$0.0027)	(\$0.0051)	\$0.0021	(\$0.0011)	(\$0.0279)
\$0.0002	\$0.0000	\$0.0001	\$0.0074	\$0.0029	\$0.0042	\$0.0039	\$0.0002	\$0.00366	\$0.0032	\$0.0025	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0017	(\$0.0026)	(\$0.0051)	\$0.0021	(\$0.0011)	(\$0.0279)
\$0.0002	\$0.0000	\$0.0001	\$0.0074	\$0.0018	\$0.0026	\$0.0029	\$0.0002	\$0.00363	\$0.0039	\$0.0035	\$0.0039	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0017	(\$0.0026)	(\$0.0051)	\$0.0021	(\$0.0011)	(\$0.0279)
\$0.0002	\$0.0000	\$0.0001	\$0.0074	\$0.0002	\$0.0023	\$0.0023	\$0.0002	\$0.00363	\$0.0039	\$0.0035	\$0.0039	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0017	(\$0.0026)	(\$0.0051)	\$0.0021	(\$0.0011)	(\$0.0279)
\$0.0002	\$0.0000	\$0.0001	\$0.00693	\$0.0059	\$0.0067	\$0.0044	\$0.0085	\$0.0077	\$0.00342	\$0.0031	\$0.0023	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00593	\$0.0092	\$0.0092	\$0.0084	\$0.0092	\$0.0073	\$0.0025	\$0.0026	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.0073	\$0.0070	\$0.0041	\$0.0094	\$0.0086	\$0.0081	\$0.0031	\$0.0025	\$0.0026	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.0121	\$0.0091	\$0.0144	\$0.0108	\$0.0086	\$0.00435	\$0.00330	\$0.0022	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00729	\$0.0008	\$0.0023	\$0.0045	\$0.0089	\$0.0081	\$0.00359	\$0.00316	\$0.0024	\$0.0001	\$0.0001	\$0.0001	\$0.0001	\$0.0029	(\$0.0025)	(\$0.0048)	\$0.0020	(\$0.0010)	(\$0.0249)
\$0.0002	\$0.0000	\$0.0001	\$0.00852	\$0.012																	

PARA Rates (Cumulative) - Base PCIA -DWREC																					
Rate Group	PCIA 2001 Vintage	PCIA 2004 Vintage	PCIA 2009 Vintage	PCIA 2010 Vintage	PCIA 2011 Vintage	PCIA 2012 Vintage	PCIA 2013 Vintage	PCIA 2014 Vintage	PCIA 2015 Vintage	PCIA 2016 Vintage	PCIA 2017 Vintage	PCIA 2018 Vintage	PCIA 2019 Vintage	PCIA 2020 Vintage	PCIA 2021 Vintage	PCIA 2022 Vintage	PCIA 2023 Vintage	PCIA 2024 Vintage	PCIA 2025 Vintage	PCIA 2026 Vintage	PCIA 2027 Vintage
Domestic	\$ 0.00002	\$ 0.00002	\$ 0.02416	\$ 0.02865	\$ 0.03456	\$ 0.03579	\$ 0.03692	\$ 0.04191	\$ 0.04630	\$ 0.04664	\$ 0.04666	\$ 0.04694	\$ 0.04736	\$ 0.04761	\$ 0.05197	\$ 0.05161	\$ 0.05902	\$ 0.05121	\$ 0.05106	\$ 0.01967	\$ 0.01967
TOUG-GS-1	\$ 0.00001	\$ 0.00001	\$ 0.01763	\$ 0.02091	\$ 0.02522	\$ 0.02612	\$ 0.02694	\$ 0.03058	\$ 0.03379	\$ 0.03404	\$ 0.03405	\$ 0.03425	\$ 0.03456	\$ 0.03474	\$ 0.03792	\$ 0.03766	\$ 0.03715	\$ 0.03737	\$ 0.03726	\$ 0.01435	\$ 0.01435
TC-1	\$ 0.00001	\$ 0.00001	\$ 0.01837	\$ 0.02179	\$ 0.02628	\$ 0.02722	\$ 0.02808	\$ 0.03187	\$ 0.03521	\$ 0.03547	\$ 0.03549	\$ 0.03570	\$ 0.03602	\$ 0.03621	\$ 0.03952	\$ 0.03925	\$ 0.03872	\$ 0.03894	\$ 0.03883	\$ 0.01496	\$ 0.01496
TOUG-GS-2	\$ 0.00001	\$ 0.00001	\$ 0.01769	\$ 0.02097	\$ 0.02529	\$ 0.02620	\$ 0.02702	\$ 0.03068	\$ 0.03389	\$ 0.03414	\$ 0.03416	\$ 0.03436	\$ 0.03467	\$ 0.03485	\$ 0.03804	\$ 0.03778	\$ 0.03727	\$ 0.03748	\$ 0.03738	\$ 0.01439	\$ 0.01439
TOUG-GS-3	\$ 0.00001	\$ 0.00001	\$ 0.01755	\$ 0.02081	\$ 0.02510	\$ 0.02599	\$ 0.02681	\$ 0.03044	\$ 0.03363	\$ 0.03388	\$ 0.03389	\$ 0.03409	\$ 0.03440	\$ 0.03458	\$ 0.03774	\$ 0.03748	\$ 0.03698	\$ 0.03719	\$ 0.03708	\$ 0.01428	\$ 0.01428
TOUG-Sec	\$ 0.00001	\$ 0.00001	\$ 0.01728	\$ 0.02049	\$ 0.02471	\$ 0.02559	\$ 0.02640	\$ 0.02997	\$ 0.03311	\$ 0.03335	\$ 0.03336	\$ 0.03356	\$ 0.03387	\$ 0.03404	\$ 0.03716	\$ 0.03690	\$ 0.03641	\$ 0.03662	\$ 0.03651	\$ 0.01406	\$ 0.01406
TOUG-S-Pri	\$ 0.00001	\$ 0.00001	\$ 0.01654	\$ 0.01961	\$ 0.02365	\$ 0.02450	\$ 0.02527	\$ 0.02869	\$ 0.03169	\$ 0.03193	\$ 0.03194	\$ 0.03213	\$ 0.03242	\$ 0.03259	\$ 0.03557	\$ 0.03533	\$ 0.03485	\$ 0.03505	\$ 0.03495	\$ 0.01346	\$ 0.01346
TOUG-S-Sub	\$ 0.00001	\$ 0.00001	\$ 0.01573	\$ 0.01865	\$ 0.02249	\$ 0.02330	\$ 0.02403	\$ 0.02728	\$ 0.03014	\$ 0.03036	\$ 0.03037	\$ 0.03055	\$ 0.03083	\$ 0.03099	\$ 0.03383	\$ 0.03360	\$ 0.03314	\$ 0.03333	\$ 0.03324	\$ 0.01280	\$ 0.01280
TOUG-PA-2	\$ 0.00001	\$ 0.00001	\$ 0.01844	\$ 0.02187	\$ 0.02638	\$ 0.02732	\$ 0.02818	\$ 0.03199	\$ 0.03534	\$ 0.03560	\$ 0.03562	\$ 0.03583	\$ 0.03615	\$ 0.03634	\$ 0.03967	\$ 0.03940	\$ 0.03886	\$ 0.03909	\$ 0.03898	\$ 0.01501	\$ 0.01501
TOUG-PA-3	\$ 0.00001	\$ 0.00001	\$ 0.01738	\$ 0.02061	\$ 0.02486	\$ 0.02575	\$ 0.02656	\$ 0.03016	\$ 0.03332	\$ 0.03356	\$ 0.03357	\$ 0.03377	\$ 0.03408	\$ 0.03425	\$ 0.03739	\$ 0.03714	\$ 0.03664	\$ 0.03685	\$ 0.03674	\$ 0.01415	\$ 0.01415
St. Lighting	\$ 0.00001	\$ 0.00001	\$ 0.02104	\$ 0.02495	\$ 0.03010	\$ 0.03117	\$ 0.03215	\$ 0.03650	\$ 0.04033	\$ 0.04062	\$ 0.04064	\$ 0.04088	\$ 0.04125	\$ 0.04146	\$ 0.04426	\$ 0.04495	\$ 0.04454	\$ 0.04460	\$ 0.04447	\$ 0.01713	\$ 0.01713
Standby - Sec	\$ 0.00001	\$ 0.00001	\$ 0.01685	\$ 0.01999	\$ 0.02411	\$ 0.02497	\$ 0.02575	\$ 0.02924	\$ 0.03230	\$ 0.03254	\$ 0.03255	\$ 0.03274	\$ 0.03304	\$ 0.03321	\$ 0.03625	\$ 0.03600	\$ 0.03552	\$ 0.03572	\$ 0.03562	\$ 0.01372	\$ 0.01372
Standby - Pri	\$ 0.00001	\$ 0.00001	\$ 0.01655	\$ 0.01963	\$ 0.02367	\$ 0.02452	\$ 0.02529	\$ 0.02871	\$ 0.03172	\$ 0.03196	\$ 0.03197	\$ 0.03216	\$ 0.03245	\$ 0.03262	\$ 0.03560	\$ 0.03536	\$ 0.03488	\$ 0.03508	\$ 0.03498	\$ 0.01347	\$ 0.01347
Standby - Sub	\$ 0.00001	\$ 0.00001	\$ 0.01569	\$ 0.01863	\$ 0.02245	\$ 0.02325	\$ 0.02398	\$ 0.02722	\$ 0.03008	\$ 0.03030	\$ 0.03031	\$ 0.03049	\$ 0.03076	\$ 0.03092	\$ 0.03376	\$ 0.03352	\$ 0.03307	\$ 0.03326	\$ 0.03317	\$ 0.01277	\$ 0.01277
System Average	\$ 0.00001	\$ 0.00001	\$ 0.01980	\$ 0.02354	\$ 0.02936	\$ 0.02936	\$ 0.03029	\$ 0.03441	\$ 0.03803	\$ 0.03831	\$ 0.03833	\$ 0.03855	\$ 0.03890	\$ 0.03910	\$ 0.04270	\$ 0.04240	\$ 0.04183	\$ 0.04207	\$ 0.04195	\$ 0.01608	\$ 0.01608

Surcharges and Refunds to be Added to PCIA Rates											
Rate Group	PCIA 2001 Vintage	PCIA 2004 Vintage	PCIA 2009 Vintage	PCIA 2010 Vintage	PCIA 2011 Vintage	PCIA 2012 Vintage	PCIA 2013 Vintage	PCIA 2014 Vintage	PCIA 2015 Vintage	PCIA 2016 Vintage	PCIA 2017 Vintage
Domestic											
TOUG-GS-1											
TC-1											
TOUG-GS-2											
TOUG-GS-3											
TOUG-S-Sec											
TOUG-S-Pri											
TOUG-S-Sub											
TOUG-PA-2											
TOUG-PA-3											
St. Lighting											
Standby - Sec											
Standby - Pri											
Standby - Sub											
System Avg Rate											

PARA Rates (Cumulative) - Adjusted PCIA Rates (Includes Surcharges / Refunds)																					
Rate Group	PCIA 2001 Vintage	PCIA 2004 Vintage	PCIA 2009 Vintage	PCIA 2010 Vintage	PCIA 2011 Vintage	PCIA 2012 Vintage	PCIA 2013 Vintage	PCIA 2014 Vintage	PCIA 2015 Vintage	PCIA 2016 Vintage	PCIA 2017 Vintage	PCIA 2018 Vintage	PCIA 2019 Vintage	PCIA 2020 Vintage	PCIA 2021 Vintage	PCIA 2022 Vintage	PCIA 2023 Vintage	PCIA 2024 Vintage	PCIA 2025 Vintage	PCIA 2026 Vintage	PCIA 2027 Vintage
Domestic	\$ 0.00002	\$ 0.02416	\$ 0.02865	\$ 0.03456	\$ 0.03579	\$ 0.03692	\$ 0.04191	\$ 0.04630	\$ 0.04664	\$ 0.04666	\$ 0.04694	\$ 0.04736	\$ 0.04761	\$ 0.05197	\$ 0.05161	\$ 0.05902	\$ 0.05121	\$ 0.05106	\$ 0.01967	\$ 0.01967	
TOUG-GS-1	\$ 0.00001	\$ 0.00001	\$ 0.01763	\$ 0.02091	\$ 0.02522	\$ 0.02612	\$ 0.02694	\$ 0.03058	\$ 0.03379	\$ 0.03404	\$ 0.03405	\$ 0.03425	\$ 0.03456	\$ 0.03474	\$ 0.03792	\$ 0.03766	\$ 0.03715	\$ 0.03737	\$ 0.03726	\$ 0.01435	\$ 0.01435
TC-1	\$ 0.00001	\$ 0.00001	\$ 0.01837	\$ 0.02179	\$ 0.02628	\$ 0.02722	\$ 0.02808	\$ 0.03187	\$ 0.03521	\$ 0.03547	\$ 0.03549	\$ 0.03570	\$ 0.03602	\$ 0.03621	\$ 0.03952	\$ 0.03925	\$ 0.03872	\$ 0.03894	\$ 0.03883	\$ 0.01496	\$ 0.01496
TOUG-GS-2	\$ 0.00001	\$ 0.00001	\$ 0.01769	\$ 0.02097	\$ 0.02529	\$ 0.02620	\$ 0.02702	\$ 0.03068	\$ 0.03389	\$ 0.03414	\$ 0.03416	\$ 0.03436	\$ 0.03467	\$ 0.03485	\$ 0.03804	\$ 0.03778	\$ 0.03727	\$ 0.03748	\$ 0.03738	\$ 0.01439	\$ 0.01439
TOUG-GS-3	\$ 0.00001	\$ 0.00001	\$ 0.01755	\$ 0.02081	\$ 0.02510	\$ 0.02599	\$ 0.02681	\$ 0.03044	\$ 0.03363	\$ 0.03388	\$ 0.03389	\$ 0.03409	\$ 0.03440	\$ 0.03458	\$ 0.03774	\$ 0.03748	\$ 0.03698	\$ 0.03719	\$ 0.03708	\$ 0.01428	\$ 0.01428
TOUG-Sec	\$ 0.00001	\$ 0.00001	\$ 0.01728	\$ 0.02049	\$ 0.02471	\$ 0.02559	\$ 0.02640	\$ 0.02997	\$ 0.03311	\$ 0.03335	\$ 0.03336	\$ 0.03356	\$ 0.03387	\$ 0.03404	\$ 0.03716	\$ 0.03690	\$ 0.03641	\$ 0.03662	\$ 0.03651	\$ 0.01406	\$ 0.01406
TOUG-S-Pri	\$ 0.00001	\$ 0.00001	\$ 0.01654	\$ 0.01961	\$ 0.02365	\$ 0.02450	\$ 0.02527	\$ 0.02869	\$ 0.03169	\$ 0.03193	\$ 0.03194	\$ 0.03213	\$ 0.03242	\$ 0.03259	\$ 0.03557	\$ 0.03533	\$ 0.03485	\$ 0.03505	\$ 0.03495	\$ 0.01346	\$ 0.01346
TOUG-S-Sub	\$ 0.00001	\$ 0.00001	\$ 0.01573	\$ 0.01865	\$ 0.02249	\$ 0.02330	\$ 0.02403	\$ 0.02728	\$ 0.03014	\$ 0.03036	\$ 0.03037	\$ 0.03055	\$ 0.03083	\$ 0.03099	\$ 0.03383	\$ 0.03360	\$ 0.03314	\$ 0.03333	\$ 0.03324	\$ 0.01280	\$ 0.01280
TOUG-PA-2	\$ 0.00001	\$ 0.00001	\$ 0.01844	\$ 0.02187	\$ 0.02638	\$ 0.02732	\$ 0.02818	\$ 0.03199	\$ 0.03534	\$ 0.03560	\$ 0.03562	\$ 0.03583	\$ 0.03615	\$ 0.03634	\$ 0.03967	\$ 0.03940	\$ 0.03886	\$ 0.03909	\$ 0.03898	\$ 0.01501	\$ 0.01501
TOUG-PA-3	\$ 0.00001	\$ 0.00001	\$ 0.01738	\$ 0.02061	\$ 0.02486	\$ 0.02575	\$ 0.02656	\$ 0.03016	\$ 0.03332	\$ 0.03356	\$ 0.03357	\$ 0.03377	\$ 0.03408	\$ 0.03425	\$ 0.03739	\$ 0.03714	\$ 0.03664	\$ 0.03685	\$ 0.03674	\$ 0.01415	\$ 0.01415
St. Lighting	\$ 0.00001	\$ 0.00001	\$ 0.02104	\$ 0.02495	\$ 0.03010	\$ 0.03117	\$ 0.03215	\$ 0.03650	\$ 0.04033	\$ 0.04062	\$ 0.04064	\$ 0.04088	\$ 0.04125	\$ 0.04146	\$ 0.04426	\$ 0.04495	\$ 0.04454	\$ 0.04460	\$ 0.04447	\$ 0.01713	\$ 0.01713
Standby - Sec	\$ 0.00001	\$ 0.00001	\$ 0.01685	\$ 0.01999	\$ 0.02411	\$ 0.02497	\$ 0.02575	\$ 0.02924	\$ 0.03230	\$ 0.03254	\$ 0.03255	\$ 0.03274	\$ 0.03304	\$ 0.03321	\$ 0.03625	\$ 0.03600	\$ 0.03552	\$ 0.03572	\$ 0.03562	\$ 0.01372	\$ 0.01372
Standby - Pri	\$ 0.00001	\$ 0.00001	\$ 0.01655	\$ 0.01963	\$ 0.02367	\$ 0.02452	\$ 0.02529	\$ 0.02871	\$ 0.03172	\$ 0.03196	\$ 0.03197	\$ 0.03216	\$ 0.03245	\$ 0.03262	\$ 0.03560	\$ 0.03536	\$ 0.03488	\$ 0.03508	\$ 0.03498	\$ 0.01347	\$ 0.01347
Standby - Sub	\$ 0.00001	\$ 0.00001	\$ 0.01569	\$ 0.01863	\$ 0.02245	\$ 0.02325	\$ 0.02398	\$ 0.02722	\$ 0.03008	\$ 0.03030	\$ 0.03031	\$ 0.03049	\$ 0.03076	\$ 0.03092	\$ 0.03376	\$ 0.03352	\$ 0.03307	\$ 0.03326	\$ 0.03317	\$ 0.01277	\$ 0.01277
PCIA System Average	\$ 0.00001	\$ 0.00001	\$ 0.01900	\$ 0.02348	\$ 0.02936	\$ 0.02936	\$ 0.03029	\$ 0.03441	\$ 0.03803	\$ 0.03831	\$ 0.03833	\$ 0.03855	\$ 0.03890	\$ 0.03910	\$ 0.04270	\$ 0.04240	\$ 0.04183	\$ 0.04207	\$ 0.04195	\$ 0.01608	\$ 0.01608

2020 PUBA UC Amount to Collect (\$800)

	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-	\$	-
--	----	---	----	---	----	---	----	---	----	---	----	---	----	---	----	---	----	---	----	---	----	---	----	---

Final Cumulative PCIA/TC Rates - To Be Implemented																					
Rate Group	PCIA 2001 Vintage	PCIA 2004 Vintage	PCIA 2009 Vintage	PCIA 2010 Vintage	PCIA 2011 Vintage	PCIA 2012 Vintage	PCIA 2013 Vintage	PCIA 2014 Vintage	PCIA 2015 Vintage	PCIA 2016 Vintage	PCIA 2017 Vintage	PCIA 2018 Vintage	PCIA 2019 Vintage	PCIA 2020 Vintage	PCIA 2021 Vintage	PCIA 2022 Vintage	PCIA 2023 Vintage	PCIA 2024 Vintage	PCIA 2025 Vintage	PCIA 2026 Vintage	PCIA 2027 Vintage
Domestic	\$ 0.00002	\$ 0.00002	\$ 0.02416	\$ 0.02865	\$ 0.03456	\$ 0.03579	\$ 0.03692	\$ 0.04191	\$ 0.04630	\$ 0.04664	\$ 0.04666	\$ 0.04694	\$ 0.04736	\$ 0.04761	\$ 0.05197	\$ 0.05161	\$ 0.05902	\$ 0.05121	\$ 0.05106	\$ 0.01967	\$ 0.01967
TOUG-GS-1	\$ 0.00001	\$ 0.00001	\$ 0.01763	\$ 0.02091	\$ 0.02522	\$ 0.02612	\$ 0.02694	\$ 0.03058	\$ 0.03379	\$ 0.03404	\$ 0.03405	\$ 0.03425	\$ 0.03456	\$ 0.03474	\$ 0.03792	\$ 0.03766	\$ 0.03715	\$ 0.03737	\$ 0.03726	\$ 0.04345	\$ 0.04345
TOUG-GS-2	\$ 0.00001	\$ 0.00001	\$ 0.01767	\$ 0.02098	\$ 0.02527	\$ 0.02618	\$ 0.02700	\$ 0.03064	\$ 0.03387	\$ 0.03412	\$ 0.03413	\$ 0.03433	\$ 0.03464	\$ 0.03482	\$ 0.03800	\$ 0.03773	\$ 0.03855	\$ 0.03792	\$ 0.03778	\$ 0.04298	\$ 0.04298
TOUG-GS-3	\$ 0.00001	\$ 0.00001	\$ 0.01769	\$ 0.02097	\$ 0.02529	\$ 0.02620	\$ 0.03068	\$ 0.03389	\$ 0.03414	\$ 0.03416	\$ 0.03436	\$ 0.03456	\$ 0.03467	\$ 0.03485	\$ 0.03804	\$ 0.03778	\$ 0.03727	\$ 0.03748	\$ 0.03738	\$ 0.04349	\$ 0.04349
TOUG-GS-4	\$ 0.00001	\$ 0.00001	\$ 0.01755	\$ 0.02081	\$ 0.02510	\$ 0.02599	\$ 0.03044	\$ 0.03365	\$ 0.03388	\$ 0.03389	\$ 0.03396	\$ 0.03409	\$ 0.03440	\$ 0.03458	\$ 0.03774	\$ 0.03748	\$ 0.03698	\$ 0.03719	\$ 0.03708	\$ 0.04328	\$ 0.04328
TOUG-Sub	\$ 0.00001	\$ 0.00001	\$ 0.02049	\$ 0.02371	\$ 0.02849	\$ 0.02927	\$ 0.03426	\$ 0.03690	\$ 0.04039	\$ 0.04126	\$ 0.04126	\$ 0.04146	\$ 0.04166	\$ 0.04186	\$ 0.04500	\$ 0.04473	\$ 0.04889	\$ 0.04449	\$ 0.04434	\$ 0.01968	\$ 0.01968
TOUG-8-P1	\$ 0.00001	\$ 0.00001	\$ 0.01654	\$ 0.01961	\$ 0.02365	\$ 0.02430	\$ 0.02527	\$ 0.02869	\$ 0.03169	\$ 0.03193	\$ 0.03194	\$ 0.03213	\$ 0.03242	\$ 0.03259	\$ 0.03587	\$ 0.03553	\$ 0.03485	\$ 0.03505	\$ 0.03495	\$ 0.01346	\$ 0.01346
TOUG-8-Sub	\$ 0.00001	\$ 0.00001	\$ 0.01573	\$ 0.01865	\$ 0.02249	\$ 0.02305	\$ 0.02423	\$ 0.02728	\$ 0.03014	\$ 0.03036	\$ 0.03037	\$ 0.03055	\$ 0.03083	\$ 0.03099	\$ 0.03383	\$ 0.03360	\$ 0.03314	\$ 0.03333	\$ 0.03324	\$ 0.02800	\$ 0.02800
TOUG-8-P2	\$ 0.00001	\$ 0.00001	\$ 0.01587	\$ 0.01844	\$ 0.02238	\$ 0.02292	\$ 0.02409	\$ 0.02712	\$ 0.02999	\$ 0.03023	\$ 0.03024	\$ 0.03042	\$ 0.03069	\$ 0.03087	\$ 0.03369	\$ 0.03346	\$ 0.03297	\$ 0.03316	\$ 0.03306	\$ 0.02800	\$ 0.02800
TOUG-P-3	\$ 0.00001	\$ 0.00001	\$ 0.01738	\$ 0.02061	\$ 0.02486	\$ 0.02575	\$ 0.02656	\$ 0.03016	\$ 0.03332	\$ 0.03356	\$ 0.03357	\$ 0.03377	\$ 0.03408	\$ 0.03426	\$ 0.03739	\$ 0.03714	\$ 0.03664	\$ 0.03685	\$ 0.03674	\$ 0.04145	\$ 0.04145
SL Lighting	\$ 0.00001	\$ 0.00001	\$ 0.02104	\$ 0.02495	\$ 0.03010	\$ 0.03117	\$ 0.03215	\$ 0.03510	\$ 0.04033	\$ 0.04062	\$ 0.04064	\$ 0.04088	\$ 0.04125	\$ 0.04146	\$ 0.04426	\$ 0.04495	\$ 0.04484	\$ 0.04460	\$ 0.04447	\$ 0.07113	\$ 0.07113
SL Standby - P1	\$ 0.00001	\$ 0.00001	\$ 0.01605	\$ 0.01941	\$ 0.02394	\$ 0.02475	\$ 0.02599	\$ 0.02924	\$ 0.03175	\$ 0.03204	\$ 0.03205	\$ 0.03224	\$ 0.03252	\$ 0.03272	\$ 0.03592	\$ 0.03567	\$ 0.03498	\$ 0.03519	\$ 0.03508	\$ 0.03948	\$ 0.03948
Standby - P1	\$ 0.00001	\$ 0.00001	\$ 0.01655	\$ 0.01963	\$ 0.02367	\$ 0.02452	\$ 0.02529	\$ 0.02871	\$ 0.03172	\$ 0.03196	\$ 0.03197	\$ 0.03216	\$ 0.03248	\$ 0.03262	\$ 0.03546	\$ 0.03536	\$ 0.03488	\$ 0.03508	\$ 0.03498	\$ 0.03747	\$ 0.03747
Standby - Sub	\$ 0.00001	\$ 0.00001	\$ 0.01569	\$ 0.01861	\$ 0.02245	\$ 0.02298	\$ 0.02422	\$ 0.02722	\$ 0.03008	\$ 0.03030	\$ 0.03031	\$ 0.03049	\$ 0.03076	\$ 0.03092	\$ 0.03376	\$ 0.03362	\$ 0.03307	\$ 0.03326	\$ 0.03317	\$ 0.02777	\$ 0.02777
DL PCIA Vintage Average	\$ 0.00001	\$ 0.00001	\$ 0.01800	\$ 0.02148	\$ 0.02634	\$ 0.02704	\$ 0.02829	\$ 0.03241	\$ 0.03603	\$ 0.03631	\$ 0.03633	\$ 0.03655	\$ 0.03699	\$ 0.03719	\$ 0.04270	\$ 0.04240	\$ 0.04183	\$ 0.04207	\$ 0.04195	\$ 0.01608	\$ 0.01608
PCIA Amount to Transfer	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

ERRA CRS Rates - Vintaged Specific Sales Rate Design

2027 ERRA Forecast Application (October)

Rate Group	WF Fund NR (All Vintages) ¹	CTC (For All Vintages)	PCA 2001 Vintage	PCA 2004 Vintage	PCA 2009 Vintage	PCA 2010 Vintage	PCA 2011 Vintage	PCA 2012 Vintage	PCA 2013 Vintage	PCA 2014 Vintage	PCA 2015 Vintage	PCA 2016 Vintage	PCA 2017 Vintage	PCA 2018 Vintage	PCA 2019 Vintage	PCA 2020 Vintage	PCA 2021 Vintage	PCA 2022 Vintage	PCA 2023 Vintage	PCA 2024 Vintage	PCA 2025 Vintage	PCA 2026 Vintage	PCA 2027 Vintage
Domestic	0.00091	0.00003	0.00002	0.00002	0.00002	0.00002	0.01456	0.01579	0.01692	0.04791	0.04630	0.04664	0.04666	0.04694	0.04736	0.04781	0.05197	0.05161	0.05092	0.05121	0.05196	0.05087	0.05097
TOT-GS-1	0.00091	0.00002	0.00001	0.00001	0.00001	0.00001	0.02622	0.02612	0.02694	0.03098	0.03179	0.03484	0.03495	0.03425	0.03456	0.03474	0.03792	0.03766	0.03715	0.03737	0.03726	0.03415	0.03435
TC-1	0.00091	0.00002	0.00001	0.00001	0.00001	0.00001	0.02628	0.02722	0.02808	0.03187	0.03321	0.03547	0.03549	0.03570	0.03602	0.03621	0.03952	0.03925	0.03872	0.03894	0.03883	0.03496	0.03496
TOT-GS-2	0.00091	0.00002	0.00001	0.00001	0.00001	0.00001	0.02529	0.02599	0.02702	0.03068	0.03189	0.03414	0.03416	0.03436	0.03467	0.03485	0.03774	0.03778	0.03727	0.03748	0.03738	0.03439	0.03439
TOT-GS-3	0.00091	0.00002	0.00001	0.00001	0.00001	0.00001	0.01755	0.02100	0.02381	0.03044	0.03161	0.03188	0.03189	0.03409	0.03440	0.03458	0.03774	0.03748	0.03698	0.03719	0.03708	0.03428	0.03428
TOT-S-Sec	0.00091	0.00002	0.00001	0.00001	0.00001	0.00001	0.01728	0.02471	0.02640	0.02997	0.03111	0.03115	0.03136	0.03336	0.03387	0.03404	0.03716	0.03690	0.03641	0.03662	0.03651	0.03406	0.03406
TOT-S-Sub	0.00091	0.00002	0.00001	0.00001	0.00001	0.00001	0.01728	0.02471	0.02640	0.02997	0.03111	0.03115	0.03136	0.03336	0.03387	0.03404	0.03716	0.03690	0.03641	0.03662	0.03651	0.03406	0.03406
TOT-PA-2	0.00091	0.00002	0.00001	0.00001	0.00001	0.00001	0.01844	0.02187	0.02318	0.03199	0.03334	0.03560	0.03562	0.03583	0.03615	0.03624	0.03987	0.03940	0.03886	0.03909	0.03898	0.03501	0.03501
S Lighting	0.00091	0.00002	0.00001	0.00001	0.00001	0.00001	0.02486	0.02575	0.02696	0.03016	0.03132	0.03356	0.03357	0.03377	0.03408	0.03425	0.03739	0.03714	0.03664	0.03685	0.03674	0.03415	0.03415
Standby - Sec	0.00091	0.00002	0.00001	0.00001	0.00001	0.00001	0.02411	0.03117	0.03215	0.03650	0.04033	0.04062	0.04064	0.04088	0.04125	0.04146	0.04526	0.04495	0.04434	0.04460	0.04447	0.03713	0.03713
Standby - Pri	0.00091	0.00002	0.00001	0.00001	0.00001	0.00001	0.02367	0.02542	0.02529	0.02871	0.03172	0.03196	0.03197	0.03274	0.03304	0.03321	0.03625	0.03636	0.03552	0.03572	0.03562	0.03172	0.03172
Standby - Sub	0.00091	0.00002	0.00001	0.00001	0.00001	0.00001	0.02245	0.02523	0.02598	0.02722	0.03008	0.03030	0.03031	0.03049	0.03076	0.03092	0.03376	0.03352	0.03348	0.03326	0.03348	0.03147	0.03147
System Average (System Average)	0.00091	0.00002	0.00001	0.00001	0.00001	0.00001	0.02336	0.02501	0.02506	0.03556	0.03953	0.03736	0.03528	0.04009	0.03577	0.03888	0.03952	0.04091	0.04073	0.04181	0.04108	0.03672	0.03672

Appendix C

TARF Verifications

 SOUTHERN CALIFORNIA EDISON [®] An EDISON INTERNATIONAL [®] Company P.O. Box 800 Rosemead CA 91770	Settlement Contact: [Redacted]	Contract ID: 10145 Payment From: 8/31/2026 Payment To: 8/31/2026 Number of Days: 1 Statement Number: 1074927 Date Prepared:
Contract Manager: [Redacted]		

Total Amount Due from SCE [Redacted] California State Treasury Attention: PO Box 942809 Sacramento CA 94209-0001

Other Fees and Charges		Payment Type	Pay/Rec	Start Date	End Date	Volume	Price	Invoice Amount
Deal #	Fee							
4305896	GHG Auction Allowance Revenue	GHG Auction Allowance Revenue	Pay	08/01/2026	08/31/2026	1,000.00		
Total Fees:								

PPA Total:

Grand Total: \$



Statement Comment:

Verification of Transmission Accelerator Revolving Fund Remittance pursuant to 748.5(d)(1) and D.26-04-036



California Infrastructure and
Economic Development Bank

CONFIDENTIAL INFORMATION DISCLOSED PURSUANT TO D.06-06-006. PUBLIC
DISCLOSURE IS RESTRICTED.

Gavin Newsom
Governor

October 6, 2026
Southern California Edison
[REDACTED]

To whom it may concern:

Board Members:

Dee Dee Myers
Director,
Governor's Office of
Business & Economic
Development

Fiona Ma
State Treasurer

Joe Stephenshaw
Director,
Department of Finance

Toks Omishakin
Secretary,
California State
Transportation Agency

Marc Steinorth
Governor's Appointee

In accordance with the California Public Utilities Commission ("CPUC") Decision 26-04-036, dated April 30, 2026, Southern California Edison ("SCE") is required to remit five percent of Cap-and-Invest Auction proceeds to the California Transmission Accelerator Revolving Fund ("CTARF") for each Cap-and-Invest Auction from July 1, 2026, to July 1, 2031.

The California Infrastructure and Economic Development Bank ("IBank") is the implementing finance agency of CTARF. This letter confirms that the State is in receipt of [REDACTED] from SCE following the Cap-and-Invest Auction dated August 19, 2026. This remittance and the total funds received by the State from SCE designated for CTARF are as follows:

	Encumbered	Unencumbered
Prior Period Transfers	\$ 0.00	\$ 0.00
Plus (Less) Current Period Cap-and-Invest Auction Transfers	\$ 0.00	[REDACTED]
Cumulative Transfers	\$ 0.00	[REDACTED]

CEO & Executive Director:

Andy Nakahata

Office & Mailing Address:
1325 J Street, Suite 1300
Sacramento, CA 95814

(916) 341-6600 Phone
www.IBank.ca.gov

Sincerely,
[REDACTED]

CC: [REDACTED]

CONFIDENTIAL