Decision 19-02-024 February 21, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Southern California Edison Company (U338E) For Approval of Its Forecast 2019 ERRA Proceeding Revenue Requirement.	Application 18-05-003

DECISION ADOPTING SOUTHERN CALIFORNIA EDISON COMPANY'S 2019 ENERGY RESOURCE RECOVERY ACCOUNT AND GREENHOUSE GAS COST AND RECONCILIATION FORECAST IN PART

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DECISION ADOPTING SOUTHERN CALIFORNIA EDISON COMPANY'S 2019 ENERGY RESOURCE RECOVERY ACCOUNT FORECAST AND GREENHOUSE COST AND RECONCILIATION IN PART

Summary

This decision adopts the 2019 forecast revenue requirement for Southern California Edison Company's (SCE) Energy Resource Recovery Account (ERRA) with the exception of $743.429 million in the ERRA Balancing Account, which the Commission will consider in Application (A.) 18-11-009.

The Commission adopts a 2019 forecasted revenue requirement of $4,043.098[1] million. The total forecast includes both revenue requirements and refunds from overcollections and Greenhouse Gas (GHG) auction proceeds. We approve revenue requirements of $4,195.681 million for fuel and purchased power (less the amount of the 2018 brown power true-up) and $299.039 million in GHG Cap-and-Trade costs. The revenue requirements will be offset by a forecast refund of $28.221 million for the Energy Settlements Memorandum Account, a forecast refund of $73.503 million for the New System Generation Balancing Account, and a forecast refund of $349.898 million in GHG auction proceeds.

The Commission also adopts 2019 GHG forecast auction proceeds of $408.536 million ($390.680 million net auction proceeds), with $349.898 million being returned to customers after setting aside funding for clean energy and energy efficiency programs, outreach and administrative expenses, and overcollections. This decision authorizes the forecast amount of $33.00 per

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[1] Includes Franchise Fees and Uncollectibles (FF&U).

household for the California Climate Credit program to be returned to residential customers beginning in 2019.

This decision also approves SCE's Power Charge Indifference Adjustment (PCIA) calculation methodology, after modification for compliance with Decision (D.) 18-10-019, for a total PCIA forecast of $1,108.186 million. Finally, this decision allows SCE to collect termination payments made in 2019 to Coso Geothermal Power Holdings LLC under the termination agreement in A.18-03-010 in this 2019 ERRA forecast and recently authorized in D.18-11-036.

SCE's revenue requirements will be consolidated with the revenue requirement changes under other Commission decisions in the Annual Electric True-up process. The rate changes are effective upon the approval of the Tier 1 advice letter filed in conformance with this Decision.

This proceeding is closed.

1. Factual Background

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

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

As compelled by Pub. Util. Code § 454.5(d)(3) and instituted in D.02-10-062, the balance of the ERRA is not to exceed five percent of the electric utility's actual recorded generation revenues for the prior calendar year, excluding revenues collected for the California Department of Water Resources (CDWR).[3] D.02-10-062 also established a trigger mechanism that requires SCE to file an expedited application when the ERRA balance reaches the four percent threshold, and include a projected account balance in 60 days or more from the date of the filing depending on when the balance will reach the five percent threshold.[4] The expedited application is also required to propose an amortization period for the over or undercollection of not less than 90 days using the Commission's existing allocation methodology.[5] In D.06-06-051, the Commission authorized SCE to notify the Commission of an ERRA Balancing Account trigger point exceedance by Advice Letter (AL), rather than an expedited application, when SCE did not seek a change in rates as a result of the

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[2] D.02-10-062 at 47, 50 and Conclusion of Law (COL) 7.

[3] D.02-10-062 at 64-66, 79 (Ordering Paragraph (OP) #14).

[4] *Id*. at 65-66.

[5] *Id*.

exceedance and the ERRA balancing account was expected to self-correct below the trigger point within 120 days of the AL filing.[6]

In D.06-07-030 (as modified by D.07-01-030 and subsequently refined in D.11-12-018, D.14-10-045 and D.18-10-019), the Commission adopted the total portfolio methodology and market benchmark for determining the above-market costs associated with the utility/CDWR Power Charge as an element of the Costs Responsibility Surcharge (CRS) with the Power Charge Indifference Adjustment (PCIA). The PCIA applies to departing load customers who are responsible for a share of the CDWR power contracts or new generation resource commitments. The PCIA is intended to ensure that departing load customers pay their share of the above-market portion of the CDWR contract and generation resource costs incurred on their behalf, and that bundled customers remained indifferent to customer departures.

The purpose of the total portfolio methodology was to reasonably ensure that bundled customers were indifferent with respect to departing load. Rather than focus on each individual resource cost, the total portfolio method recognized that bundled customers were served from the entire portfolio of commodity resources and that, when load departed, the utility may, in general, offset a portion of the departing load costs through additional market sales.

The electric utilities were also required to incorporate greenhouse gas costs into the generation component of electricity rates through the ERRA process.[7] Incorporating the costs of greenhouse gas (GHG) emissions into rates resulted in

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6 D.06-06-051 at 10 (OP #3).

7 D.12-12-033; D.14-10-033.

a carbon price signal intended to incent an overall decrease in energy consumption and reduction in GHG emissions.[8]

2. Procedural Background

On May 1, 2018, SCE filed its *Application of Southern California Edison Company in its Forecast 2019 Energy Resource Recovery Account (ERRA) Proceeding* (Application) and served associated testimony, in which SCE requested the Commission approve its 2019 forecasted revenue requirement. California Choice Energy Authority (CCEA) and Direct Access Customer Coalition (DACC) filed responses to the Application on June 11, 2018 and June 12, 2018, respectively. The Public Advocates Office of the Public Utilities Commission[9] filed a protest to the Application on June 20, 2018.

On May 10, 2018, Resolution ALJ 176-3416 preliminarily determined that this proceeding was categorized as ratesetting and that hearings were necessary. On June 1, 2018, SCE served supplemental testimony that replaced previous testimony related to its revenue requirement in its entirety.

The assigned Administrative Law Judge (ALJ)(ALJ Kline) held a prehearing conference (PHC) on July 9, 2018 to discuss the scope of the proceeding and to address whether there was need for evidentiary hearings, as well as to develop a procedural timetable for the management of the proceeding.

SCE held a workshop on its testimony on July 19, 2018. Thereafter, the parties filed a joint case management statement on July 26, 2018, indicating no disputed issues of material fact remained. ALJ Kline took evidentiary hearings

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[8] D.14-10-033.

[9] The Office of Ratepayer Advocates was renamed the Public Advocates Office of the Public Utilities Commission pursuant to Senate Bill No. 854, which the Governor approved on June 27, 2018.

off-calendar by ruling on August 24, 2018. On September 21, 2018, SCE and CCEA filed opening briefs.

ALJ Kline granted the Clean Power Alliance's (CPA) motion for party status on September 24, 2018. Parties filed reply briefs on October 19, 2018. On October 24, 2018, ALJ Kline issued a ruling requesting additional information on Advice Letter 3856-E.

On October 29, 2018 and November 2, 2018, ALJ Kline granted the motions for party status of the California Large Energy Consumers Association (CLECA) and the Energy Producers and Users Coalition (EPUC), respectively. SCE served updated testimony (November Update) on November 7, 2018. The Commission's Energy Division hosted a workshop on November 8, 2018 to discuss the updated template for calculating the PCIA as a result of D.18-10-019 (PCIA Track 2 Decision).

CPA, CCEA, EPUC and DACC filed comments on the November Update on November 15, 2018. SCE filed reply comments on the November Update on November 19, 2018.

3. Issues Before the Commission

The issues to be determined are:

1. Whether SCE's requested 2019 ERRA Forecast revenue requirement of $ 3.785 billion is reasonable, including consideration of SCE's forecast of electric sales, electric load, fuel and purchased power expenses and SCE's forecast GHG costs.
2. Whether SCE's forecast of GHG allowance revenue return allocations for energy-intensive trade-exposed (EITE) customers, small business customers and the residential customer California Climate Credit is reasonable.
3. Whether SCE's forecast of GHG revenues and expenses set aside for 1) clean energy and energy efficiency programs

and GHG administration, and 2) customer education and outreach plan costs is reasonable.

4. Whether SCE's forecast and recovery of the costs of Green Tariff Shared Renewables (GTSR) resources complies with the D.15-01-051, including:
   a. procurement of GTSR resources separately from its Renewables Portfolio Standard requirement, and
   b. exclusion of GTSR resources costs used to serve GTSR customers.
5. Whether the calculation methodology for the PCIA and Competition Transition Charge (CTC) are consistent with D.11-12-018 and Resolution E-4475, or other relevant Commission decisions.
6. Whether SCE's calculation of the Cost Allocation Mechanism (CAM) is consistent with D.10-12-035.
7. Whether SCE's request and methods used to determine the items above comply with all applicable rules, regulations, resolutions and decisions for all customer categories.
8. Whether there are any safety considerations raised by this application.

4. Uncontested Issues - Purchased Power, Energy Settlements Memorandum Account, New System Generation Balancing Account, Recorded and Forecast GHG Allowance Proceeds, Expenses, Credits and Costs.

SCE's updated 2019 Forecast Application requests approval of a total ERRA revenue requirement of $4,786.527 million. The request is comprised of proposed fuel and purchased power costs of $4,195.681 million, forecast refunds from the Energy Settlements Memorandum Account (ESMA) of $28.221 million, forecast refunds in the New System Generation Balancing Account (NSGBA) of $73.503 million and a $743.429 million revenue requirement in the ERRA Balancing Account.

SCE's November Update testimony also forecasts GHG Cap-and-Trade costs of $299.039 million. SCE's total projected net GHG auction revenue is in its November Update testimony is $390.680 million.[10] SCE proposes to provide its residential customers with a biannual, on-bill California Climate Credit of $33.00 in 2019.[11] SCE's proposed revenue requirement along with a summary of the forecast revenue adopted in this decision is summarized in the table below (in millions).

Forecast Revenue Requirement	**SCE Proposed**	**Commission Adopted**
Fuel and Purchased Power	$4,195.681	$4,195.681
ERRA Balancing Account	$743.429	(A.18-11-009)
ESMA	-$28.221	-$28.221
NSGBA	-$73.503	-$73.503
GHG Cap-and-Trade Costs	$299.039	$299.039
Net GHG Auction Proceeds	-$390.680	-$390.680
CA Climate Credit, Small Business Returns, EITE, Clean Energy and EE programs, GHG Administrative Expenses	$349.898	$349.898
Total	**$4,786.527**	**$4,043.098**

In its protest, the Public Advocates Office of the Public Utilities Commission stated it intended to investigate the reasonableness of SCE's 2019 forecast, including but not limited to review of the underlying natural gas prices, load, and other cost inputs used to calculate SCE's forecast revenue requirement. DACC's response to the application indicated that its primary interest was

10 Exhibit SCE-4 at 62; SCE Comments on Proposed Decision (PD) at 5 ("The PD should be modified to reduce the proposed $8.952 million set-aside to $2 million, the latter amount to be transferred to the DAC Balancing Account when it is approved in AL 3841.")

11 *Id*. at 56; SCE Comments on PD at 5-6.

calculation and treatment of costs charged to direct access customers, including the PCIA, the CTC and the CAM.

As neither the Public Advocates Office of the Public Utilities Commission nor DACC filed testimony on these issues and all parties agreed that hearings were not necessary, we conclude that the issues presented by the interested parties in their protests have been resolved, with the exception of the PCIA and the ERRA Balancing Account undercollection, as discussed further below. Upon review, the Commission adopts SCE's forecast 2018 ERRA fuel and purchased power costs, ESMA, NSGBA, GHG Cap-and-Trade Costs, and GHG Allowance Revenues as reasonable, as modified by this Decision.

4.1. Fuel and Purchased Power

SCE's forecast fuel and power purchase costs are associated with its resource portfolio and executed contracts from SCE's Local Capacity Requirement (LCR) solicitations in the Western Los Angeles[12] and Moorpark[13] subareas. SCE's resource portfolio consists of 1) utility owned generation (UOG), 2) SCE's purchased power resources and 3) proxy costs from anticipated future solicitations and market purchases. SCE's UOG resources consist of nuclear, natural gas, hydroelectric, fuel cells and renewable generation resources. SCE's purchased power resources consist of combined heat and power (CHP) and renewable resources, inter-utility contracts and bilateral contracts.

[12] D.15-11-041.

[13] D.16-05-050.

SCE's 2019 total estimated fuel and purchased power revenue requirement is $4,195.681 million, as set out in the table below (in millions): [14]

Generation Fuel and Purchased Power Requirement	$3,639.325
New System Generation Revenue Requirement	$449.001
Distribution – Base Revenue Requirement Balancing Account (Demand Response Auction Mechanism/Preferred Resources Pilot)	$11.967
Local Capacity Requirement Fuel and Purchased Power Revenue Requirement	$91.081
Spent Nuclear Fuel Storage Revenue Requirement	$4.306
Total	**$4,195.681**

SCE's detailed costs for the fuel and purchased power in the aforementioned resources is confidential and will not be enumerated herein.

On March 19, 2018, SCE submitted an application to terminate two Power Purchase Agreements (PPAs) with Coso Geothermal Power Holdings LLC (the Coso termination agreement).[15] Since SCE had not obtained regulatory approval of the Coso termination agreement at the time of SCE's June testimony filing, SCE's June testimony reflected the contract costs and market generation revenues for the two geothermal PPAs but not the cost of the PPA termination payment ("Coso in" model).[16]

In response to the assigned ALJ's issuance of proposed decision in A.18-03-010 on October 30, 2018 granting the Coso termination agreement, SCE's November Update reflected a $100 million termination payment in 2019, but not the contract costs and market generation revenues from the PPAs ("Coso out"

[14] Exhibit SCE-4 at 70.

[15] A.18-03-010.

[16] *Id*. at 31-32.

model) based on what SCE considered to be regulatory certainty on the Coso termination agreement.[17] On November 29, 2018, the Commission approved SCE's Application for termination of the Coso PPAs, including SCE's proposal to include the costs of the Coso Termination Agreement in the Total Portfolio Costs used to set the 2019, 2020 and 21021 CTC and PCIA under the "Coso out" model. However, the final decision for the Coso termination agreement orders all recovery for the contract termination in the 2020 and 2021 ERRA forecast proceedings.[18] This decision clarifies that SCE can collect the costs for termination payments made in 2019 under the Coso termination agreement in the 2019 ERRA Forecast, and SCE's request for revenue recovery under the "Coso out" model is properly included herein.

No parties opposed or commented on SCE's fuel and purchased power revenue requirement in the November Update. Upon review, the Commission finds SCE's 2019 forecast revenue requirement for fuel and purchased power reasonable.

4.2. Green Tariff Shared Renewables Program and Enhanced Community Renewables Program

In 2013, California enacted the Green Tariff Shared Renewables (GTSR) program established in Senate Bill (SB) 43. On January 29, 2015, the Commission issued D.15-01-051, which implements SB 43 by adopting program requirements for the electric utilities' GTSR programs. The GTSR program provides customers two options for obtaining a greater mix of renewable energy.[19] Under the Green

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[17] *Id*.

[18] D.18-11-036 (OP 1); A.18-03-010.

[19] D.15-01-051.

Tariff option, customers may choose either a 50% or 100% option for the mix of renewable energy with a corresponding increase in their generation rate. Under the enhanced community renewables option, customers may support local renewable energy projects agreements with third party developers.

SCE forecasts 10,296,441 KWh of participation through the green tariff option and 699,593 KWh of participation through the enhanced community renewables option.[20] SCE calculated the procurement costs for GTSR separately and apart from CHP and Renewables costs. Upon review, the Commission finds SCE's 2019 forecast calculation for the GTSR and Enhanced Community Renewables programs reasonable and in compliance with D.15-01-051.

4.3. Energy Settlements Memorandum Account

The Energy Settlements Memorandum Account (ESMA) tracks refunds from generators who overcharged SCE for electricity during the 2000-2001 California Energy Crisis. The Litigation Costs Tracking Account is a subaccount in the ESMA which tracks litigation costs "set-aside" in Federal Energy Regulatory Commission investigation settlement agreements and actual litigation costs incurred by SCE.[21] Accounting for both refunds and litigation costs, SCE estimates a 2019 overcollection in the ESMA of $28.221 million.

No parties opposed or commented on SCE's ESMA balance in the November Update. Upon consideration, the Commission finds SCE's proposed 2019 ESMA balance is reasonable.

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[20] Exhibit SCE-4 at 38.

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

4.4. New System Generation Balancing Account

In D.06-07-029, as modified by D.10-12-035 and SB 695, the Commission adopted a cost-allocation mechanism (CAM) to allocate the costs electric utilities incur to meet resource adequacy requirements on behalf of customers in an electric utility's service territory. SCE may also allocate costs associated with CHP generation procured on behalf of direct access customer's Electric Service Providers and Community Choice Aggregators (CCAs) pursuant to D.10-12-035.

The New System Generation Balancing Account (NSGBA) records the benefits and costs of power purchase agreements associated with new generation resources. SCE forecasts a 2019 CAM-related revenue requirement $449.001 million in 2019.[22] SCE also forecast a net overcollection of $73.503 million in the NSGBA for 2019.[23]

No parties opposed or commented on SCE's NSGBA balance in the November Update. Upon consideration, the Commission finds SCE's proposed 2019 NSGBA balance is reasonable.

4.5. Greenhouse Gas Forecast Costs, Revenues and Reconciliation

The Commission adopted standard procedures for electric utilities to request greenhouse gas forecast revenue and reconciliation filed after 2013 in D.14-10-033. The decision also adopted Confidentiality Protocols for Cap-and-Trade related data and required the utilities to use a proxy price in their forecasts. Finally, the decision required the utilities to file GHG Forecast Revenue and Reconciliation Applications annually as part of their ERRA forecast

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22 *Id*. at 79.

23 *Id*. at 70.

applications. We use the standards adopted in D.14-10-033 to review SCE's current Application (A.) 18-05-003 to determine the reasonableness of both the recorded and forecasted variables.[24]

SCE's total GHG Cap-and-Trade costs are $299.039 million. SCE also proposes to return $349.898 million in net GHG auction proceed revenues to SCE customers.[25] SCE's net GHG revenues consist of the following: 1) recorded and forecast GHG auction allowance revenues, 2) administrative and customer outreach expenses, and 3) expenses for approved incremental Energy Efficiency (EE) and Clean Energy programs. A summary of SCE's proposed GHG allowance revenues and this decision's adopted GHG allowance revenues are provided in the table below (in millions):[26]

Program	**Budget**
GHG auction revenues (in $ million)	
1. 2019 Forecast GHG auction allowance revenue	$408.536
2. 2018 Forecast GHG auction undercollection	- $22.599
3. 2019 Forecast Franchise Fees and Uncollectibles (FF&U)	$4.742
Subtotal	$390.680
Expenses (in $ million)	
Outreach and Administrative Expenses	$0.200
FF&U	$0.002
Subtotal	- $0.202

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

25 Exhibit SCE-4 at 55.

26 *Id.* at 66.

Clean Energy and Energy Efficiency Programs 1. 2019 Solar on Multifamily Affordable Housing (SOMAH) 2. 2018 SOMAH True up 3. 2019 Disadvantaged Communities- Solar Affordable Housing (DAC-SASH) 4. 2019 DAC-GT and CSGT	- $40.853 $6.874 - $4.600 -2.000
Total	**$349.898**

SCE requested to distribute the $349.898 million to 1) Emissions Intensive and Trade Exposed (EITE) customer returns, 2) small business returns and 3) residential customers through the California Climate Credit, as summarized in the table below.[27]

Program	Budget
EITE	$25,885
Small Business returns	$19,573
Residential California Climate Credit	$304,440
Total	**$349.898**

Finally, this decision adopts a biannual residential California Climate Credit of $33 per eligible household.

4.5.1. Greenhouse Gas Costs

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

[27] *Id.*

SCE's November Update forecasts $299.039 million in 2019 GHG costs, including FF&U, which is calculated using the Intercontinental Exchange settlement price as of September 21, 2018, which is $16.33/metric ton (MT).[28] SCE's GHG costs are summarized in the table below (in millions):[29]

2019 Forecast GHG costs	$295.608
FF&U	$3.431
Total	**$ 299.039**

No parties opposed or commented on SCE's GHG costs as provided in the November Update. Upon consideration, the Commission finds SCE's 2019 forecast GHG cost is reasonable and complies with the standards set in D.14-10-033.

4.5.2. Greenhouse Gas Allowance Proceeds

The recorded and forecast GHG allowance proceeds are the proceeds received by a utility as a result of selling the allowances allocated to ratepayers by the state. SCE's forecasted its GHG allowance revenue by multiply a forecast proxy GHG allowance price of $16.33/MT by the total volume of allowances the California Air Resources Board (ARB) allocated to SCE (25,017,535 MT CO_{2e}).[30] SCE's total forecast 2019 GHG allowance is $408.536 million. The 2019 forecast is adjusted to reflect $22.599 million in undercollected funds due to the difference between actual and forecast auction allowance revenues in 2018.[31] In addition,

[28] *Id*. at 56.

[29] *Id*.

[30] *Id*. at 62.

[31] *Id*. at 65.

SCE forecasts $4.742 million in FF&U in 2019.[32] Upon consideration, the Commission finds SCE's 2019 forecast allowance proceeds and costs reasonable.

4.5.3. Administrative and Customer Outreach Expenses

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

SCE's 2018 recorded administrative and customer outreach costs were $192,661. SCE's 2019 forecast for administrative and customer outreach expenses is $200,000, consisting of primarily "marketing, education and outreach costs associated with the April and October climate credits."[33] No parties opposed or commented on SCE's 2019 forecast of administrative and customer outreach expenses as proposed in the November Update. Upon consideration, the Commission finds SCE's 2019 forecast administrative and customer outreach expense costs reasonable.

4.5.4. Incremental Clean Energy and Energy Efficiency Programs

Under Pub. Util. Code 748.5(c), the Commission may allocate up to 15% of the revenue received by an electric corporation from its sales of allocated GHG allowances to specific Clean Energy and EE projects that are not funded by another source and are already approved by the Commission. SCE's 2019 forecast 15% allowance is $61.280 million.[34] The funding for Clean Energy and EE programs is summarized in the table below (in millions).

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32 *Id*.

33 *Id*. at 61.

34 *Id*. at 63, fn 62.

2019 SOMAH	$40.854
2018 SOMAH True Up	-$6.874
2019 DAC-SASH	$4.600
DAC-GT and CSGT	$2.000
Remaining funds	$20.701
Total	**$61.280**

D.17-12-022 adopted SCE's set-aside amount for the SOMAH program as SCE's share of total GHG auction sale proceeds over four quarterly auctions. SCE's 2018 recorded SOMAH set-aside was $39.1 million and its ERRA 2019 forecast set aside is $40.854 million.[35] Upon review, the Commission finds SCE's set aside for SOMAH is reasonable and complies with D.17-12-022.

In D.18-06-027, the Commission created the DAC-SASH, the DAC-GT, and the CSGT programs to incentive the installation of solar generating systems in low-income households. D.18-06-027 set an annual $10 million budget for the DAC-SASH program. D.18-06-027 set no budget for the DAC-GT or CSGT programs, but authorized utilities to funds both programs first through available GHG allowance proceeds, and then through public purpose program funds if the GHG allowance funds were exhausted.

SCE proposed to set-aside $4.600 million, its share of the annual $10 million budget, for the DAC-SASH program. SCE also proposes to set aside $2 million in GHG allowance funding for the DAC-GT and the CSGT programs.[36] Upon consideration, the Commission finds SCE's set aside for DAC-SASH, DAC-GT and CSGT reasonable and in compliance with D.18-06-027.

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[35] *Id*. at 64.

[36] SCE's Comments on PD at 4-6.

4.5.5. Emissions-Intensive and Trade Exposed Emissions Customer Return

A portion of the GHG allowance proceeds are returned to customers who qualify as Emissions-Intensive and Trade Exposed (EITE). The EITE customer return is based on formulas determined in R.11-03-012 and made to EITE customers once per year.

SCE's 2018 recorded EITE customer return was $25.885 million and SCE's 2019 forecast EITE customer return is $25.885 million.[37] No parties opposed or commented on SCE's 2019 forecast EITE customer return as proposed in the November Update. Upon consideration, the Commission finds SCE's forecast 2019 EITE return is reasonable for the purpose of calculating the proceeds available to EITE customers.

4.5.6. Small Business Return

Using a methodology adopted in R.11-03-012, a portion of allowance proceeds are returned to customers who meet the definition of a small business as determined in R.11-03-012.[38] The forecast Small Business Return is volumetric; it is calculated using the forecast GHG Cost (*see* section 4.5.1 above) and the volume of electricity used by the customer and is returned as a credit to the delivery component of the customer's monthly bill.

SCE's 2018 recorded Small Business Volumetric Return is $27.787 million and its 2019 forecast Small Business Volumetric Return is $19.573 million.[39] The

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[37] *Id*. at 66.

[38] D.12-12-033 sets forth an overview of the methodology which is sufficient for purposes of forecasting the small business customer return in 2014. D.13-12-012 adopted a specific methodology.

[39] Exhibit SCE-4 at 66.

decrease in the Small Business Volumetric Return from 2018 to 2019 reflects a decrease of $25.216 million between the forecast and actual 2018 Cap-and-Trade costs.[40] No parties opposed or commented on SCE's 2019 Small Business Volumetric Return in the November Update. Upon consideration, the Commission finds SCE's forecast 2019 Small Business Volumetric Return is reasonable for the purpose of calculating the proceeds available to customers.

The exact credit per customer will be determined by multiplying the Cap-and-Trade unit cost for the customer's rate schedule by the customer's monthly usage and then adjusting by the Industry Assistance Factors determined in D.13-12-002.[41]

4.5.7. Residential California Climate Credit

The California Climate Credit is distributed to residential households after all applicable GHG-related expenses and customer returns have been made. It appears as a credit on the customer's bill twice per year. The California Climate Credit is not related to the volume of electricity used by the household; each household within a utility's territory receives the same California Climate Credit.

SCE's 2019 forecast of the total number of households eligible for the residential California Climate Credit is 4,576,944. SCE's proposed residential California Climate Credit is $33.00, to be distributed as a credit on residential customers' bills in April and October of 2019.[42] No parties opposed or commented on SCE's residential California Climate Credit in the November

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[40] *Id*. at 67.

[41] *See* D.13-12-002, Table 2 of Appendix 2.

[42] Exhibit SCE-4 at 65.

Update. Upon consideration, the Commission finds SCE's proposed residential California Climate Credit reasonable.

5. 2018 ERRA Balancing Account Undercollection Proposal

In its November Update, SCE requests recovery of a $743.429 million revenue requirement for undercollection in its ERRA Balancing Account. This represents a $644.883 million increase from SCE's June 1, 2018 testimony, which showed an ERRA Balancing Account undercollection of $98.545 million.[43] SCE states that the undercollection is primarily due to a dramatic increase in natural gas and wholesale market prices in late July and early August, caused by constraints on the SoCalGas natural gas local distribution system.[44]

In AL 3856-E, dated August 31, 2018, SCE first notified the Commission that SCE's ERRA balance surpassed the four percent trigger point[45] as of May 31, 2018 and surpassed the Assembly Bill (AB) 57 five percent threshold[46] as of July 31, 2018. In AL 3856-E, SCE proposed to address the undercollected balance in the ERRA forecast through its 2019 rates rather than through an expedited application, for Commission consideration as part of its November Update in this forecast proceeding.[47] AL 3856-E proposed to collect the undercollection through a pro-rata apportionment in 2019 to bundled customer rates and 2018 and 2019 departing load customers.

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43 *Id*. at 11.

44 *Id*. at 4-7.

45 For 2018, SCE's four percent trigger point amount is $197.179 million. (AL 3856-E at 1; *see also* AL 3751-E.)

46 For 2018, SCE's five percent threshold is $246.473 million. (*Id.*)

47 AL 3856-E at 3.

On October 30, 2018, the Commission's Energy Division rejected AL 3856-E for failure to comply with the Commission's trigger application requirements. On November 13, 2018, SCE filed an expedited application (A.18-11-009) notifying the Commission of the four percent trigger exceedance, as previously disclosed in AL 3856-E.

SCE's November Update testimony elaborates on SCE's proposal to amortize the undercollected balance in 2019 forecast rates. Rather than collecting the $743.429 million incurred in 2018 through SCE's bundled service customers, SCE seeks to apportion some of those costs onto departing load customers through the PCIA. SCE reasons that the undercollection in 2018 was incurred on behalf of all its bundled customers in 2018. Since approximately 30 communities are expected to begin CCA services in 2019, SCE argues that the remaining bundled service customers would pay an inequitable share of the 2018 undercollection if some portion was not paid by departing load customers, in violation of Pub. Util. Code § 366.1(f).[48] SCE estimates 2018 and 2019 departing load customers should bear $161 million of the $743 million revenue requirement, representing 23% of the undercollection.[49] Therefore, SCE seeks Commission approval to include the 2018 ERRA Balancing Account undercollection as a one-time adjustment to the 2019 PCIA rates charged to 2018 and 2019 vintage customers. SCE calculates that the rate impact of recovering the 2018 undercollection from all customers in 2019 who received bundled

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[48] Exhibit SCE-4 at 90.

[49] *Id*. at 8.

service in 2018 is approximately 1.1¢/kWh.[50] Under SCE's proposal, SCE seeks to increase the 2019 PCIA rate for departing load customers by 1.1¢/kWh.[51]

DACC, EPUC, CCEA and CPA oppose SCE's proposal for shifting a portion of the undercollection to the 2018 and 2019 PCIA vintage. DACC objects to SCE's proposal as procedurally improper because such an apportionment should properly be, but never was, considered in any past proposed future phases of the existing PCIA rulemaking.[52] DACC argues that if the Commission were to contemplate a true up of the ERRA balancing account, it should not do so on an ad hoc basis in an ERRA forecast proceeding, but rather in a rulemaking which considers all other balancing accounts affecting the PCIA.[53] DACC further argues that Pacific Gas and Electric Company (PG&E) has similarly experienced load departures due to the launch of CCAs and SCE has experienced load departure due to DA, without prorating the ERRA Balancing Account.[54]

EPUC is concerned its members will be heavily impacted by the rate increase they will experience as a result of the undercollection and request further opportunity to review the undercollection prior to a Commission decision to place it in rates.[55] EPUC requests additional time to review, conduct

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50 *Id*. at 5.

51 *Id*.

52 DACC Response to November Update at 2.

53 *Id*. at 2-4.

54 *Id*. at 3.

55 EPUC Response to November Update at 3-4.

discovery and investigate the reasonableness of SCE's actions related to the undercollection.[56]

CCEA and CPA (collectively the "SoCalCCAs") object to a Commission determination on SCE's undercollection proposal through the November Update because it is not supported by past practice or any Commission decision.[57] The SoCalCCAs request further Commission investigation into SCE's procurement and hedging activities prior to a determination on amortization of the ERRA Balancing Account.[58]

SCE does not agree that its undercollection proposal is procedurally irregular or fails to conform to D.18-10-019.[59] SCE, however, is amenable to further discovery, testimony and briefing on the ERRA Balancing Account undercollection.[60] In reply comments to the November Update, SCE proposes a procedural schedule which allows for a final decision by the February 21, 2019 agenda meeting.[61]

The Commission has a short deadline for responses to the November Update, with parties granted eight days to provide comments and four days for reply comments. The significant increase of SCE's ERRA Balance Account undercollection from its June 1, 2018 updated testimony along with SCE's proposal to prorate the ERRA balance undercollection to 2018 and 2019

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[56] *Id*. at 2.

[57] Joint Comments of the CCEA and CPA on November 7, 2018 Update Filing (SoCalCCA Comments on November Update) at 4-5.

[58] *Id*. at 5-9.

[59] SCE's Reply Comments on November Update at 2-9.

[60] *Id*. at 2-4.

[61] *Id*. at 3.

vintage departing load customers warrants further investigation and will be considered in SCE's trigger application (A.18-11-009), dated November 13, 2018, to recover the same revenue requirement. Moreover, since the ERRA Balancing Account undercollection will be considered separately, it should not be used in PCIA calculations (i.e. the Incremental Undercollection Rate should be 0) in this proceeding.

6. Cost Responsibility Surcharge

Departing load customers[62] pay the Cost Responsibility Surcharge (CRS) through the CTC and the PCIA to maintain bundled service customer indifference. SCE's May 1 and June 1, 2018 CTC and PCIA values were calculated under the methodology set by the Commission in D.06-07-030, and subsequently refined in D.11-12-018 and D.14-10-045. SCE's November Update testimony significantly altered the calculation of the CTC and the PCIA to reflect the revised methodology adopted in D.18-10-019.

SCE modified its indifference charge in response to D.18-10-019 with the following:

- Modification of the Green Market Price benchmark (MPB) and capacity MPB;
- Re-inclusion of the Mountainview Generating Station into the CRS-eligible portfolio;
- Reflection of a forecast zero or *de minimis* value for capacity in excess of bundled service customers' compliance requirements that is also expected to remain unsold;
- Modification of the revenue allocators used to allocate the vintage Indifference Amounts, also referred to as the

[62] Departing load customers include direct access, customer generation departing load, community aggregation, and community choice aggregation customers.

Vintaged Portfolio Allocation Balancing Account (PABA) revenue requirements from the "Top 100" hours revenue allocator factors to the "generation revenue" allocator factors; also modifying the forecast billing determinants used to set the final CTC and the vintaged PCIA rates from system kWh to vintage kWh; and

- Proposal to allocate a pro-rata share of the ERRA Balancing Account undercollection to 2018 and 2019 departing load customers.[63]

The Commission's Energy Division staff approved SCE's modified PCIA workpaper template per D.18-10-019 on October 24, 2018. SCE served the modified workpaper on the service list for this proceeding on October 31, 2018.

Of the changes resulting from D.18-10-019, parties commented on four issues related to the PCIA, including 1) the PCIA Revenue Allocation Factors, 2) assignment of a zero value for capacity expected to remain unsold, 3) the failure to incorporate a true-up for revenue realized through the 2017 Tax Reform Act, 4) applicability of the brown power true up to the 2019 ERRA forecast and 5) issues related to SCE's proposal to prorate the ERRA Balancing Account undercollection to 2018 and 2019 vintage departing load customers (this last item is addressed in Section 5, above).

This decision approves SCE's PCIA methodology, with the revenue allocation methodology change discussed in Section 6.1, and authorizes SCE's PCIA collection forecast of $1,108.186 million.

6.1. Revenue Allocation Methodology

The SoCalCCAs and DACC are concerned about SCE's PCIA revenue allocation methodology. The SoCalCCAs do not object to SCE's approach to

[63] Exhibit SCE-4 at 81-82.

allocating PCIA-eligible costs among vintages and customer classes, but only on an interim basis. The SoCalCCAs state that the revenue allocation factor methodology should be refined through additional workshops in the PCIA proceeding. They also point out that SCE's general revenue allocation method is inconsistent with the revenue allocation used to amortize the ERRA Balancing Account undercollection and should be reconciled.[64]

Similarly, DACC argues that SCE's creation of actual rates from the calculated PCIA is flawed. DACC states that the revenue allocators do not comport with D.18-10-019 because PG&E, SCE, and San Diego Gas and Electric Company (SDG&E) all utilize different methodologies even though D.18-10-019 mandates a consistent approach.[65]

DACC also expressed concerns over SCE's workpapers, stating they do not appropriately account for the volume of DA load in pre-2015 vintages. For example, DACC contends that there was 7,764 GWh of DA load in 2009, while the workpaper only accounts for 2,571 GWh.[66] DACC argues that more time is needed to review the workpapers for any other obvious errors.[67]

SCE states that the SoCal CCA's proposal to adopt SCE's revenue allocation methodology on an interim basis, pending refinement and standardization across PG&E, SCE and SDG&E through Commission workshops, is reasonable.[68] SCE objects to DACC's claim that SCE's revenue

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64 SoCalCCAs Comments on November Update at 18-19.

65 DACC Response to November Update (DACC Comments on November Update) at 4-6.

66 DACC Comments on November Update at 6.

67 *Id*. at 7.

68 SCE Reply Comments on November Update at 14.

allocation factors are flawed, arguing the legitimacy of several PCIA components, and suggesting a meet-and-confer process with DACC to further discuss SCE's revenue allocation methodology.[69]

Prior to the D.18-10-019, vintage indifference amounts for the PCIA were allocated to rate groups based on the contribution of each rate group to the highest 100 hours of system load (Top 100 Hours Methodology). D.18-10-019 adopted a new methodology which allocated the vintaged Indifference Amounts to rate groups using the generation revenue factors allocated to bundled service customers.[70] The purpose of the new methodology was to assign revenue allocation to departing load customers in a manner consistent with the revenue allocation factors utilities used to allocate generation costs to the utilities' bundled service customers.[71]

SCE changed its allocation process in the November Update by modifying its billing determinants based on departed load customers.[72] Prior to D.18-10-019 (i.e. in the June testimony), SCE calculated its billing determinants cumulatively. It divided each rate class's Indifference Amount by the forecasted amount of energy (in kWh) for that class to calculate the PCIA rate (in $/kWh).[73] In the November Update, SCE calculated its billing determinants incrementally. SCE subtracting out the prior year's vintage departed customer load (leaving only the forecasted load of the bundled customers who remained in that vintage) prior to

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[69] *Id*. at 13.

[70] D.18-10-019 at 149, 153 (OP 4, 15).

[71] *Id*.

[72] Exhibit SCE-4 Workpapers, Ch. IX, PCIA (Witness D. Wong), "Rate Design Calcs by Vintage" tab.

[73] Exhibit SCE-1 Workpapers, CRS (Witness D. Wong), "Indifference Rate Calculation" tab.

dividing each rate class's Indifference Amount by the forecasted amount of energy.[74] CLECA supports SCE's use of incremental billing determinants, and urges the Commission to adopt SCE's methodology or promptly address this issue in a second phase of this ERRA proceeding to avoid an ERRA undercollection in 2019.[75]

D.18-10-019 was silent with respect to billing determinant modifications and this ERRA forecast proceeding is not the proper venue to consider PCIA methodology changes beyond those necessary to implement D.18-10-019 for 2019. Accordingly, SCE shall continue to use system-level billing determinants in its PCIA forecast for this 2019 ERRA forecast proceeding.[76]

SCE made another change to the PCIA allocation methodology in its November Update by allocating the vintaged Indifference Amounts to rate groups using generation revenue allocation factors, then dividing this by the forecast billing determinants to set the final CTC and PCIA rates.[77] While parties, including SCE, acknowledge that additional refinement may be warranted to achieve greater consistency among utilities implementing the revenue allocation, this decision finds that SCE complied with D.18-10-019 Ordering Paragraph 4 by setting its revenue allocation factors for vintaged Indifference Amounts consistent with the factors used to allocate generation costs to bundled service customers. SCE's revenue factor allocation methodology as submitted in the

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74 Exhibit SCE-4 Workpapers, Ch. IX, PCIA (Witness D. Wong), "Rate Design Calcs by Vintage" tab.

75 Opening Comments of CLECA on PD at 2-4.

76 To preserve the allocators (discussed below), the system-level billing determinants should be entered into the PCIA Workbook in the Forecast Sales Table in the "Indifference Rate Calculation" tab of Exhibit SCE-4 Workpapers, Ch. IX, PCIA (Witness D. Wong).

77 Exhibit SCE-4 at 88-90.

November Update PCIA worksheet is reasonable for the purposes of this 2019 ERRA forecast. Refinements to the PCIA methodology are properly addressed through the PCIA rulemaking (R.17-06-026).

The Commission finds DACC's concern over the inaccuracy of the workpaper titled "Recorded DA Sales by Vintage" stems from a misunderstanding of the DA load representation. SCE allocates the total DA load in the workpapers based on the current vintages of DA load in its existing portfolio, rather than reflecting the total DA load in existence historically. Thereby, the total DA load classified as "continuous," "2001" and "2004" equals 2,571 GWh because this is the current composition of DA load in SCE's current portfolio. Accordingly, the Commission does not find that SCE incorrectly allocated DA load in its PCIA calculation.

6.2. Assignment of Excess Resource Adequacy Capacity Price

The SoCalCCAs object to SCE's assignment of a zero price to the Resource Adequacy (RA) capacity expected to be unsold in each individual month in SCE's updated PCIA worksheets as contrary to D.18-10-019.[78] CPA states that D.18-10-019 specifies the use of a zero or *de minimis* value for excess capacity expected to remain unsold only for the purpose of calculating the brown power, renewable portfolio standard and RA benchmarks.[79] CPA argues that D.18-10-019 requires the Energy Division to use "the weighted average system and local RA prices in the most recent RA Report" to calculate the RA Adder in

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[78] SoCalCCAs Comments on November Update at 15-18.

[79] CPA Comments on PD at 6.

2019. [80] CPA is also concerned about SCE's proposed assignment of a zero value to more recent departing load vintages.[81]

SCE argues that D.18-10-019 allows SCE to assign an excess RA expected to remain unsold a value of zero or a *de minimis* price for the purpose of setting the ERRA forecast, and that SCE will true-up the value of excess capacity sold in 2019 as part of the 2019 ERRA compliance proceeding.[82] SCE argues that it is "appropriate to assign any unsold 'long' positions to the most recent departing load vintages first" because RA purchases are generally short-term in nature.[83]

The Commission finds it reasonable to allow SCE to value excess capacity expected to remain unsold at a zero value in this SCE 2019 ERRA forecast. D.18-10-019 (OP 1)[84] authorizes the valuation of excess capacity expected to remain unsold for the purpose of calculating the RA Adder, and prior Commission decisions related to the PCIA are silent with regard to valuing excess capacity expected to remain unsold when calculating the total portfolio costs the utility is expected to incur.[85]

SCE's assignment of a zero price for the value of RA capacity expected to remain unsold is consistent with the Commission's adopted PCIA methodology

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80 *Id*. at 6-7.

81 *Id*. at 7.

82 SCE Reply Comments on November Update at 9-10.

83 SCE Reply Comments on PD at 4.

84 D.18-10-019 OP 1, ("The RA Adder shall be calculated using purchase and sales prices from IOU, CCA, and Electric Service Provider (ESP) transactions made during (year n-1) for deliveries in (year n). A zero or *de minimis* price shall be assigned to capacity expected to remain unsold. The RA Adder shall be calculated in a manner that reflects the three types of RA capacity: system, local, and flexible. For the RA Adder only, the Energy Division shall use the weighted average system and local RA prices in the most recent annual RA report.")

85 D.18-10-019 at 142 (FOF #4).

when calculating the total portfolio costs in SCE's 2019 ERRA forecast, and distinguishable from valuation of capacity expected to be sold. SCE must true-up the value of any capacity expected to remain unsold but which was sold in the forecast year.

6.3. True-Up for Realized 2017 Tax Reform Act Savings

The SoCal CCAs argue that SCE's PCIA calculation should incorporate SCE's savings from the 2017 Tax Reform Savings Act.[86] SCE replies that the Commission will determine the impact of the 2017 Tax Reform Act on SCE's revenue requirement as part of SCE's General Rate Case (GRC) Phase I.[87] SCE states that it will update the PCIA in conformance with any final Commission decision in the GRC Phase I proceeding.[88]

The Commission confirms that SCE's revenue requirement adjustment for the 2017 Tax Reform Act will be determined through a decision in A.16-09-001. Accordingly, it is premature to assign a revenue requirement due to the 2017 Tax Reform Act in this ERRA forecast proceeding. Any discrepancies between the forecast and actual value of SCE's PCIA portfolio will be trued-up as part of SCE's 2019 ERRA Compliance proceeding. Accordingly, SCE's calculation of the PCIA without accounting for the 2017 Tax Reform Act is reasonable in setting SCE's 2019 ERRA forecast.

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86 SoCalCCAs Comments on November Update at 19.

87 SCE Reply Comments on November Update at 14.

88 *Id*.

6.4. Brown Power True-Up

The SoCalCCAs request the Commission grant a contemporaneous true-up of 2018 brown power costs if the Commission grants amortization of the 2018 undercollection for 2018 and 2019 vintage departing load customers.[89] Separately, CPA argues that failure to implement the brown power true-up for 2018 is inconsistent with D.18-10-019, requires additional support and will increase costs for departing load customers by $88 million in 2019.[90] CPA argues that the Commission's deferral of the ERRA Balance undercollection to consideration in A.18-11-009 disadvantages CPA by creating an additional cost shift from bundled to departing load customers.[91] SCE argues that the Pacific Gas and Electric 2019 ERRA forecast proceeding denies the brown power true up as a matter of law, based on the PCIA decision (D.18-10-019) applying prospectively.[92]

SCE misstates what we held in the PCIA decision and the pending PG&E 2019 ERRA forecast proceeding. D.18-10-019 requires "a true-up mechanism for the brown power index to reflect actual values realized in market transactions for the subject year should be adopted to ensure that bundled and departing load customers pay equitably (*i.e.,* pro rata) for non-RA, non-RPS PCIA-eligible resources."[93] The PCIA decision does not prohibit a true-up of brown power for the 2018 subject year. Furthermore, D.18.10.019 also states that, for now, the

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89 *Id*. at 12-13.

90 CPA Comments on PD at 2-3.

91 *Id*. at 3.

92 92 SCE Comments on the PD at 2.

93 D.18-10-019 COL 16.

true-up shall be limited to brown power.[94] Implementing a true-up of 2018 brown power by this decision meets the requirements of the PCIA decision in a timely manner. Therefore, SCE shall implement a 2018 brown power true-up as a result of this decision.

SCE shall calculate the true-up for 2018, or until its PABA is established and approved, by applying actual 2018 market prices to actual PCIA-eligible generation deliveries and realized Ancillary Services revenues[95] in accordance with D.18-10-019.[96] Subsequently, the Renewable benchmark will be updated per the Commission-approved formula[97] when adjusting the Brown Power Benchmark.

7. Safety Considerations

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

[94] D.18.10.019 at 141.

[95] Actual 2018 market prices of PCIA-eligible generation deliveries and realized ancillary services shall be determined by the net of CAISO revenues for PCIA-eligible resources.

[96] D.18-10-019, p. 161

[97] Resolution E-4475, Exhibit A

environment, and an increase in the incidences of infectious disease, asthma, and other human health-related problems."[98]

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

8. Change in Determination of Need for Hearing

In Resolution ALJ 176-3416, dated May 10, 2018, the Commission preliminarily categorized this application as ratesetting as defined in Rule 1.3 and anticipated that this proceeding would reasonably require hearings. A PHC was held on July 9, 2018, and a scoping memo and ruling indicating that hearings were necessary was issued. However, the parties thereafter agreed that evidentiary hearings were not necessary. Given that no hearings were held in the current proceeding, we change out preliminary and scoping memo determination regarding hearings to no hearings necessary.

9. Admittance of Testimony and Exhibits into Record

Since evidentiary hearings were not held in A.18-05-003, there was no opportunity to enter prepared testimony and exhibits into the record. In order to fairly assess the record, it is necessary to include all testimony and exhibits served by SCE. In its motion of November 15, 2018, SCE requested, pursuant to Rule 13.8 of the Commission's Rules of Practice and Procedure,[99] that the

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[98] AB 32 § 38501(a).

[99] All future references to "Rule" or "Rules" hereinafter shall refer to the Commission's Rules of Practice and Procedure.

Commission receive the pubic and confidential version of its Exhibits into the record of A.18-05-003. Therefore, we identify the public and confidential version of SCE's supporting testimony as Exhibits SCE-1, SCE-1C, SCE-2, SCE-3, SCE-3C, SCE-4 and SCE-4C.[100] Given the necessity of SCE's testimony to our assessment of the proposals put forth, we admit into evidence the public and confidential versions of SCE's exhibits mentioned above.

10. Motion to Seal and Other Procedural Matters

Pursuant to Rule 11.5, portions of the record of a proceeding (such as served testimony) may be sealed. ARB cap-and-trade regulations prohibit disclosure of auction-related information in most circumstances. ARB's goal is to prevent market collusion. The Commission is interested in ensuring that the public has access to information related to utility rates, but also has its own rules to protect the confidentiality of market sensitive information. D.14-10-033 established Confidentiality Protocols to maximize the amount of information that utilities can make publicly available, while ensuring they do not disclose market sensitive information.

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[100] Exhibit SCE-1 – ERRA 2019 Forecast of Operations (Public Version) dated May 1, 2018.
Exhibit SCE-1C – ERRA 2019 Forecast of Operations (Confidential Version) dated May 1, 2018.
Exhibit SCE-2 – ERRA 2019 of Operations Witness Qualification and Declarations re: Confidentiality dated May 1, 2018.
Exhibit SCE-3 – ERRA 2019 Forecast of Operations (Supplemental Testimony) (Public Version) dated June 1, 2018.
Exhibit SCE-3C – ERRA 2019 Forecast of Operations (Supplemental Testimony) (Confidential Version) dated June 1, 2018.
Exhibit SCE-4 – Updated Testimony ERRA 2019 2019 Forecast of Operations (Public Version) dated November 7, 2018.
Exhibit SCE-4C – Updated Testimony ERRA 2019 2019 Forecast of Operations (Confidential Version) dated November 7, 2018.

SCE submitted public and confidential versions of its testimony. Pursuant to Rule 11.5 and D.06-06-066, SCE filed a motion requesting that the confidential supplemental information be filed under seal.

The information referenced in the motion to file under seal and the information contained in the testimony filed under seal constitute commercially sensitive material and include information that falls under the "ARB Confidential" and "Confidential" categories in the Confidentiality Matrix.

We grant confidential treatment of and seal (as detailed in the ordering paragraphs herein) Exhibits SCE -1C, SCE-3C and SCE-4-C, and the confidential portions in templates and workpapers submitted with SCE's Application on May 1, 2018 and updated on June 1, 2018 and November 7, 2018. The documents placed under seal shall remain under seal for the applicable period of time set forth in the Confidentiality Matrix in D.14-10-033 and General Order (GO) 66-D.[101]

All rulings by the assigned Commissioner and assigned ALJ are affirmed herein; and all motions not specifically addressed herein or previously addressed by the assigned Commissioner or ALJ, are denied.

11. Compliance with the Authority Granted Herein

SCE must submit a Tier 1 advice letter necessary advice letter to the Commission's Energy Division within 30 days of the effective date of this decision in order to implement the rate changes authorized by this decision. The tariff sheets filed in this advice letter shall be effective on or after the date filed

[101] D.17-09-023 adopted GO 66-D.

subject to the Commission's Energy Division determining they are in compliance with this decision.

12. Comments on Proposed Decision

The Alternate Proposed Decision of Commissioner Martha Guzman Aceves in this matter was mailed on January 22, 2019 in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Opening comments were timely filed on February 11, 2019 by [SCE and Clean Power Advocates (CPA)]. Reply comments were filed on [February 19] by [SCE, CPA, Cal Advocates, and CLECA.

This section summarizes the changes made to the alternate proposed decision in response to comments and reply comments. Rather than summarizing every comment made, we focus on major arguments where we did or did not make revisions in response to party input. In response to party input, we modified Section 6.4, Conclusions of Law 9 and Ordering Paragraph 7.

In comments to the APD, SCE states that the APD is inconsistent with statutes prohibiting cost shifts from departing load customers to utility bundled customers, citing California Public Utilities Code (PUC) Sections 366.2, 366.3, and 365.2, and arguing that the brown power true up enables cost shifting to bundled customers.

The Clean Power Alliance supports the APD and disputes SCE's assertion of cost shifting, stating that the brown power true up aligns all 2018 forecast brown power components with 2018 actual values, not just the components that benefit bundled customers. In 2018, higher natural gas prices translated into higher brown power prices, affecting both the costs and the value of SCE's procurement portfolio. The brown power value of SCE's portfolio was also higher than forecast, for the same reasons actual costs were higher, resulting in an overstatement of the PCIA charge for departing load customers. Without the APD's direction to implement the brown power true-up for 2018, forecast brown power costs would be trued up to reflect actual market results, but the forecast brown power value would not. In CPA's view, the APD "brings balance by implicitly recognizing that the undercollection amortization and the brown power true-up are two sides of the same coin. In this way, the APD avoids a direct cost shift from bundled to departing load customers."

We agree with CPA and find that at this time a brown power true up is necessary to establish incrementally more accurate values for brown power, and to in fact avoid shifting higher-than-anticipated costs from SCE's 2018 undercollection costs to departing load customers. Cost shifts have persisted throughout the years, and this is another incremental progress as PCIA methodology continues to evolve, and we believe that this brown power true up makes meaningful improvement to the 2019 ERRA forecast.

SCE also asserts that the PCIA decision established that a brown power true-up occur

prospectively, particularly since PABA accounts put forth in AL 3914-E were not in place in 2018 and have not been approved by the Commission. The CPA comments support the APD in its intent to include the true up in the 2019 PCIA.

We disagree with SCE that the true up was intended to be prospective and that it cannot be performed in the absence of the PABA. The PCIA Decision establishes that brown power true up is possible for subject year 2018, a position also supported by CCAs. While the PABA was not established for the subject year 2018, reliance on any utility-reported values outside of the PABA, such as reconstructed transactions for the year, seems more likely to lead to less transparency. Therefore, in the absence of a PABA with utility-recorded subaccounts for each vintaged portfolio to account for billed revenues, generation resource costs, and net California Independent System Operator market revenues associated with energy and ancillary services, we find it reasonable to maintain the transparent and acknowledged interim method to calculate these costs based on actual CAISO market revenues. When its PABA account is established, the Commission authorizes SCE to use PABA- recorded costs for the true up values.

In its opening comments, SCE states that there is also no record evidence supporting a 2018 brown power true-up, and that during the PCIA proceeding no party other than SCE submitted testimony, parties waived evidentiary hearings, and that no evidence was submitted regarding what a brown power true-up would entail for SCE's bundled service customers. However, the SoCal CCAs, in their response to SCE's November 7 Update Testimony, estimated the value of the brown power true-up and described the calculation using a proxy value for the actual 2018 brown power price. The proposed methodology aligns with the APD's adopted methodology. There is no record of SCE's response to the Joint CCAs, and in fact only responded to the issue when proposed by the APD.

SCE expresses concern that vulnerable bundled service customers in disadvantaged communities in places like the Central Valley, as well as all CARE and Medical Baseline bundled service customers will experience high rates associated with the undercollection. The Commission shares that concern and realizes that there are vulnerable customers in CCAs that are equally disaffected by SCE's high undercollection. The purpose of the brown power true up is not to play favorites; rather, it is an incremental step towards improving accuracy and transparency.

The APD sought to provide a straightforward directive for SCE's calculation of the brown power true-up, ordering SCE to follow a methodology reflective of the only discussion of a proposed methodology presented on the record and comports with D.18-10-019. However, SCE points out that the APD wording directed the true up to replace the forecasted 2018 brown power benchmark in the 2018 Forecast ERRA case with the actual load weighted average price of brown power to reflect 2018 actual market prices and to calculate the total indifference amount. We appreciate the opportunity to provide greater clarity here, so we have revised the APD to direct SCE to calculate the true-up by applying actual 2018 market prices to actual PCIA-eligible generation deliveries and realized Ancillary Services revenues in accordance with D.18-10-019. Subsequently, the Renewable benchmark will be updated per Resolution E-4475 when adjusting the Brown Power Benchmark.

SCE states that a complete true up would demonstrate that cumulatively costs were shifted to bundled customers in 2018, not to departing load customers. This type of situation may in fact arise in a following year after the RA and REC components of the PCIA benchmark are subject to true-up. At this time, we remain focused on the PCIA decision to enable only the brown power true up.

13. Assignment of Proceeding

Martha Guzman Aceves is the assigned Commissioner and Zita Kline is the assigned ALJ in this proceeding.

Findings of Fact

1. SCE's 2019 forecast ERRA revenue requirement is $4,043.098 million (which excludes costs associated with the ERRA Balancing Account).

2. SCE's 2019 forecast Fuel and Purchased Power Revenue Requirement is $4,195.681 million.

3. SCE's request in the November Update was based, in part, on the assumption that the Commission would approve its pending application for termination of two geothermal PPAs owned by Coso in A.18-03-010.

4. SCE's June testimony reflected the contract costs and market generation revenues for the two Coso geothermal PPAs but not the termination payment.

5. SCE's November Update reflected a termination payment of $100 million in 2019, but not the contract costs and market generation revenues of the two Coso geothermal PPAs.

6. On November 29, 2018, the Commission approved SCE's Application for authorization to execute the Coso termination agreement.

7. D.18-11-036 approves SCE's proposal to include the costs of the Coso Termination Agreement in the Total Portfolio Costs used to set the 2019, 2020 and 21021 CTC and PCIA.

8. SCE's forecast for the GTSR is 10,296,441 KWh of participation through the green tariff option and 699,593 KWh of participation through the enhanced community renewables option.

9. SCE's forecast overcollection of $73.503 million in the NSGBA will offset a portion of SCE's revenue requirement in 2019 forecast rates.

10. SCE's forecast overcollection of $28.221 million in the ESMA will offset a portion of SCE's revenue requirement in 2019 forecast rates.

11. SCE's GHG allowance refund of $349.898 million consist of 1) a refund of $390.680 million in net 2019 GHG auction proceeds, 2) a cost of $202,000 in

outreach and administrative expenses and 3) a cost of $40.579 million in Clean Energy and EE programs.[102]

12. The 2019 forecast DAC-SASH funding to be set aside is $4.600 million.

13. The 2019 forecast SOMAH funding to be set aside is $40.854 million.

14. The 2019 forecast DAC-GT and CSGT program funding to be set aside is $2 million in total for both programs.

15. SCE's 2019 forecast EITE customer return is $25.885 million.

16. SCE's 2019 forecast Small Business Volumetric Return is $19.573 million.

17. The 2019 forecast semi-annual residential Climate Credit is $33 per household.

18. SCE's 2019 GHG costs are $299.039 million, including FF&U.

19. In Resolution ALJ 176-3416, dated May 10, 2018, the Commission preliminarily categorized this proceeding as ratesetting, and preliminarily determined that hearings were necessary. In the scoping memo, the assigned Commissioner stated that evidentiary hearings would be held if necessary. No hearings were held.

20. Challenges to facts supporting SCE's proposed 2019 forecast of fuel and purchased power prices; natural gas prices, electricity prices; GHG and proceeds; demand response costs; bundled customer electric sales and year-end balancing accounts (with the exception of the ERRA Balancing Account) are waived by parties in this proceeding by virtue of stipulation to waive evidentiary hearing.

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[102] *See* Assembly Bill 32; D.12-12-033; D.13-12-041; D.14-10-033, as corrected by D.14-10-055 and D.15-01-024.

21. D.18-10-019 requires that revenue allocation factors for vintage Indifference Amounts "be consistent with the factors used to allocate generation costs to their bundled service customers."

22. SCE may elect to assign a zero value to excess capacity expected to remain unsold in this 2019 ERRA forecast proceeding.

23. SCE's revenue requirement adjustment for the 2017 Tax Reform Act will be determined through a pending decision in A.16-09-001.

24. It is premature to assign a revenue requirement due to the 2017 Tax Reform Act in the 2019 ERRA forecast proceeding.

25. Any 2017 Tax Reform Act-related discrepancies between the forecast and actual value of SCE's PCIA will be trued-up in SCE's 2019 ERRA Compliance proceeding.

26. It is reasonable that the subject year of the brown power true up required by Ordering Paragraph of D.18.10.019 commences with 2018.

27. SCE requested the admittance of its exhibits into evidence pursuant to Rule 13.8.

28. GO 66-D and D.10-14-033 provide definitions and guidance regarding public and confidential records provided to and requested from the Commission.

29. By D.06-06-066, the Commission implemented SB 1488, which required that the Commission examine its practices regarding confidential information, as it applies to the confidentiality of electric procurement data (what may be market sensitive) submitted to the Commission.

30. SCE requests that certain selected exhibits be given confidential treatment pursuant to GO 66-D and D.06-06-066.

31. SCE requests that the confidential testimony and certain exhibits included with its 2019 Forecast Application, June Update and November Update, be filed under seal pursuant to Rule 11.4.

32. We have granted similar requests for confidential treatment in the past.

Conclusions of Law

1. The Commission should find reasonable and adopt SCE's updated 2019 ERRA forecast revenue requirement of $4,043.098 million.

2. SCE's forecast of fuel and purchased power prices; natural gas prices; electricity prices; GHG costs and proceeds; demand response costs; bundled customer electric sales and year-end balancing account balances (with the exception of the ERRA Balancing Account) are reasonable.

3. SCE's forecast of fuel and purchased power prices; natural gas prices; electricity prices; GHG costs and proceeds; demand response costs; bundled customer electric sales and all year-end balancing account balances (with the exception of the ERRA Balancing Account) are in compliance with applicable Commission decisions and requirements.

4. SCE should collect the costs for termination payments under the Coso Power Purchase Agreements made in 2019 in the 2019 ERRA Forecast.

5. SCE's assignment of a zero value to excess capacity expected to remain unsold in each forecast month is consistent with the Commission's adopted PCIA methodology in D.18-10-019.

6. SCE's calculation of the PCIA without accounting for the 2017 Tax Reform Act is reasonable in SCE's 2019 ERRA forecast.

7. It is reasonable to true-up the difference between the forecast value of excess RA capacity expected to remain unsold and the actual value of any excess

capacity expected to remain unsold, but which was sold for some value, in SCE's 2019 ERRA Compliance proceeding.

8. SCE's revenue allocation methodology as set forth in the updated PCIA worksheet, with the use of cumulative billing determinants, is reasonable.

9. A true-up of brown power in the 2019 ERRA Forecast based on 2018 actual net CAISO revenues for PCIA-eligible resources complies with D.18-10-019.

10. SCE's request, that the public and confidential versions of its testimony and exhibits included with its application be received into evidence, should be granted.

11. SCE's request for confidential treatment of unredacted versions of SCE's Testimony and Exhibits included with its Application and November Update should be granted pursuant to Rule 11.5, GO 66-D and D.14-10-033.

12. SCE should be authorized to modify its tariffs to reflect its forecast 2018 ERRA and GHG allowance revenues as specified in this decision.

13. SCE is authorized to set aside $2 million in GHG allowance revenue in 2019 for the DAC-GT and CSGT programs.

14. Recovery of the ERRA Balancing Account undercollection of $743.429 million should be considered as part of SCE's Trigger Application (A.18-11-009).

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

O R D E R

IT IS ORDERED that:

1. Southern California Edison Company is authorized to recover a total 2019 Energy Resource Recovery Account electric procurement cost revenue

requirement forecast of $4,043.098 million, consisting of a revenue requirement of 1) $4,195.681 million for fuel and purchased power, 2) forecast refunds of $28.221 million for the Energy Settlements Memorandum Account and 3) forecast refunds of $73.503 million for the New System Generation Balancing Account, 4) a forecast revenue requirement of $299.039 million in Greenhouse Gas (GHG) Cap-and-Trade costs and 5) a refund of $349.898 million in GHG allowance auction proceeds.[103]

2. Costs incurred by Southern California Edison Company for termination payments made in 2019 under the Coso termination agreement shall be recovered in the 2019 Energy Resources Recovery Account Forecast.

3. Southern California Edison Company's request for recovery of $743.429 million in the Energy Resources Recovery Account Balancing Account in 2019 rates shall be reviewed in Application 18-11-009.

4. Southern California Edison Company's rate component for the Green Tariff Shared Renewables Program is approved.

5. Southern California Edison Company (SCE) must return $349.898 million in net Greenhouse Gas proceeds to SCE's customers.

6. Southern California Edison Company shall calculate the Power Charge Indifference Adjustment by allocating the cumulative vintaged Indifference Amount to each rate group using the allocation factors followed by dividing the forecasted system sales for the forecast year.

7. The 2019 forecast shall include a true-up of the 2018 forecast year for brown power. The true-up shall be include a calculation of the indifference

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[103] *See* Assembly Bill 32; D.12-12-033; D.13-12-041; D.14-10-033, as corrected by D.14-10-055 and D.15-01-024.

amount using the adopted PCIA workpapers in the 2018 Forecast ERRA case. Southern California Edison Company is ordered to calculate the true-up by applying actual 2018 market prices to actual PCIA-eligible generation deliveries and realized Ancillary Services revenues in accordance with D.18-10-019. Subsequently, the Renewable benchmark will be updated per Resolution E-4475 when adjusting the Brown Power Benchmark, the difference between the total indifference amount adopted in the 2018 Forecast ERRA case and that calculated with the 2018 brown power true-up shall be reflected in rates in a manner complaint with the PCIA workpapers filed in this proceeding.

8. Southern California Edison Company's (SCE) request to treat as confidential exhibits SCE-1C, SCE-3C and SCE-4C, as well as pertinent testimony thereunder, is granted for a period of three years from the date of this order. During this three-year period, this information shall not be publicly disclosed except on further Commission order or Administrative Law Judge ruling. If SCE believes that it is necessary for this information to remain under seal for longer than three years, it may file a new motion showing good cause for extending this order by no later than 30 days before the expiration of this order.

9. Southern California Edison Company shall file a Tier 2 Advice Letter (AL) and revised tariff sheets within 15 days of the issuance of this decision to implement the rate changes authorized by this decision. The AL shall include changed tariff sheets and supporting documentation for:

a. Residential rate schedules (including master-metered rate schedules) to include the authorized 2019 Climate Credit amount;

b. Small business rate schedules to include the volumetric dollars per kilowatt hour greenhouse gas rate offset for small business customers; and

c. The amount approved in Ordering Paragraph 1.

10. The determination made in the Assigned Commissioner's Scoping Memo and Ruling that hearings were necessary is changed to no hearings necessary.

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

12. Application 18-05-003 is closed.

This order is effective today.

Dated February 21 2019, at San Francisco, California.

LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
GENEVIEVE SHIROMA
Commissioners

I dissent.

/s/ MICHAEL PICKER
Commissioner

I reserve the right to file a concurrence.

/s/ MARTHA GUZMAN ACEVES
Commissioner

CONCURRENCE OF COMMISSIONER GUZMAN ACEVES ON ITEMS 33A AND 34A ON THE COMMISSION VOTING MEETING AGENDA OF FEBRUARY 21, 2019 DECISIONS REGARDING PACIFIC GAS AND ELECTRIC CO. AND SOUTHERN CALIFORNIA EDISON CO. 2019 ENERGY RESOURCE RECOVERY ACCOUNT FORECASTS

Decisions (D.) 19-02-023 and D.19-02-024, issued March 4, 2019, are two alternate decisions to improve the accuracy of both PG&E and SCE's 2019 forecast electric procurement revenue requirement, in particular the brown power true-up from 2018. The ERRA alternate decision appropriately addresses unforecasted revenues from brown power in 2018, just as companion decisions address undercollection of costs, such as the SCE trigger application for 2018, Application 18-11-009.

The ERRA forecasts are the process we use to allow utilities to collect revenue in anticipation of the costs of procuring energy for the year ahead, as well as other major expenditures, including the GHG auction proceeds and cap and trade costs, Energy Settlements Memorandum Accounts and the New System Generation Balancing Account. We approve these forecasts and then consolidate them in the annual electric true-up. The 2019 forecasts are $2.9 billion for PG&E and more than $4 billion for SCE.

Both the State Legislature and the Commission have established forecast triggers for addressing revenue shortfalls (or 'undercollections'). The triggers provide mechanism for the utilities to notice when the actual market prices diverge from the forecasts by 5%. The intent of the trigger notification mechanism is to shed some daylight on where the energy market is going—particularly if the market does not appear to self-correct—and enable us to "true-up" the rates midstream in order to minimize bill shocks.

We approved such a trigger application in January for SCE, whose undercollection was more than $800 million. Originally, SCE sought to roll this into its 2019 forecast; however, due to the magnitude of the undercollection we decided to treat it as a separate application. Nevertheless, this illustrates that various true-ups are perpetual functions within the ERRA proceedings.

Interestingly, while on one hand we are diligent in addressing the cost side of the equation--ensuring that the utilities are able to recover undercollections--we have so far been under-emphasizing the unforecasted revenue side of the equation by some of the procured electricity. The growth and transition in Load Serving Entities necessitates greater accuracy in both the costs and revenues generated by the utilities procured electricity.

The Power Cost Indifference Account (PCIA) is an important part of ratemaking that came out of the energy crisis to ensure that departing load or unbundled customers pay for investments made by the utilities to serve their load. The statutory framework supporting CCA formation requires the Commission to ensure that departing customers remain responsible for certain costs incurred on their behalf by their utility, without being subject to costs that were not incurred on their behalf, and to do the accounting as accurately as possible. In the most recent PCIA decision D.18-10-019 Ordering Paragraph 7, the Commission ordered the utilities to annually true-up their PCIA rates to reflect actual values realized in market transactions for the subject year for the Brown Power Index to capture the full costs and revenues of generated by brown power, including market energy prices and ancillary services revenues. Historically, this component of the PCIA is based entirely on forecasts, using Brown Power Benchmark prices with no adjustment or true-up to reflect actual energy costs incurred by those customers. In 2018 we saw startling variations between the forecast prices of electricity and other components of the so-called brown power and actual market prices. Therefore, we are following the Decision language and implementing a true-up.

One concerning topic of the utilities' comments to the Alternate Proposed Decision (APD) was that of cost shifting, and their assertion that a brown power true-up in the absence of the RPS and RA adjustments would impermissibly shift cost burdens to bundled customers. However, at this time we have Decision language explicitly directing a brown power true-up using a transparent methodology; the methodology to calculate and true-up other PCIA cost components will take place this year in

Phase 2 of the PCIA proceeding, as described in President Picker's recent Scoping Memo.

Other parties also expressed concern that there was insufficient evidentiary record to order the brown power true-up, yet I believe the APD covers the concern over the evidentiary record for requiring the brown-power true-up. In addition to the Ordering Paragraph 7 already discussed, brown power calculation has been considered a straightforward exercise, and although we do not have utility-recorded transactions for 2018, we have equally transparent and accessible market data from the CAISO that can be relied upon for subject year 2018.

By the end of this year, California will see more than half of its investor-owned utility customers served by CCAs: 41% of PG&E's load, and 15% of SCE's load. We face many challenges during this transition, and transparency in forecasting is critical step forward to ensuring a more balanced transition.

Dated March 4, 2019 at San Francisco, California.

/s/ MARTHA GUZMAN ACEVES

Martha Guzman Aceves
Commissioner