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SAN FRANCISCO, CA 94102-3298

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TO PARTIES OF RECORD IN RULEMAKING 24-01-017:

This is the proposed decision of Administrative Law Judge Nilgun Atamturk and Administrative Law Judge Darryl Gruen.

Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's December 17, 2026, Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

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

/s/ MICHELLE COOKE
Michelle Cooke
Chief Administrative Law Judge

MLC: vhj
Attachment

Decision **PROPOSED DECISION OF ALJ ATAMTURK (Mailed 11/13/2026)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration, and Consider Further Development, of California Renewables Portfolio Standard Program.	Rulemaking 24-01-017

DECISION ON 2026 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

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DECISION ON 2026 RENEWABLES PORTFOLIO STANDARD PROCUREMENT PLANS

Summary

Today's decision adopts, with modifications, the Draft 2026 Renewables Portfolio Standard (RPS) Procurement Plans of the following retail sellers:

1. The large Investor-Owned Utilities (IOUs) the California Public Utilities Commission (Commission) regulates: Pacific Gas and Electric Company (PG&E); Southern California Edison Company (SCE); and San Diego Gas & Electric Company (SDG&E).
2. The Small and Multi-Jurisdictional Utilities (SMJUs) under the Commission's jurisdiction: Bear Valley Electric Service, Inc. (BVES); Liberty Utilities (CalPeco Electric), LLC (Liberty); and PacifiCorp d/b/a Pacific Power (PacifiCorp).
3. Community Choice Aggregators (CCAs): Apple Valley Choice Energy; Ava Community Energy; Central Coast Community Energy; City of Palmdale; City of Pomona; City of Santa Barbara; City of San Jacinto dba San Jacinto Power; Clean Energy Alliance (CEA); Clean Power Alliance of Southern California; CleanPowerSF; Desert Community Energy; King City Community Power; Lancaster Choice Energy; Marin Clean Energy; Orange County Power Authority; Pico Rivera Innovative Municipal Energy; Pioneer Community Energy; Rancho Mirage Energy Authority; Redwood Coast Energy Authority; San Diego Community Power; San Jose Clean Energy; Silicon Valley Clean Energy; Sonoma Clean Power Authority; Valley Clean Energy Alliance, and Westlight Energy (d/b/a Peninsula Clean Energy Authority).
4. Electric Service Providers (ESPs): 3 Phases Renewables, Inc.; BP Energy Retail Company California LLC; Calpine Energy Solutions, LLC; Calpine Power America-CA, LLC; Commercial Energy of Montana, Inc.; Constellation NewEnergy, Inc.; Direct Energy Business, LLC; Pilot Power Group, LLC; Shell Energy North America (US), L.P.; The

Regents of the University of California; and Volt Energy, LLC.

Any Draft 2026 RPS Plan that does not require a correction or clarification is deemed final. For the Draft 2026 RPS Plans that require corrections as identified in this decision, the Final 2026 RPS Plans are due no later than 30 days following the issuance of this decision by the Commission. This decision adopts the following directives:

Large Investor-Owned Utilities:

1. The IOUs' requests to procure long-term RPS-eligible resources are approved. Any Tier 3 Advice Letter submitted by the IOUs must clearly demonstrate that the contracts procured under this procurement authority are RPS-eligible and meet either RPS needs, portfolio goals from their Integrated Resource Planning (IRP) filings, or a formally adopted IRP portfolio, or any remaining IRP procurement needs for orders issued through the RPS Plan implementation year.
2. The IOUs are authorized to conduct short-term transactions to procure RPS resources by submitting contracts and receiving approval through the Tier 1 Advice Letter process, until a decision considering inclusion of short-term RPS transactions in the Integrated Resource Planning rulemaking's bundled procurement plans is issued. The IOUs must demonstrate that the contracts are RPS-eligible and that they are either required to meet RPS needs or that the contracts are necessary for the IOUs to comply with IRP-related orders.
3. PG&E, SCE, and SDG&E are authorized to discontinue providing the informational time-of-delivery heatmaps in their RPS Plans.
4. SCE and SDG&E are authorized to discontinue reporting on Green Tariff Shared Renewables (GTSR) programs in their RPS Plans. PG&E must continue reporting on its

GTSR program until it ceases using a borrowed pool of RPS resources for its GTSR needs.

5. PG&E is authorized to renegotiate its existing contracts.
6. PG&E's request to transact RPS resources via bilaterals is approved.
7. PG&E's request to participate in third-party competitive solicitations is approved.
8. PG&E's request to transact RPS eligible products via brokers and exchanges is approved.
9. PG&E is authorized to retire renewable energy credits (RECs) for Low Carbon Fuel Standard (LCFS) Credits.
10. PG&E's request for authority to sell short-term RPS products from its retained bundled share of its voluntary allocation at a price indexed to the applicable final PCC 1 Market Price Benchmark (MPB) is approved.
11. SCE is authorized to purchase and sell portfolio content category (PCC) 1, PCC 2, and PCC 3 RECs.
12. SCE is authorized to use solicitations, other market participants' solicitations, bilateral contracts, brokers, and exchanges to procure RECs.
13. SCE's procurement protocols for new and existing resources, REC transaction protocols, and least-cost best-fit evaluation methodology are approved.
14. SCE's request for approval of revised pro forma agreements is granted.
15. SCE is authorized to retire RECs for LCFS Credits.
16. SDG&E is authorized to use banked RECs consistent with excess procurement rules to meet RPS requirements, subject to the condition that it exhaust RECs banked after 2018 before using pre-2019 banked RECs.
17. SDG&E is authorized to conduct optional bundled renewable energy plus RECs and/or unbundled REC purchases from new or existing resources, either through short-term or long-term contracts, to the extent the

procurement is either needed to meet RPS requirements or to comply with the Commission's procurement related orders issued in the IRP proceeding.

18. SDG&E's request to procure RECs for compliance through solicitations, bilateral agreements, or brokers and exchanges is approved.
19. SDG&E's request for authorization to sell RPS eligible products is approved.
20. SDG&E's request to buy and sell RECs in the same year is approved.
21. SDG&E should address the deficiencies listed in Section 6.3.6 of this decision in its Final 2026 RPS Plan.
22. The procuring IOUs must continue to submit either Tier 1 or Tier 3 Advice Letters seeking approval of the short-term or long-term procurement contracts, respectively.
23. The IOUs that sell RPS products must continue to submit Tier 1 Advice Letters seeking approval of the short-term sales contracts.

Small and Multi-Jurisdictional Utilities:

24. The Draft 2026 RPS Plans of BVES, Liberty, and PacifiCorp are accepted as final with no required modifications.

Community Choice Aggregators and Energy Service Providers:

25. Several CCAs and ESPs must supplement their Final 2026 RPS Plans according to the directives provided in Section 8 of this decision and its subsections.

This proceeding remains open.

1. Background

This section provides an overview of the California Renewables Portfolio Standard (RPS) program and the procedural background for the 2026 RPS planning cycle.

1.1. RPS Program Overview

The RPS program was established by Chapter 516, Statutes of 2002 (Senate Bill (SB) 1078), and has since been modified several times by Chapter 464, Statutes of 2006 (SB 107); Chapter 685, Statutes of 2007 (SB 1036); Chapter 1, Statutes of 2011 (SB X1-2); Chapter 600, Statutes of 2011 (SB 836); Chapter 547, Statutes of 2015 (SB 350); and Chapter 312, Statutes of 2018 (SB 100). The RPS program is codified in Public Utilities (Pub. Util.) Code Sections 399.11-399.33.[1]

SB 1078 established the RPS program, requiring that 20 percent of retail electricity sales come from renewable resources by 2017. SB 107 later accelerated this requirement, moving the 20 percent target to 2010. SB 1036 changed the RPS contract payment structure, while SB 836 required the California Public Utilities Commission (Commission) to report renewable energy contract costs to the Legislature.

SB X1-2 expanded the program by requiring all retail electricity sellers and publicly-owned utilities to procure at least 33 percent of electricity delivered to their retail customers from renewable resources by 2020. SB 350 added interim annual RPS targets with three-year compliance periods. It also required 65 percent of RPS procurement to come from long-term contracts lasting 10 years or more.

In 2018, SB 100 raised the target again to 60 percent by 2030 and set a broader goal for 100 percent of the state's retail electricity sales to come from renewable and zero-carbon resources by 2045. SB 1020 (Chapter 361, Statutes of 2022) later established interim targets for eligible renewable energy resources and zero-carbon resources to supply 90 percent of all retail sales of electricity to

[1] All references are to the Public Utilities Code, unless otherwise noted.

California end-use customers by December 31, 2035, and 95 percent of all retail sales of electricity to California end-use customers by December 31, 2040.

As part of implementing SB X1-2, the Commission refined the RPS procurement process in Decision (D.) 12-11-016. In earlier decisions, the Commission had set forth the process for filing and evaluating the RPS Procurement Plans (RPS Plans) of electrical corporations and other retail sellers. Under the statute, the term "retail seller" includes small and large electrical corporations, CCAs, and Electric Service Providers (ESPs).[2]

1.2. Procedural Background

On March 27, 2026, an assigned Commissioner and assigned Administrative Law Judge (ALJ) Ruling (2026 ACR) was issued according to the authority provided in Pub. Util. Code Section 399.13(a)(1). This 2026 Assigned Commissioner's Ruling (ACR) identified the 2026 RPS Procurement Plan filing requirements for all retail sellers of electricity and set a schedule for the Commission's review of the 2026 RPS Plans.

The following retail sellers timely filed their Draft 2026 RPS Plans: Pacific Gas and Electric Company (PG&E); Southern California Edison Company (SCE); San Diego Gas & Electric Company (SDG&E); Bear Valley Electric Service (BVES); Liberty Utilities (CalPeco Electric), LLC (Liberty); PacifiCorp d/b/a Pacific Power (PacifiCorp); Apple Valley Choice Energy; Ava Community Energy; Central Coast Community Energy; City of Palmdale; City of Pomona; City of Santa Barbara; Clean Energy Alliance; Clean Power Alliance of Southern

[2] Pursuant to Pub. Util. Code Section 399.12(j) retail seller means an entity engaged in the retail sale of electricity to end-use customers located within the state, including an electrical corporation, as defined in Section 218, a community choice aggregator, and an electric service provider, as defined in Section 218.3.

California (Clean Power Alliance or CPA); CleanPowerSF;[3] Desert Community Energy; King City Community Power; Lancaster Choice Energy; Marin Clean Energy; Orange County Power Authority; Pico Rivera Innovative Municipal Energy (Pico Rivera); Pioneer Community Energy; Rancho Mirage Energy Authority; Redwood Coast Energy Authority; San Diego Community Power (SDCP); San Jacinto Power; San Jose Clean Energy; Silicon Valley Clean Energy; Sonoma Clean Power Authority; Valley Clean Energy Alliance; Westlight Energy (d/b/a Peninsula Clean Energy); 3 Phases Renewables, Inc.; BP Energy Retail Company California LLC (BP Energy); Calpine Energy Solutions, LLC; Calpine Power America-CA, LLC; Commercial Energy of Montana, Inc. (Commercial Energy); Constellation NewEnergy, Inc.; Direct Energy Business, LLC; Pilot Power Group, LLC (Pilot Power); Shell Energy North America (US), L.P. (Shell Energy); The Regents of the University of California, and Volt Energy, LLC.

Comments on the Draft 2026 RPS Plans were filed on July 13, 2026, by the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) and Ava Community Energy. Reply comments were filed on July 27, 2026, by PG&E and SDG&E.

On July 27, 2026, SCE filed a motion to update its Draft 2026 RPS Plan.

1.3. Submission Date

This matter was submitted on July 27, 2026, upon receipt of reply comments on the Draft 2026 RPS Plans and SCE's updated Draft 2026 RPS Plan.

[3] Good cause having been shown, CleanPowerSF's motion to consider its Draft 2026 Renewable Portfolio Standard Procurement Plan timely filed, dated June 15, 2026, is hereby granted.

2. Issues Before the Commission

In this decision, we review the Draft 2026 RPS Plans for information required by statute and the 2026 ACR and dispose of any requests or proposals specific to each retail seller.

To help retail sellers organize the submission of comprehensive 2026 RPS Plans, the 2026 ACR listed specific issues to address and guidance on managing the information, including quantitative analysis and narratives supporting the retail seller's assessment of its portfolio's future procurement decisions.

The issues required by statute and the 2026 ACR are as follows:[4]

1. Summary of Major Changes to RPS Plan;
2. Executive Summary Key Issues;
3. Compliance with Recent Legislation and Impact of Regulatory Changes;
4. Assessment of RPS Portfolio Supplies and Demand;
5. Project Development Status Update (PDSU);
6. Potential Compliance Delays;
7. Risk Assessment;
8. Renewable Net Short (RNS) Calculations;
9. Minimum Margin of Procurement (MMoP);
10. Bid Solicitation Protocol;
11. Safety Considerations;
12. Consideration of Price Adjustment Mechanisms;
13. Cost Quantification; and
14. Impact of Transmission and Interconnection Delays.

[4] S*ee* 2026 ACR, Table 1 Summary of Requirements for 2026 RPS Plans, for the complete list of 2026 RPS Plan requirements.

We reviewed the Draft 2026 RPS Plans for completeness, accuracy, and compliance. Based on the guidance in the 2026 ACR, we also examined the Draft 2026 RPS Plans for the following:

1. Compliance with Table 1 of the 2026 ACR, which required all RPS Plans to be accompanied by an officer-verified checklist.
2. Description of the retail seller's overall plan for procuring RPS resources to satisfy the RPS program requirements while minimizing cost and maximizing value to customers, as well as demonstrating how retail sellers comply with direction for RPS planning in SB 350, SB 100, and SB 901 (Dodd, Stats. 2018, ch. 626). This includes, but is not limited to, any plans for building retail seller-owned resources, investing in third-party owned renewable resources, and engaging in the sales of RPS-eligible resources.
3. Consistency of information in the RPS Plan.
4. Thoroughly describing and addressing procurement and sales of RPS-eligible resources to demonstrate reliability and alignment with the State's policy goals. The 2026 ACR required responses that provide summaries and detailed descriptions necessary to understand how a retail seller's planning and procurement strategies address state goals and satisfy statutory requirements.
5. Compliance with the format and numbering convention directed in Table 1 of the 2026 ACR.

3. Organization of the Decision

The RPS statute requires that retail sellers prepare an annual RPS procurement plan for Commission review.[5] This decision reviews 42 Draft 2026 RPS Plans filed by the IOUs (3), SMJUs (3), ESPs (11), and CCAs (25). The Commission has reviewed and approved or accepted annual RPS procurement

[5] Pub. Util. Code § 399.13(a).

plans for over a decade. Besides reviewing the need for procurement and sale of RPS-eligible resources to balance their portfolios, reviewing the three large IOUs' procurement plans has become routine. This decision describes only the sections of the IOUs', ESPs', and CCAs' procurement plans that are key, disputed, seeking specific requests, or contain deficiencies.

4. Assessment of RPS Long Term Procurement Requirement

SB 350 expanded the RPS long-term contracting requirement by mandating that at least 65 percent of all procurement used for RPS compliance be secured through contracts with terms of 10 years or longer. The 65 percent long-term requirement became effective for all retail sellers in the 2021-2024 compliance period (CP 4), though some elected to comply early, in the 2017-2020 compliance period (CP 3). Prudent long-term contracting assessments should be used to inform a retail seller's RPS procurement planning and procurement decisions for current and future compliance periods.

Our current assessment of the retail sellers' compliance with the 65 percent long-term procurement requirement shows that all but one retail seller is forecasted to meet the requirement for the 2025-2027 compliance period (CP 5).[6] This represents an improvement from last year, when the assessment showed that all but two were forecasted to meet the requirement.[7]

The Commission continues to encourage early planning on long-term procurement to hedge for delays in project development for new renewable build and potential project performance issues. Inadequate long-term

[6] This assessment is based on the retail sellers' most recent annual RPS compliance reports, submitted during July-August, 2026 period, approximately one month after the Draft 2026 RPS Plans were filed.

[7] D.25-12-025 at 11.

procurement planning can impact the risk profile of a retail seller's portfolio and impede the State's progress towards meeting RPS goals.

5. Summary of Party Comments on Draft 2026 RPS Plans

Cal Advocates filed comments on PG&E's and SDG&E's proposed revisions to their REC transaction strategies, and Ava Community Energy filed comments requesting granular forecasting data from PG&E to ensure certainty in Voluntary Allocation and Market Offer (VAMO) deliveries.

The Commission carefully reviewed these comments and concluded that no changes to the draft plans are warranted. PG&E should continue collaborating with its counterparties to remedy concerns about fluctuations in VAMO deliveries.

5.1. Cal Advocates Comments on PG&E's and SDG&E's Draft 2026 RPS Plans

Cal Advocates filed comments on PG&E's and SDG&E's Draft 2026 RPS Plans and recommended that the Commission deny PG&E's and SDG&E's requests regarding the proposed changes to their REC transaction strategies, arguing that "their proposals unnecessarily jeopardize the value that REC sales provide to ratepayers."[8] Cal Advocates argues that PG&E and SDG&E fail to identify ratepayer harms or RPS compliance concerns, demonstrate benefits to ratepayers, or justify eroding safeguards that protect ratepayers from adverse impacts.[9]

In its reply comments, PG&E requests that the Commission approve revisions to its confidential procurement strategies to provide flexibility in

[8] Cal Advocates Comments at 3.

[9] Cal Advocates Comments at 3-4.

pursuing transactions that support affordability for bundled service customers.[10] PG&E argues that the Commission should approve the proposed revisions to its confidential short-term RPS transaction strategies because they support bundled service customer affordability and enable PG&E to meet its RPS compliance obligations at the lowest cost.[11] PG&E states that its RPS planning and compliance obligations are based on its retail sales and therefore directed to serving its bundled service customers. Hence its proposed strategy revisions should be evaluated through the lens of whether they support PG&E's ability to manage RPS obligations for its bundled service customers.[12]

PG&E explains that the proposed revisions are necessary because of significant regulatory uncertainty concerning the costs bundled customers may face for RPS compliance instruments.[13] Following the implementation of the VAMO program, PG&E has relied on its RPS Bank for near-term compliance as an affordability strategy. However, as PG&E asserted, potential new changes associated with the use of pre-2019 banked RECs could make reliance on the RPS bank less cost-effective than incremental procurement.[14] As an example, lower cost PCC 2 or PCC 3 REC products[15] may provide a lower cost procurement

[10] PG&E Reply Comments at 1.

[11] PG&E Reply Comments at 2.

[12] PG&E Reply Comments at 2 and 3.

[13] PG&E Reply Comments at 3.

[14] PG&E Reply Comments at 3.

[15] PCC 1 RECs are renewable energy and RECs, "bundled" together, from facilities with a first point of interconnection within a California Balancing Authority (CBA), or facilities that schedule electricity into a CBA on an hourly or sub-hourly basis. PCC 2 RECs are renewable energy and RECs with incremental electricity, and/or substitute energy, from outside a CBA. Generally, PCC 2 RECs are generated from out-of-state renewable facilities and require a Substitute Energy Agreement that details the simultaneous purchase of energy and RECs from

Footnote continued on next page.

solution for RPS compliance than the use of banked RECs if they are subject to a higher cost RPS MPB.[16] PG&E therefore seeks flexibility to pursue short and long-term RPS transactions based on bundled service customer affordability goals and compliance needs. PG&E maintains that these modifications do not erode ratepayer safeguards or unnecessarily jeopardize the value of REC sales. Rather, PG&E argues, they are intended to lower bundled customer compliance costs, pursue economically beneficial RPS transactions, and provide value to customers.[17]

SDG&E also disagrees with Cal Advocates' comments and notes that Cal Advocates challenges only a small part of SDG&E's Plan, the removal of a REC pricing formula for transactions.[18] SDG&E argues that the formula is unnecessary because the plan retains the regulatory guardrails of the prior approved Plan. SDG&E notes that its REC sales will continue to be evaluated using objective benchmarks or then current market data, quantitative or qualitative criteria, and Commission oversight.[19] A sale may be pursued only when the analysis indicates that it would provide the greatest value to customers and the Commission will determine the reasonableness of the transactions.

SDG&E also argues that a fixed price floor or ceiling can quickly become outdated because of rapid market price fluctuations between solicitation launch and a shortlisting offer.[20] The proposed framework instead allows SDG&E and

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a RPS eligible facility. PCC 3 RECs are "unbundled" and do not include the physical delivery of the energy that generated the REC.

[16] PG&E Reply Comments at 4 and 5.

[17] PG&E Reply Comments at 8.

[18] SDG&E Reply Comments at 1.

[19] SDG&E Reply Comments at 1 and 2.

[20] SDG&E Reply Comments at 2.

the Commission to evaluate REC purchase offers based on prevailing market conditions. According to SDG&E, this approach preserves ratepayer protections while potentially capturing more revenue for customers and avoiding missed opportunities to create value for ratepayers.[21]

SDG&E also notes that Section 399.21(a)(3) does not require the disputed formula and states that removing the price floor formula is not equivalent to removing safeguards because objective data, enumerated quantitative and qualitative criteria, and Commission supervision remain in place.[22] [23] According to SDG&E, current market prices are among the best measures of the fair market value of RECs and provide a reasonable basis for evaluating transactions. Further, SDG&E argues that the authorities cited by Cal Advocates do not support rejection of the proposal, as they concern process inconsistencies unrelated to SDG&E's proposal, a transaction that did not follow Commission approved protocols, and did not require price floors or ceilings.[24]

SDG&E maintains that selling excess RECs at reasonable market-based prices can generate revenue for ratepayers, while retaining RECs that are not needed for compliance produces no revenue or savings.[25] For that reason, given affordability concerns, SDG&E argues that the Commission should allow flexibility to respond to market conditions.

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[21] SDG&E Reply Comments at 2 and 3.

[22] Section 399.21(a)(3) provides:

All revenues received by an electrical corporation for the sale of a renewable energy credit shall be credited to the benefit of ratepayers.

[23] SDG&E Reply Comments at 3.

[24] SDG&E Reply Comments at 4.

[25] SDG&E Reply Comments at 4 and 5.

5.2. Ava Community Energy Comments on PG&E's Draft 2026 RPS Plan

Ava Community Energy requests that the Commission establish "clear predictable regulatory guardrails around PG&E's portfolio management," arguing that PG&E's short-term product sales create volume uncertainty for load-serving entities (LSEs) reliant on the VAMO framework.[26] Ava Community Energy supports PG&E's need for flexibility in managing its RPS portfolio but argues that PG&E's pre-allocation RPS sales can create significant uncertainty for LSEs that rely on VAMO deliveries for compliance planning.[27] Ava Community Energy states that these sales can reduce expected VAMO deliveries after LSEs have already planned their RPS procurement, potentially forcing costly replacement purchases late in the compliance period.[28] Ava Community Energy cites its own 2025 experience, when PG&E's 2024 sales reduced its expected VAMO deliveries by 75 percent.[29]

Ava Community Energy supports PG&E's proposal to prioritize short-term sales from its bundled customer share after VAMO allocations are determined.[30] If pre-allocation sales remain permitted, Ava Community Energy recommends regular reporting, including monthly updates on projected portfolio generation and expected effects on VAMO shares, so LSEs can plan their compliance obligations with greater predictability.[31]

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[26] Ava Community Energy Comments at 1.

[27] Ava Community Energy Comments at 1-2.

[28] Ava Community Energy Comments at 2-4, 7.

[29] Ava Community Energy Comments at 5.

[30] Ava Community Energy Comments at 8.

[31] Ava Community Energy Comments at 9.

In its reply, PG&E argues that Ava Community Energy's request for monthly VAMO information is inconsistent with the VAMO program.[32] VAMO was designed to allocate a variable and ideally shrinking Power Charge Indifference Adjustment (PCIA)-eligible RPS portfolio, not to provide volume certainty.[33] PG&E may conduct third party sales and other portfolio optimization activities that reduce or eliminate VAMO volumes, so Ava Community Energy is not entitled to guaranteed deliveries.[34]

PG&E also argues that Ava already receives reasonable notice through solicitations, advice letters, regulatory filings. Further, monthly delivery forecasts would be unreliable because of renewable generation variability, REC creation delays, portfolio changes, and third-party sales. Nevertheless, PG&E is willing to provide an annual non-binding year ahead forecast of expected volumes. The forecast would be informational only and should not be relied upon for RPS compliance planning.

As noted by PG&E, the Commission expressly recognized that forecasted, vintaged, annual load shares and the RPS energy deliveries "will change from year to year based on the updated forecasts of vintaged, annual loads and the actual RPS energy volumes realized in each year of the allocation term."[35] The requested monthly delivery forecast granularity and forecast frequency may be burdensome, unreliable, and is not required by the VAMO framework. PG&E expressed willingness to provide information-only non-binding updates to

[32] PG&E Reply Comments at 9.

[33] PG&E Reply Comments at 9.

[34] PG&E Reply Comments at 9.

[35] D.21-05-030 Conclusion of Law 7(e).

remedy Ava Community Energy's concerns outside the proceeding.[36] The Commission finds this approach reasonable and encourages PG&E to continue collaborating with its counterparties to remedy concerns about fluctuations in VAMO deliveries.

6. Investor-Owned Utilities' Draft 2026 RPS Plans

SB 100 set a requirement for retail sellers to meet a 60 percent RPS procurement target by 2030. D.19-06-023 implemented the revised procurement quantity requirements established by SB 100 and specified that, for the 2021-2024 compliance period, retail sellers must procure at least 44 percent of their retail sales from eligible renewable energy resources by December 31, 2024. The decision also required that procurement in the intervening years follow the quantities calculated by the straight-line trend method.[37]

The three IOUs—PG&E, SCE, and SDG&E—reported RPS progress that met or exceeded the program's procurement requirements for the 2021–2024 compliance period (CP 4). For 2025, before applying banked RECs toward RPS compliance, the utilities reported annual gross RPS positions equal to 38.3% of PG&E's load, 46.4% of SCE's load, and 81.2% of SDG&E's load.[38] For the compliance period 2025-2027 retail sellers must procure no less than 52 percent of their retail sales from eligible renewable energy resources by December 31, 2027.

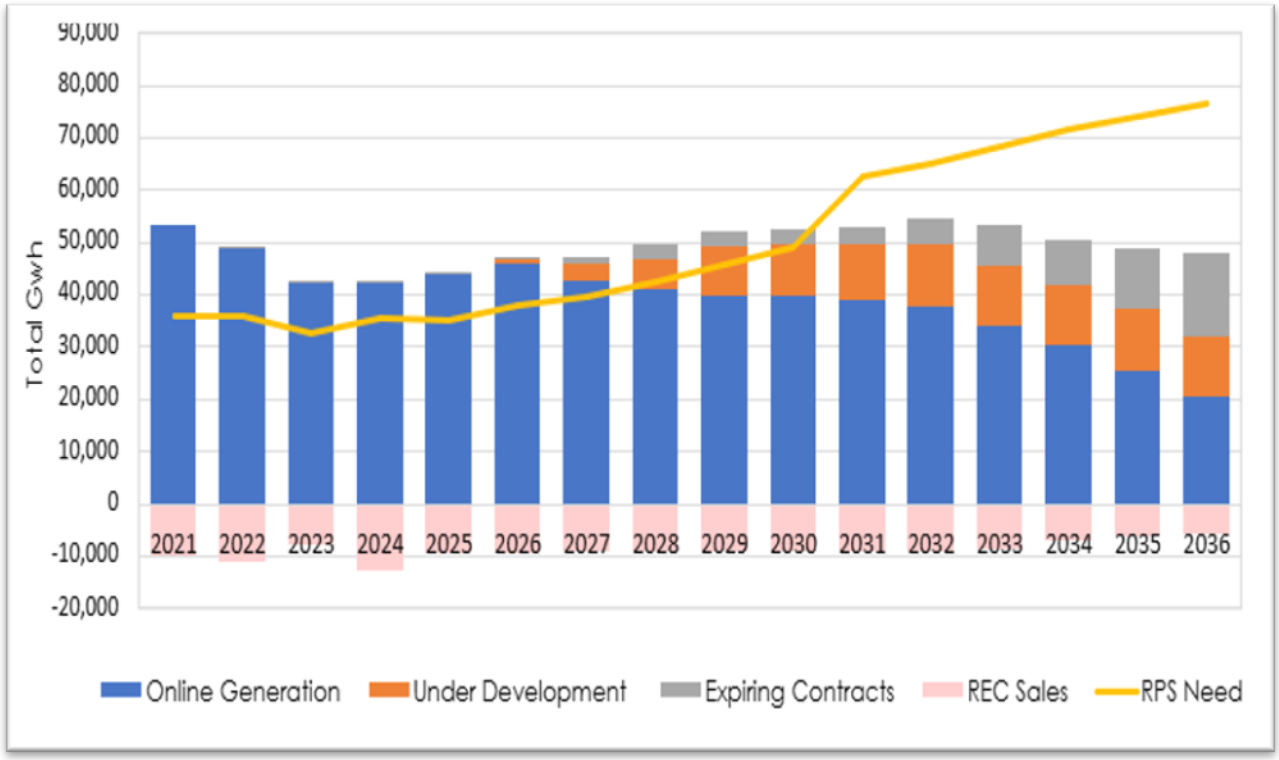
[36] PG&E Reply Comments at 12 and 13.

[37] D.19-06-023 at Ordering Paragraph (OP) 1.

[38] PG&E Draft 2026 RPS Plan at Appendix C.2; SCE Draft 2026 RPS Plan at Appendix C.1 and C.2; SDG&E Draft 2026 RPS Plan at Appendix 1a and 1b.

Figure 1 below summarizes the large IOUs' actual and forecasted progress toward meeting the 60 percent RPS mandate by 2030.

Figure 1: Aggregated Investor-Owned Utilities' Progress Toward 60 Percent Renewables Portfolio Standard



6.1. Pacific Gas and Electric Company's Draft 2026 RPS Plan

PG&E's Draft 2026 RPS Plan contains all the required elements listed in Table 1 of the 2026 ACR and is approved. PG&E must seek Commission approval of any RPS contracts consistent with existing procedures by submitting a Tier 3 or Tier 1 Advice Letter.

The most significant changes between PG&E's Final 2025 RPS Plan and its Draft 2026 RPS Plan include the following:

- Updated forecasted RPS procurement needs and considered potential impact of Rulemaking 25-02-005;

- Requested approval to sell RECs from PG&E's retained bundled share under VAMO;
- Requested continued authority to renegotiate existing contracts and permission to terminate contracts, when necessary;
- Revised the RPS Portfolio and Supply section to conform with 2026 ACR template, and to reflect changes to PG&E's forecasted RPS procurement need and potential outcomes on pre-2019 banked RECs value;
- Added uncertainty modeling to address data center load growth;
- Updated potential short-term transaction evaluation methodologies.[39]

In its Draft 2026 RPS Plan, PG&E reports a sustained annual short RPS position through the forecast horizon, primarily resulting from the VAMO processes.[40] PG&E has historically relied on banked RECs. Because the Commission was considering in R.25-02-005 whether bundled customers should compensate departing load customers for the use of pre-2019 banked credits, and the compensation amount was unknown when the 2026 RPS Plans were filed,[41] PG&E argued that using these credits may be more expensive than purchasing short-term RPS products or accelerating long-term procurement.[42] PG&E is therefore requesting broad authority to purchase short-term and long-term RPS

[39] *See* Table 1-1, PG&E Draft 2026 RPS Plan at 2, for the complete list of changes.

[40] PG&E Draft 2026 RPS Plan at 2, 3 and 5.

[41] D.26-09-047 affirmed the Commission's methodology of valuing RECs generated prior to 2019 and banked but used for IOU bundled customer compliance in later years at zero dollars when calculating the IOU's PCIA.

[42] PG&E Draft 2026 RPS Plan at 3.

products, manage portfolio costs, support customer affordability, and reduce future compliance risk.[43]

PG&E also states that its load forecast was revised to account for data center load development, including delays to incremental load materializing, updated assumptions on which LSE will serve large data center load, changes to energy efficiency forecast methodology, and Electric Vehicle (EV) adoption.[44]

In PG&E's opinion, Commission procurement orders may improve PG&E's future RPS position. PG&E reports that it has procured more than 5,700 megawatts (MW) under the mid-term reliability requirements, including about 1,200 MW of RPS-eligible resources.[45] Recently, D.26-02-057 required PG&E to procure 1,077 MW of net qualifying capacity,[46] some which may come from RPS-eligible resources. PG&E is also procuring greenhouse gas (GHG) free resources to meet SB 100, SB 1020, and IRP requirements. A significant share of these resources may qualify under the RPS program. Even after considering all existing resources, expected mandated procurement, and updated forecast, PG&E projects an annual RPS shortage throughout the forecast period.

PG&E expects to meet its compliance obligations through a combination of banked credits, new purchases, and portfolio sales. Its reliance on banked credits will depend on whether they are less expensive than alternative procurement options.

[43] PG&E Draft RPS Plan at 3-4.

[44] PG&E Draft 2026 RPS Plan at 4.

[45] PG&E Draft 2026 RPS Plan at 4.

[46] D.26-02-057 Attachment A.

As reported in its Draft 2026 RPS Plan, PG&E's RPS portfolio costs are expected to average about $1.9 billion per year during the period 2026-2036.[47]

Overall, the Commission finds PG&E's portfolio management strategy reasonable and approves its Draft 2026 RPS Plan as modified. Similar to last year's strategy, the portfolio management strategy aims to meet short-term and long-term RPS requirements while seeking economical transactions that will promote affordability goals and optimize its RPS portfolio. The following sections primarily address PG&E's requests that require Commission approval. PG&E must update its Draft RPS Plan as directed below.

6.1.1. Authority to Transact RPS Resources

In its Draft 2026 RPS Plan, PG&E requests continued authority to transact RPS products for both short-term (up to, and including five years in terms), intermediate-term (greater than five years, but less than 10 years), and long-term (10 years in terms or greater) bundled and unbundled RPS products.[48] PG&E's request covers purchases and sales to meet RPS or other portfolio needs including but not limited to capacity, energy, GHG-free energy, GHG-emissions reductions, other Commission-issued procurement-related orders and/or managing PG&E's portfolio for bundled customer affordability. This request also includes buying and selling short-term RPS-eligible products, potentially with deliveries within the same year.

PG&E states that it does not have any immediate RPS procurement need because of its existing RPS bank, but additional procurement could improve customer affordability, relative to the use of the bank, while meeting RPS

[47] PG&E Draft 2026 RPS Plan at 126.

[48] PG&E Draft 2026 RPS Plan at 12.

compliance.[49] PG&E seeks flexibility to buy or sell short-term RPS products to manage project delays, excess supply, and portfolio needs. PG&E also seeks authority to procure earlier due to uncertainties such as data center load growth, federal policy changes, project development risks, costs, and future compliance needs.[50]

The Commission finds PG&E's request reasonable because it provides flexibility to manage RPS compliance, portfolio needs, and procurement risks under unknown future conditions. Allowing both short-term and longer-term transactions may help mitigate project delays, and changing load forecasts while supporting bundled customer affordability. PG&E's request for authority to procure short term and long term RPS resources is approved. PG&E must seek approval from the Commission via Tier 1 Advice Letters for any short-term RPS transactions under this authority. For any longer transactions, PG&E must seek approval via the Tier 3 Advice Letter process.

6.1.2. Authority to Renegotiate Existing Contracts

PG&E requests authority to renegotiate its existing contracts to manage its RPS portfolio. PG&E states that it would pursue contract amendments including, but not limited to, contract price reductions, extensions of contract terms, increased buyer curtailment flexibility, repowering of existing facilities and/or upgrades of existing facility equipment, contract terminations, existing facility and equipment upgrades, or a combination of these amendments.[51] PG&E

[49] PG&E Draft 2026 RPS Plan at 12.

[50] PG&E Draft 2026 RPS Plan at 13.

[51] PG&E Draft 2026 RPS Plan at 13.

clarifies that any potential upgrades or change in commercial terms may result in existing resources potentially being shut down temporarily or permanently.

PG&E's request aims to provide value to the ratepayers and optimize its portfolio, and therefore, is approved. If any contract amendments, restatements, or contract terminations result from renegotiations, PG&E must submit a Tier 3 Advice Letter for the Commission's review and approval.

6.1.3. Authority to Transact RPS Products via Bilateral Negotiations

PG&E requests to maintain authority to transact bilaterally for the purchase and sale of short, long, or intermediate-term RPS products, and/or to renegotiate or terminate existing contracts. PG&E states that the continuance of this authority will allow PG&E to take advantage of opportunities to optimize its portfolio in support of customer affordability.[52]

PG&E states that in the current market it frequently competes with other market participants to purchase or sell RPS products. PG&E believes that being allowed to transact bilaterally would align PG&E's transactional authority with other market participants and help PG&E to manage its portfolio more effectively while meeting its requirements at competitive costs for bundled customers.[53]

Given the increasing competitiveness in renewable energy markets, the Commission finds PG&E's request to enter into bilateral negotiations reasonable. Bilateral negotiations may continue to help fill specific gaps in PG&E's portfolio, e.g. particular delivery shape, that may not be available in solicitations and may

[52] PG&E Draft 2026 RPS Plan at 14.

[53] PG&E Draft 2026 RPS Plan at 14.

yield favorable prices to benefit ratepayers. PG&E must continue to submit Tier 3 Advice Letters for any intermediate or long-term RPS contracts resulting from bilateral negotiations, including amendments and/or terminations of existing agreements. PG&E must continue to submit Tier 1 Advice Letters for short-term transactions.

6.1.4. Authority to Participate in Third-Party Competitive Solicitations

PG&E intends to transact short and long-term RPS products and requests continued authority to participate in other market participants' or third-party competitive solicitations.[54]

Given PG&E's RPS portfolio needs, its request for authority to bid into other market participants' or third-party competitive solicitations is reasonable and granted. PG&E must submit Tier 3 Advice Letters for approval of intermediate and long-term transactions and Tier 1 Advice Letters for short term transactions.

6.1.5. Authority to Transact via Brokers and Exchanges

PG&E requests continued authority to conduct RPS transactions through brokers and exchanges.[55] PG&E states that "this authority will support a level playing field and permit PG&E to access potentially more cost-effective products, therefore allowing PG&E to implement its portfolio optimization strategy to meet its RPS requirements and other portfolio needs while maximizing bundled customer affordability."[56]

[54] PG&E Draft 2026 RPS Plan at 14.

[55] PG&E Draft 2026 RPS Plan at 15.

[56] PG&E Draft 2026 RPS Plan at 15.

PG&E's request is reasonable and approved. Given PG&E's RPS procurement needs, PG&E is authorized to procure and sell short-term and long-term RPS products through brokers and exchanges. PG&E must submit Tier 3 Advice Letters for approval of long-term transactions and Tier 1 Advice Letters for short-term transactions.

6.1.6. Authority to Retire RECs for Low Carbon Fuel Standard Credits

PG&E requests continued authority to retire eligible RECs to claim incremental LCFS Credits, using the resulting revenues to support expanding transportation electrification programs. This authority, including flexibility to use RECs from its retained voluntary allocation bundled share and broader PCIA eligible RPS portfolio, was previously approved in D.23-12-008, D.24-12-035, and D.25-12-025.

As EV adoption continues to increase, PG&E expects greater participation in existing and future programs, along with a broader range of barriers to transportation electrification.[57] According to PG&E, to increase the amount of credits and credit revenues to fund the LCFS programs, claiming LCFS credits through the retirement of RECs provides a means to demonstrate that PG&E is utilizing zero carbon-intensity electricity for EV related charging.

PG&E's request is reasonable and approved. PG&E may retire RECs for LCFS credits from either the PCIA-eligible portfolio or its own shares of voluntary allocations, or both.

[57] PG&E Draft 2026 RPS Plan at 15.

6.1.7. Authority to Sell Short-Term RPS Products Indexed to PCC1 Final Market Price Benchmark

PG&E requests authority to sell short-term RPS products from its retained bundled share of its voluntary allocation at a price indexed to the applicable final PCC 1 MPB.[58]

As explained in PG&E's Draft 2026 RPS Plan, PG&E has two ways to sell excess volumes from its PCIA eligible RPS portfolio, and each affects customers differently. Selling resources before allocation allows the sale proceeds to be shared across customers, but it can create uncertainty for load serving entities that expect to receive those volumes through the VAMO process. Selling instead from PG&E's retained bundled share preserves the volumes available for VAMO allocations and therefore provides greater certainty to departed load customers and other VAMO participants. However, under the current structure, bundled customers bear the risk that the sale price may differ from the RPS MPB used to value the retained resource. Allowing PG&E to sell from its retained bundled share at prices indexed to the RPS MPB is intended to address both concerns. It would give PG&E flexibility to sell RPS products when needed for portfolio management, while limiting the potential cost exposure to bundled customers and avoiding disruption to volumes expected to be available through VAMO.

Because this approach would allow PG&E to manage its RPS portfolio while reducing bundled customer cost exposure and avoiding volume uncertainty for load serving entities and other parties participating in the VAMO process, the Commission finds PG&E's request reasonable and approves it.

[58] PG&E Draft 2026 RPS Plan at 16.

PG&E must seek Commission approval of any short-term transactions conducted under this authority by submitting Tier 1 Advice Letters.

6.2. Southern California Edison Company's Draft 2026 RPS Plan

SCE's updated Draft 2026 RPS Plan contains all the required elements listed in Table 1 of the 2026 ACR. SCE's updated Draft 2026 RPS Plan is approved.[59] SCE must seek Commission approval of any RPS contracts consistent with existing procedures by submitting Tier 3 or Tier 1 Advice Letters.

The most significant changes between SCE's Final 2025 RPS Plan and its Draft 2026 RPS Plan include the following:

- SCE updated its procurement needs analysis for compliance periods five, six, and seven, showing a need for RPS-eligible resources to meet compliance requirements through CP 7 (2031-2033).[60]
- SCE updated its plan to show how it will manage its portfolio to meet long-term and short-term RPS-eligible procurement.[61]
- SCE proposed changes to its 2026 Pro Forma Renewable Power Purchase Agreement (PPA).[62]

In its Draft 2026 RPS Plan, SCE forecasts a need for additional RPS-eligible resources through Compliance Period 7 (2031-2033).[63] According to SCE's analysis, SCE would fall below its 95 percent confidence threshold for meeting

[59] SCE updated its Draft 2026 RPS Plan to revise Appendix O, Transmission and Interconnection Delay Reporting, and to make changes to its written plan reflecting those revisions, and to make one change to Appendix K, 2026 Pro Forma PCC 1 REC Confirmation.

[60] SCE Draft 2026 RPS Plan at 1.

[61] SCE Draft 2026 RPS Plan at 2-10.

[62] SCE Draft 2026 RPS Plan at 10-12.

[63] SCE Draft 2026 RPS Plan at 1 and 26.

CP 6 requirements and would not meet CP 7 requirements under a deterministic analysis. Therefore, SCE plans ratable procurement for CP 7 to address post-2030 needs and capture available tax credit benefits before they sunset.[64] SCE's analysis includes the executed contracts SCE has signed to meet its IRP mid-term reliability (MTR) procurement requirements.[65]

SCE states that federal and state policies supporting clean air, GHG emissions reductions, and renewable energy generally lead to increases in expected load. SCE's latest load forecast is approximately 10.8 percent lower annually from 2029 to 2032, on average, than its previous forecast, primarily reflecting reduced policy support for clean energy and electrification.[66] SCE also notes that increased transportation and electrification, departed load migration to and from CCAs, and macroeconomic factors can affect changing sales forecasts.

SCE intends to meet its compliance obligations through a combination of new and existing RPS resource purchases as well as PCC 1, 2, and 3 REC purchases; banked credits; and additional RPS-eligible procurement through clean energy and reliability solicitations authorized in D.24-02-047 and D.26-02-057.[67]

As noted in its Draft 2026 RPS Plan, SCE's RPS portfolio costs are expected to average about $2.2 billion per year during the period 2026-2036.[68]

[64] SCE Draft 2026 RPS Plan at 1-2.

[65] SCE Draft 2026 RPS Plan at 3.

[66] SCE Draft 2026 RPS Plan at 44.

[67] SCE Draft 2026 RPS Plan at 3-8 and 73-74.

[68] SCE Draft 2026 RPS Plan at Appendix D.

Overall, the Commission finds SCE's portfolio management strategy reasonable and approves its RPS Plan as modified. SCE's Draft 2026 RPS Plan demonstrates a well-reasoned approach to meet short- and long-term RPS requirements. The following sections primarily address SCE's requests that require Commission approval.

6.2.1. Southern California Edison Company's Request for Authority to Procure Additional RPS-Eligible Resources

SCE requests authority to procure additional RPS-eligible new and existing resources using long-term contracts through RPS solicitations and bilateral negotiations.[69] SCE states that it will meet some of its forecasted RPS need through CP 7 and earlier compliance periods through solicitations authorized by the IRP Decisions. However, SCE adds that this procurement will not be sufficient to meet future RPS compliance requirements. SCE lists factors necessitating additional RPS procurement, including the inherent risk of developing new generation projects, the annual variation in load and existing renewable generation, and the need to procure additional resources to cover risk and increasing load through CP 7.[70]

SCE argues that several factors are making it harder and more expensive to develop and procure new RPS-eligible renewable resources in California.[71] These constraints increase competition for existing resources and create a need for greater procurement flexibility. The key challenges described by SCE are as follows:

[69] SCE Draft 2026 RPS Plan at 5 and 6.

[70] SCE Draft 2026 RPS Plan at 5.

[71] SCE Draft 2026 RPS Plan at 6.

1. Tariffs and trade policy: Changing import tariffs could raise project equipment costs and create uncertainty around financing and project completion dates, particularly for Compliance Period 6 and 7.[72]
2. Permitting delays: Bureau of Land Management delays are slowing contracting and construction. Some developers are seeking contractual termination rights if delays continue.[73]
3. Federal tax credit changes: Reductions or elimination of certain elements of Investment Tax Credit and Production Tax Credit benefits have prompted developers to seek contract price adjustments and may delay contract execution.[74]
4. Interconnection bottlenecks: High volume of California Independent System Operator (CAISO) interconnections requests continue to delay projects.[75]
5. Competition: There is increasing competition for RECs as LSEs need more RECs to satisfy RPS requirements, while some utilities and commercial customers have clean energy targets beyond regulatory requirements.[76]

Noting the pending proceeding before the Commission to value pre-2019 banked RECs, SCE adds that any change in valuations of these banked RECs could require SCE to reconsider its procurement strategy.[77] SCE further notes that SCE's latest bundled sales forecast is about 9.1 percent lower on average for 2026 through 2036 than the forecast used in its 2025 RPS Plan.[78] Changes in

[72] SCE Draft 2026 RPS Plan at 6.

[73] SCE Draft 2026 RPS Plan at 6 and 7.

[74] SCE Draft 2026 RPS Plan at 7.

[75] SCE Draft 2026 RPS Plan at 7.

[76] SCE Draft 2026 RPS Plan at 7.

[77] SCE Draft 2026 RPS Plan at 7 and 8.

[78] SCE Draft 2026 RPS Plan at 8.

electrification and economic conditions could cause future procurement needs to vary substantially.

Given these uncertainties, SCE asks the Commission for authority to procure both new and existing RPS resources through CP 7 using previously approved methods, including RPS solicitations and bilateral negotiations.

Upon review, the Commission concludes that SCE's request for additional procurement is adequately justified. Based on the supporting factors SCE presented in its Draft 2026 RPS Plan, SCE's request to procure new and existing RPS eligible resources using long or short-term contracts is reasonable and approved. Any Tier 3 Advice Letter to be submitted by SCE must show that the contracts executed under this procurement authority are RPS eligible and meet either RPS needs, portfolio goals from their IRP filing, or formally adopted IRP portfolio, or any remaining IRP procurement needs for orders issued through the RPS implementation year. Portfolio goals may include system reliability, greenhouse gas emission targets, or portfolio resource mix optimization. SCE must continue to strike the appropriate balance between meeting RPS needs in a cost-effective manner and meeting regulatory procurement requirements.

6.2.2. Southern California Edison Company's Request for Authority to Purchase and Sell Portfolio Content Category 1, Portfolio Content Category 2, and Portfolio Content Category 3 Renewable Energy Credits

SCE requests continued authority to engage in short-term and long-term transactions of PCC 1, PCC 2, and PCC 3 RECs to meet its RPS targets in the most affordable way for its customers. SCE proposes upfront and achievable standards and criteria for short-term REC transactions using the Tier 1 advice

letter process, while long-term purchases would be reviewed as Tier 3 advice letters.[79] The requested authority, if granted, would provide additional flexibility to SCE to meet its RPS needs in CP 6 and CP 7.

To facilitate the purchase and sale of RECs, SCE requests authority to issue solicitations, participate in other market participants' solicitations, and to enter into bilateral contracts. Further, to remain competitive with other retail sellers, SCE also requests authority to purchase RECs through brokers and exchanges.

SCE has a need for RPS eligible resources to meet the compliance target for CP 6 and beyond. Due to the inherent risk associated with completion of new projects, variations in load and existing renewable generation, and four years of time between now and the need to meet the 2030 CP 6 goal, SCE may need flexibility to purchase and sell RECs to be able to meet its RPS goals. Therefore, the Commission finds SCE's request reasonable and approves it. SCE is authorized to purchase and sell PCC 1, PCC 2, and PCC 3 RECs using solicitations, other market participants' solicitations, bilateral negotiations, and brokers and exchanges. SCE may submit Tier 1 or Tier 3 advice letters for approval of short-term transactions.[80] For long-term transactions, SCE shall continue to use the Tier 3 advice letter process. All transactions, including bilateral transactions, will be required to demonstrate consistency with Commission decisions and a strong showing of reasonableness.

If an intervening decision from the Commission in the IRP rulemaking approves SCE's proposal regarding short-term REC procurement, then that

[79] SCE Draft 2026 RPS Plan at 9 and 45.

[80] *See* D.14-11-042.

decision may supersede the short-term REC procurement standards approved in this decision.

6.2.3. Southern California Edison Company's Request for Approval of Protocols

In its Draft 2026 RPS Plan, SCE submits for Commission approval its procurement protocols for new and existing resources,[81] REC transaction protocols,[82] and least-cost best-fit (LCBF) evaluation methodology.[83]

Upon review, the Commission finds SCE's proposed protocols reasonable and approves them.

6.2.4. Southern California Edison Company's Request for Approval of Pro Forma Agreements

In its Draft 2026 RPS Plan, SCE proposes revisions to these agreements: Pro Forma Renewable PPA; Pro Forma PCC 1 REC Agreement; and Pro Forma PCC 3 REC Agreement.[84]

SCE's 2026 Pro Forma Renewable PPA is based on the technology neutral pro forma contract approved by the Commission in Resolution E-5004 for contracting for In-Front-of-Meter renewable energy resources and incorporates provisions from SCE's MTR contracts and contracts from SCE's Clean Energy Solicitation authorized under D.24-02-047.[85] SCE explains that there have been changes to the 2025 Pro Forma Renewable PPA to incorporate recent changes to the Technology Neutral Pro Forma contract to harmonize language with the

[81] SCE Draft 2026 RPS Plan at 78, Appendices I.1, J.1.

[82] SCE Draft 2026 RPS Plan at 78, Appendix M.1.

[83] SCE Draft 2026 RPS Plan at 79, Appendix H.1.

[84] SCE Draft 2026 RPS Plan at 10 through 13.

[85] SCE Draft 2026 RPS Plan at 10.

version used in SCE's 2024 Clean Energy solicitation. The substantive terms and conditions remain consistent with the 2024 Pro Forma Renewable PPA, except for specific changes noted in the summary table of major changes to pro forma contracts. Relatively minor changes have been made to the 2025 Pro Forma PCC 1 Confirmation and pro forma PCC 3 REC Agreement.[86]

Upon review, the Commission finds that the substantive terms and conditions of the pro forma agreements remain consistent with the 2025 Pro Forma agreements and the submitted changes are reasonable. Therefore, SCE's Pro Forma Renewable PPA, Pro Forma PCC 1 REC Agreement, and Pro Forma PCC 3 REC Agreement submitted in its Draft 2026 RPS Plan are approved.

6.2.5. Southern California Edison Company's Request for Approval to Retire Renewable Energy Credits for Low Carbon Fuel Standard Funded Programs

SCE seeks Commission authorization in its Draft 2026 RPS Plan to participate in claiming incremental LCFS credits through the retirement of RECs. SCE expects that customer participation in SCE's LCFS-funded programs will increase over time as EV adoption increases and SCE's program operations mature.[87] SCE notes that it first received approval in its 2022 RPS Plan to claim incremental LCFS Credits through the retirement of RECs demonstrating the use of zero carbon-intensity electricity for transportation electrification charging.

If SCE has sufficient PCC 3 RECs to claim incremental LCFS credits, it plans to retire those RECs and compensate bundled customers for their fair market value. SCE proposes valuing the RECs using the higher of the current

[86] SCE Draft 2026 RPS Plan at 13.

[87] SCE Draft 2026 RPS Plan at 117.

market price for RECs, or the three-month weighted average Platts price.[88] If that calculation does not adequately represent fair market value, SCE may apply a reasonable adder to ensure bundled customers are fully compensated. Any value remaining after compensating bundled customers would go to the LCSF program.[89]

SCE's request is reasonable and approved. SCE is authorized to retire RECs for LCFS-funded programs.

6.2.6. Southern California Edison Company's Request to Discontinue Providing Certain Information

In its Draft 2026 RPS Plan, SCE requests authorization to discontinue including informational time-of-delivery (TOD) heat maps in future RPS Plans.[90] The heat maps were initially directed in D.19-02-007[91] and originally required to show developers when electricity deliveries were relatively valuable, helping them design projects and bids accordingly. SCE has continued to provide them and includes updated 2025 and 2028 heat maps in its 2026 RPS Plan.

SCE argues that these maps are no longer necessary for several reasons. First, TOD factors no longer affect contract payments.[92] Because RPS contracts use a flat energy payment structure with a TOD factor of 1.0, heat maps do not affect seller compensation or bid pricing. Second, the underlying information is

[88] Platts is a third-party daily commodity price assessment that provides market data and analysis for various commodities, including renewable energy.

[89] SCE Draft 2026 RPS Plan at 118.

[90] SCE Draft 2026 RPS Plan at 14, 115-116.

[91] D.19-02-007 at 99.

[92] SCE Draft 2026 RPS Plan at 115 and 116.

already public.[93] General Rate Case (GRC) filings provide marginal energy cost assumptions used to create heat maps, while CAISO hourly market prices provide additional information about the relative value of energy by time. Third, most renewable resources cannot shift production in response to TOD-based delivery preferences.[94] Resources such as solar and wind generally cannot change when they generate in response to TOD signals. SCE asserts that producing the maps requires additional work without providing significant additional information to bidders.[95]

The Commission finds SCE's supporting arguments convincing and concludes that the informational TOD heat maps are no longer fulfilling the intent behind their requirement and their continued inclusion in the RPS Plan is unnecessary and burdensome. Starting with the 2027 Draft RPS Plans, all IOUs may discontinue providing the informational TOD heatmaps in their RPS Plans.

6.2.7. Southern California Edison Company's Request to Discontinue Reporting on GTSR Programs

SCE has traditionally reported on four Green Access Programs in its annual RPS Plans: 1) Disadvantaged Communities Green Tariff (DAC-GT); 2) Community Solar Green Tariff (CSGT); 3) Green Tariff Shared Renewables (GTSR) Enhanced Community Renewables program (ECR or CR by SCE); and 4) GTSR Green Rate tariff.

[93] SCE Draft 2026 RPS Plan at 116.

[94] SCE Draft 2026 RPS Plan at 116.

[95] SCE Draft 2026 RPS Plan at 115.

D.24-05-065 closed the GTSR-ECR to new customer enrollment,[96] terminated the GTSR Green Rate tariff, terminated the CSGT program,[97] and modified the DAC-GT program.[98] While SCE continues to report on all Green Access Programs in its Draft 2026 RPS Plan, SCE proposes to limit future reporting in its RPS Plan to the GTSR program (consistent with D.15-01-051) to the extent the Commission continues to require such reporting. However, given the D.24-05-065's termination of the GTSR programs, SCE proposes that the Commission authorize SCE to discontinue RPS Plan reporting on GTSR.[99]

In light of the Green Access Programs ceasing to operate on an ongoing basis, the Commission concludes that there is little or no value in continuing to track these programs through the annual RPS Plans. Therefore, SCE's request to discontinue reporting on GTSR programs in its RPS Plans is approved. Starting with the 2027 Draft RPS Plans, SCE and SDG&E may discontinue reporting on GTSR programs in their RPS Plans. However, PG&E must continue reporting on its GTSR program because D.21-12-036 allows PG&E to use a borrowed pool of resources from its RPS portfolio to fulfill its GTSR needs. The borrowed GTSR pool of resources must be removed from PG&E's bundled customer RPS portfolio and cannot be used to meet future RPS requirements. D.21-12-036 also requires that PG&E continue providing GTSR information in its RPS Plans until it ceases using the borrowed GTSR pool. Resolution E-5382 grants PG&E permission to continue using the borrowed GTSR pool until December 31, 2028, or when a modified Green Tariff program is operational, whichever comes first.

[96] D.24-05-065 at OP 4(b).

[97] D.24-05-065 at OP 2.

[98] D.24-05-065 at OP 3.

[99] SCE Draft 2026 RPS Plan at 14 and 106.

Thus, PG&E must continue reporting on how this borrowed pool of resources impacts its RPS position and strategy and must continue providing cost-sharing information.

6.3. San Diego Gas & Electric Company's Draft 2026 RPS Plan

SDG&E's Draft 2026 RPS Plan contains all the required elements listed in Table 1 of the 2026 ACR. SDG&E's updated Draft 2026 RPS Plan is approved with modifications. SDG&E must seek Commission approval of any RPS contracts consistent with existing procedures by submitting a Tier 3 or Tier 1 Advice Letter.

SDG&E reports that even though SDG&E met its CP 4 RPS requirements by achieving 53 percent renewable energy, load departure commencing in 2021 and the VAMO process commencing in 2023 led to significant changes in its RPS portfolio.[100] Currently, SDG&E anticipates that its RPS position will fall short beginning in the current compliance period. Accordingly, SDG&E expects to use its bank, and/or procure new and existing RPS resources during CP 5 to meet its compliance requirements for CP 5 and beyond.[101] Concurrently, SDG&E plans to continue selling unsold VAMO volumes to the extent they are not needed for compliance.[102]

SDG&E intends to meet its future RPS obligations by utilizing the bank and/or holding a solicitation, or entering into agreements to procure long-term and/or short-term resources, depending on the benefits of these transactions to

[100] SDG&E Draft 2026 RPS Plan at 21 and 22.

[101] SDG&E Draft 2026 RPS Plan at 4 and 22.

[102] SDG&E Draft 2026 RPS Plan at 4.

the ratepayers.[103] SDG&E also intends to optimize its portfolio in the near-term through both the purchase and/or sales of RECs via solicitations, bilateral sales agreements, and/or brokerages and exchanges in the form of short-term transactions.[104] SDG&E also intends to leverage other Commission ordered procurement outside the RPS program that results in RPS-eligible resources being procured.[105]

SDG&E intends to manage any potential over-procurement due to departing load by banking it for future compliance needs, terminating contracts, as appropriate, selling excess procurement, or transferring the obligation to a new party as permitted by the contract.[106]

As noted in its Draft 2026 RPS Plan, SDG&E's RPS portfolio costs are expected to average about $278 million per year during the period 2026-2036.[107]

Overall, SDG&E's procurement strategy is reasonable; it demonstrates a balanced approach to meeting short- and long-term RPS requirements and is approved with modifications to its RPS pro formas.

6.3.1. San Diego Gas & Electric Company's Request for Authority to Utilize Banked Renewable Energy Credits

SDG&E seeks the authority to utilize its banked RECs procured pre-2023 to meet RPS compliance requirements, beginning in the year SDG&E has a short position through 2036, as applicable, since doing so may be more cost-effective

[103] SDG&E Draft 2026 RPS Plan at 22-23.

[104] SDG&E Draft 2026 RPS Plan at 22-23.

[105] SDG&E Draft 2026 RPS Plan at 22.

[106] SDG&E Draft 2026 RPS Plan at 23.

[107] SDG&E Draft 2026 RPS Plan at Appendix 2.

than other available compliance options.[108] SDG&E states that it may meet compliance through 2036 by utilizing the RECs in its bank, subject to the condition that post-2018 banked RECs are utilized first before any pre-2019 banked RECs, in accordance with D.25-12-025 or a decision reached in R.25-02-005.[109]

The Commission finds SDG&E's request to use its banked RECs to meet its RPS needs is cost-effective and consistent with RPS rules and therefore approves it.

6.3.2. San Diego Gas & Electric Company's Request for Authority to Conduct Optional Procurement

As an alternative to using its banked RECs, SDG&E requests authority to conduct optional bundled renewable energy plus RECs and/or unbundled REC purchases from new or existing resources, either through short-term or long-term contracts, if doing so is more beneficial to its portfolio based on cost and need in the 2026 RPS planning cycle.[110] Towards this end, using the RNS forecast, SDG&E has set both a volumetric cap and a capacity limit on the amount of new eligible renewable resources it may procure, if it chooses to procure long-term contract resources.[111] To meet its near-term RPS compliance requirements while managing its portfolio in a cost-effective manner and supporting affordability goals, SDG&E has established a volumetric limit.[112]

[108] SDG&E Draft 2026 RPS Plan at 5.

[109] SDG&E Draft 2026 RPS Plan at 5.

[110] SDG&E Draft 2026 RPS Plan at 5.

[111] SDG&E Draft 2026 RPS Plan at 5, Appendix 1.a, Appendix 1.b.

[112] SDG&E Draft 2026 RP Plan at 5 and Appendix 15.b.

The Commission approves SDG&E's request for the option to procure RECs for compliance through solicitations, bilateral agreements, or brokers and exchanges. SDG&E must submit a Tier 1 or Tier 3 Advice Letter for review and approval of short term and long-term purchases, respectively. SDG&E must also demonstrate that contracts are RPS-eligible and that they are either needed to meet RPS needs or that the contracts are necessary to comply with IRP procurement orders.

6.3.3. San Diego Gas & Electric Company's Request for Authority to Sell Renewables Portfolio Standard Volumes

In its Draft 2026 RPS Plan, SDG&E requests authorization to sell RPS volumes from its RPS portfolio, including PCIA eligible resources; its PCIA eligible portfolio allocation; and RECs that were not required to be offered or allocated under D.21-05-030. These sales would be conducted in accordance with SDG&E's REC Sales Framework to provide customer benefits while maintaining RPS compliance.[113]

To further balance its portfolio, SDG&E may sell REC volumes from the PCIA eligible portfolio prior to the distribution of the VAMO transactions. In addition, SDG&E may sell volumes not allocated through the VAMO process if those volumes are not needed for compliance. Potential revenues from these sales could help support affordability for both bundled and unbundled customers.[114]

If SDG&E forecasts excess RECs in its portfolio, it will perform a short-term and long-term quantitative and qualitative cost benefit analysis associated

[113] SDG&E Draft 2026 RPS Plan at 5-6.

[114] SDG&E Draft 2026 RPS Plan at 5-6.

with the RECs to determine next steps, i.e., bank or sell.[115] A quantitative analysis would consider SDG&E's RPS position, time value of revenues from the potential REC sale, and the potential REC replacement cost, while a qualitative analysis would consider the impact on market liquidity and SDG&E's RPS position.[116]

Because selling excess RECs can provide savings to ratepayers while maintaining SDG&E's RPS compliance, SDG&E's request for the option to sell RPS volumes is reasonable and approved with modifications. SDG&E must limit the terms of sales to up to five years and submit a Tier 1 Advice Letter for review and approval of short-term sales.

6.3.4. San Diego Gas & Electric Company's Request for Flexibility to Buy and Sell Renewable Energy in the Same Year and/or Compliance Period

SDG&E requests approval for flexibility to manage its RPS portfolio by conducting short-term REC sales, and both short-term and long-term RPS procurement in the same year and/or compliance period. This flexibility would enable SDG&E to meet compliance obligations, respond to increasing market competition, adapt to changing market conditions, and pursue the most economic options for its bundled customers.[117] SDG&E asserts that granting this authority would allow SDG&E to respond more quickly to market dynamics and manage its portfolio in the most cost-effective manner.[118]

[115] SDG&E Draft RPS Plan at 32.

[116] SDG&E Draft RPS Plan at 32.

[117] SDG&E Draft 2026 RPS Plan at 6.

[118] SDG&E Draft 2026 RPS Plan at 6.

Because approving this strategy would allow SDG&E to manage its RPS portfolio more efficiently and cost effectively, the Commission finds SDG&E's portfolio optimization reasonable and approves it with modification. SDG&E is authorized to conduct the approved transactions in the same year.

6.3.5. San Diego Gas & Electric Company's Authorization to Participate in Requests for Offers and Utilize Both Brokers and Exchanges

To ensure a level playing field with other market participants, SDG&E requests authority to procure or sell renewable energy products through participating in RFOs and using brokers and exchanges.[119] These options may provide more value, benefits, and better ensure timely deliveries than alternative transaction modes such as bilateral contracts.[120]

SDG&E's request to procure or sell renewable energy products through RFO participation, and brokers and exchanges is reasonable and is approved. The use of brokers and exchanges for short-term RPS transactions (five years or less) requires approval with a Tier 1 or Tier 3 Advice Letter, while long-term RPS procurement transactions require approval with a Tier 3 Advice Letter.

6.3.6. Deficiencies in San Diego Gas & Electric Company's Draft 2026 RPS Plan

SDG&E's Draft 2026 RPS Plan meets the requirements of the 2026 ACR except for the deficiencies described below.

Section IV.B.1. Forecasting for Increased Transportation Electrification: The table that SDG&E provides for its annual load from transportation electrification does not compare its transportation electrification forecast results to the

[119] SG&E Draft 2026 RPS Plan at 6.

[120] SDG&E Draft 2026 RPS Plan at 58.

Integrated Energy Policy Report (IEPR) transportation electricity demand forecast results. According to the 2026 ACR, the required table and/or chart showing the retail sellers' transportation electrification forecast must also compare the retail seller's transportation electrification load results to the IEPR transportation electricity demand forecast results.[121] Therefore, SDG&E must provide a table and/or chart that also compares its transportation electrification load results to the IEPR transportation electricity demand forecast results.

Section X.A. Bid Solicitation Protocols – RPS Pro Forma Contracts: Multiple modifications are necessary to SDG&E's 2026 RPS Purchase Model PPA PCC2 Bundled Product pro forma presented in Appendix 4 of its Draft 2026 RPS Plan.

SDG&E must correct several typographical errors in its PCC 2 REC purchase pro forma (in Appendix 4) to clarify that the pro forma is a purchase contract for PCC 2 RECs. SDG&E must also add the missing terms and descriptions for PCC 2 REC purchases to the pro forma, as the existing terms lack specificity to demonstrate that the contract qualifies as a PCC 2 REC contract eligible for RPS compliance purposes.

First, Article 4.2, "CPUC Filing & Approval" of the PCC 2 REC pro forma, must be corrected as shown below in strikeouts (current language) and underlined words (revised language):

> "Within thirty (30) days after the Confirmation Effective Date, ~~Seller~~ Buyer shall file with the CPUC the appropriate request for CPUC Approval of this Agreement and possibly other agreements. ~~Seller~~ Buyer shall seek CPUC Approval of the filing, including promptly responding to any requests for information related to the request for CPUC Approval. ~~Buyer~~ Seller shall use commercially reasonable efforts to support ~~Seller~~ Buyer in obtaining CPUC Approval. ~~Seller~~ Buyer and

[121] 2026 ACR at 18 and 19.

> ~~Buyer~~ Seller have no obligation to seek rehearing or to appeal a CPUC decision which fails to approve this Agreement, or which fails to meet the requirements contained in the Condition Precedent section. Notwithstanding anything to the contrary in the Confirmation, ~~Seller~~ Buyer shall not have any obligation or liability to ~~Buyer~~ Seller or any third party for any action or inaction of the CPUC or other Governmental Authority affecting the approval or status of this Confirmation as a transaction eligible for portfolio content category, as defined in California Public Utilities Code Section ~~399.16(b)(1)~~ 399.16(b)(2)."

Second, per D.11-12-052, RPS contracts or agreements for PCC 2 RECs must demonstrate that the following three conditions are met:

1. The buyer's simultaneous purchase of energy and associated RECs from the RPS-eligible generation facility without selling the energy back to the generator;
2. The availability of the purchased energy to the buyer (i.e., the purchased energy must not, in practice, be already committed to another party); and
3. The initial contract for substitute energy is acquired no earlier than the time the RPS-eligible energy is purchased and no later than prior to the initial date of generation of the RPS-eligible energy under the terms of the contract between the buyer and the RPS-eligible generator.[122]

Although Article 6 (d)(ii) of SDG&E's PCC 2 REC pro forma seems to address the second condition above, the pro forma does not address the first condition, that the buyer cannot sell the purchased energy back to the seller. Accordingly, SDG&E must modify its PCC 2 REC purchase pro forma to ensure that all the relevant terms and conditions directed by D.11-12-052 are included. In simple terms, the buyer of the renewable energy and associated RECs cannot sell the energy back to the generator; the purchased energy must be available to

[122] D.11-12-052 at OP 2.

the buyer and must not be committed to another party; and that the substitute energy (if also provided by the seller that provides renewable energy and RECs) must be incremental and scheduled into a California balancing authority within the same calendar year as the renewable energy and REC deliveries.

Finally, the Commission finds that SDG&E modified two non-modifiable Standard Terms and Conditions (STCs) in two of its RPS pro forma contracts. Specifically, STC 1 and STC REC-3 address Commission approval requirements, with STC 1 pertaining to qualifying renewable energy resources and STC REC-3 pertaining to qualifying RECs.[123] SDG&E omitted these STCs from its "2026 RPS Purchases Model PPA PCC 2 Bundled Product" pro forma (Appendix 4) and in its "RPS Renewable Energy Credit Agreement" (Appendix 8), replacing them with a modified language for "CPUC Approval." However, consistent with our direction, SDG&E must incorporate STC 1 into its PCC 2 REC purchase pro forma and STC REC-3 in its RPS Renewable Credit Agreement pro forma, respectively, without modification. These revisions are necessary to ensure that the contracts meet the applicable requirements for compliance eligibility.

SDG&E must correct the deficiencies listed above in its Final 2026 RPS Plan.

6.4. IOU RPS Pro Forma Contracts

D.26-07-008 reaffirmed requirements for Resource Adequacy (RA) contracts, specifically for Reliability Capacity (RC) and Imbalance Reserve (IR) products, which were originally established in D.05-10-042.[124] It determined that RA resources offering RC products must submit a zero-dollar bid for capacity

[123] *See* D.08-04-009, Appendix A, at 3 and D.10-03-021, as modified by D.11-01-025 at OP 36.

[124] D.26-07-008 at OP 15 and 16.

products when participating as a Residual Unit Commitment product (or its successor) and the resource owners are not eligible for capacity-related revenue payments, except when the LSE is also the resource owner and the resource is used for RA compliance. For IR products, the Commission reaffirmed the prohibition against double-compensation: RA contracts must specify that the resource owners are not eligible for IR-related capacity revenue payments, except for the opportunity cost portion of an IR award, unless the same LSE-owner exception applies. However, IR products, while considered capacity products, are not required to be bid at zero dollars. For both RC and IR products, the above rules apply to new RA contracts executed after the effective date of D.26-07-008, and should not disturb existing RA contracts. However, the Commission also directed LSEs to undertake reasonable efforts to enforce existing contract provisions that account for the D.05-10-042 rules.[125]

The ALJ ruling, dated October 26, 2026, invited parties to respond to questions on the applicability of these RA-related provisions to new RPS contracts.

On November 2, 2026, comments were filed by Cal Advocates, PG&E, SCE, SDG&E, the Western Power Trading Forum and the Independent Energy Producers Association (WPTF-IEP), and American Clean Power – California (ACP-California).

While Cal Advocates and PG&E support expressly incorporating the requirements into new contracts, SCE and SDG&E believe their existing contracting and CAISO bidding frameworks can implement the requirements in

[125] D.26-07-008 at 115.

D.26-07-008 with respect to IR and RC products without additional standardized provisions.[126]

By contrast, WPTF-IEP recommend delaying mandatory IR provisions until pending rehearing and stay requests are resolved; otherwise, they recommend that any proposed revision undergo stakeholder review.[127]

In opposition to applying the requirements of D.26-07-008 to RPS contracts, ACP–California cautions that rigid bidding requirements could harm market efficiency, renewable dispatch, and REC costs, and favors contractual flexibility.[128]

The IOUs' proposed long-term RPS pro formas in draft 2026 RPS Plans have broad RA provisions where the "Capacity Attributes" provided by the RPS project and purchased by the IOU can be used to meet "RA obligations." However, it is the Commission's view that aligning future RPS contracts with the policy determinations and requirements of D.26-07-008 could further prevent double-compensation and maintain the integrity of RA program refinements, supporting fair market practices and regulatory objectives. Towards this end, the Commission will further review the record and address this issue in the next RPS planning cycle.

7. Small and Multi-Jurisdictional Utilities

SMJUs comprise a small but material share of California's energy market. Following a review of aggregated RNS templates in their Draft 2026 RPS Plans, the Commission finds that, collectively, the three SMJUs (BVES, PacifiCorp, and

[126] PG&E Comments, November 2, 2026, at 1-3; Cal Advocates Comments, November 2, 2026, at 1-2.

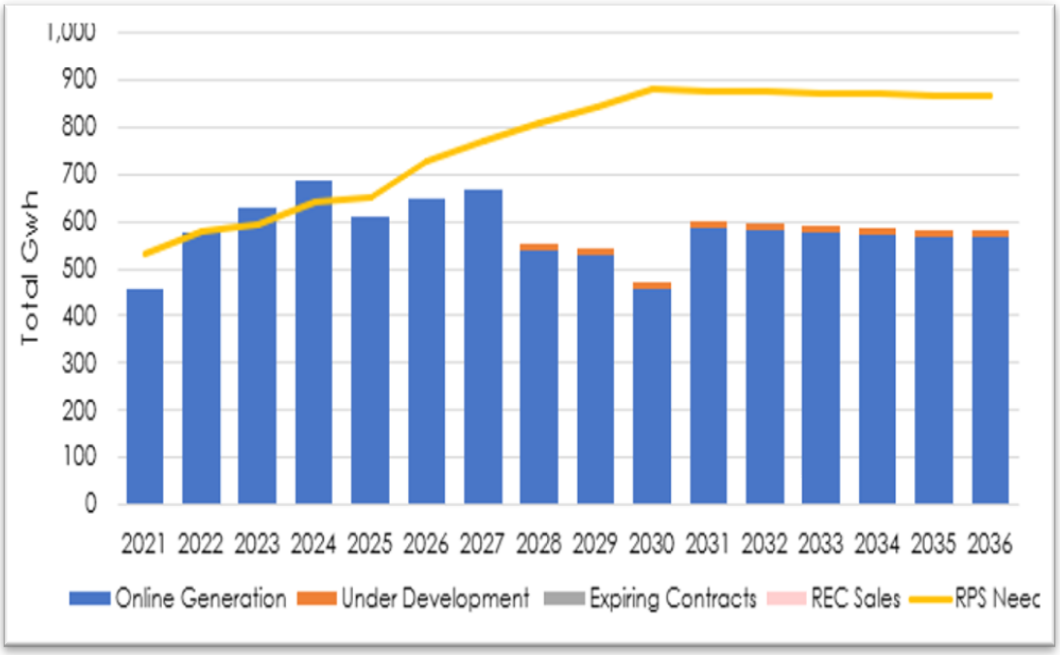
[127] SCE Comments, November 2, 2026, at 2-3, SDG&E Comments, November 2, 2026, at 2.

[128] ACP-California Comments, November 2, 2026, at 3.

Liberty) need to procure more RPS eligible renewables beginning in 2026 to meet their respective RPS requirements (*see* Figure 2).

Unlike PG&E, SCE, and SDG&E, the SMJUs can meet their RPS procurement obligations without satisfying the PCC Requirement, codified in Pub. Util. Code Section 399.16, that aims to ensure most renewable energy procurement needs are met through in-state generation. As such, SMJUs may satisfy their RPS procurement obligations through pure compliance instruments such as unbundled RECs.[129] Given their near-term need for RPS-compliant resources, the Commission continues to encourage SMJUs to consider early procurement of resources rather than last-minute purchases of unbundled RECs.

Figure 2: **Aggregated Small and Multi-Jurisdictional Utilities' Progress Towards 60 Percent Renewables Portfolio Standard**



In this section, we discuss the SMJUs' Draft 2026 RPS Plans.

[129] Pub. Util. Code § 399.17(b). The limitations on the use of each portfolio content category are explained in D.11-12-052 Sections 3.5-3.7.

7.1. Bear Valley Electric Service, Inc.'s Draft 2026 RPS Plan

Upon review, the Commission finds that BVES' Draft 2026 RPS Plan meets the requirements of the 2026 ACR. Accordingly, the Commission approves BVES' Draft 2026 RPS Plan with no modifications.

In its Plan, BVES states that it has historically met most of its RPS procurement requirement with unbundled RECs, but anticipates meeting its current and future RPS obligations using a combination of unbundled and bundled procurement, as well as owned renewable generation (the Solar Project).[130] To that point, BVES explains that its long-term PCC 1 contract with Shell Energy North America is expected to meet the bulk of its RPS needs through 2036.[131] In addition, BVES reports that it has negotiated two bilateral short-term agreements to obtain 25,000 PCC 3 RECs by 2027, and submitted an advice letter for approval of 12,000 PCC 3 RECs for delivery in 2027.[132] RECs provided under these agreements will help ensure that BVES will meet its RPS procurement obligations for the current compliance period.

BVES also notes that Application 24-05-020 to develop and own a five-megawatt solar and battery project was approved by D.25-12-024.[133] According to BVES, the approved project will help meet BVES' future RPS needs as well as allow BVES to self-supply renewable energy and capacity from a local resource to help improve grid reliability, promote price stability, reduce reliance on load

[130] BVES Draft 2026 RPS Plan at 2.

[131] BVES Draft 2026 RPS Plan at 2, 11, and 12.

[132] BVES Draft 2026 RPS Plan at 3, 12.

[133] BVES Draft 2026 RPS Plan at 2, 13.

from California's wholesale energy market, and help curtail greenhouse gas emissions.[134]

7.2. Liberty's Draft 2026 RPS Plan

Upon review, the Commission finds that Liberty's Draft 2026 RPS Plan meets the requirements of the 2026 ACR. Accordingly, the Commission approves Liberty's Draft 2026 RPS Plan with no modifications.

In its Draft 2026 RPS Plan, Liberty states that its RPS resource procurement strategy has several elements.[135] First, the 2026 Energy Services Agreement (ESA) with NV Energy, composed of a designated pool of three geothermal projects and renewables located in Liberty's service territory, will continue to provide enough supply to meet its RPS requirements for CP 5.[136] Liberty states that the ESA continues through the later of May 31, 2027, or upon the completion of new facilities that will provide Liberty with sufficient capacity to transition to taking Network Integration Transmission Service (Greenlink West) for its entire network load and Liberty directed supplies. The current online date for transmission extension is December 31, 2027. Liberty is preparing a request for proposals (RFP) to meet its long-term RPS resource needs when the 2026 NV ESA expires on December 31, 2027.[137]

Second, a significant portion of Liberty's RPS requirement will be met by generation from the Luning (50 MW) and Turquoise (10 MW) projects.[138] According to Liberty, until planned transmission upgrades become operational

[134] BVES Draft 2026 RPS Plan at 3 and 13.

[135] Liberty Draft 2026 RPS Plan at 1.

[136] Liberty Draft 2026 RPS Plan at 1, 3, 8 and 9.

[137] Liberty Draft 2026 RPS Plan at 2-3, and 12.

[138] Liberty Draft 2026 RPS Plan at 2.

and provide access to broader range of flexible renewable resources, Liberty will likely need to rely on PCC 3 REC purchases for meeting any remaining RPS compliance requirements.[139]

Liberty's Luning Expansion Project,[140] approved by the Commission in D.23-08-032,[141] will not contribute to meeting Liberty's RPS needs because the project is suspended due to several factors, including the need to fund wildfire mitigation efforts and lower costs.[142]

7.3. PacifiCorp's Draft 2026 RPS Plan

PacifiCorp's Draft 2026 RPS Plan (2026 Off-Year Supplement to its 2025 IRP Update) meets the requirements of the 2026 ACR. Accordingly, the Commission approves PacifiCorp's Draft 2026 RPS Plan with no modifications.

PacifiCorp has historically relied on existing eligible renewable energy within PacifiCorp's portfolio and unbundled PCC 3 REC procurement to meet its RPS requirements. In its current Draft RPS Plan, PacifiCorp states that it intends to meet its RPS requirements with the following options: 1) eligible renewable energy and RECs procured within PacifiCorp's system, consistent with PacifiCorp's integrated system planning for its multistate service territory and overall system operation; and 2) RECs procured through the issuance of RFPs seeking unbundled RECs that will qualify in meeting California RPS targets through the near term, as needed. PacifiCorp has not issued any additional REC RFPs since its December 2023 REC RFP.[143] Based on its 2025 IRP Update,

[139] Liberty Draft 2026 RPS Plan at 2 and 4.

[140] This is an expansion of existing Luning Solar Project providing 50 MW of solar and 249 MWh of storage.

[141] D.23-08-032 at OP 1.

[142] Liberty Draft 2026 RPS Plan at 2 and 22.

[143] PacifiCorp Draft 2026 RPS Plan at 8.

PacifiCorp has concluded that an additional REC RFP may be required to meet the compliance needs for future compliance periods.[144]

PacifiCorp states that its long-term procurement is expected to satisfy approximately 74 percent of PacifiCorp's overall renewable procurement for the prior compliance period 4 (years 2021-2024), above the 65% requirement.[145]

In its 2025 IRP Update looking out through 2035, PacifiCorp did not include model drivers to force the selection of new renewable energy resources to comply with the RPS requirements, instead it discussed using unbundled REC purchases for compliance as it would be most economical.[146]

8. Community Choice Aggregators and Electric Service Providers

The Commission approves the CCAs' and ESPs' Draft 2026 RPS Plans with modifications. To make this determination, the Commission reviewed 25 CCA and 11 ESP Draft 2026 RPS Plans for completeness, accuracy of information, and compliance with the 2026 ACR. Based on our review, CCA and ESP Draft 2026 RPS Plans complied with most of the 2026 ACR requirements. Section 8.1 and Section 8.2 of this decision provide an overview of actual and projected RPS procurement for CCAs and ESPs to meet future RPS obligations. Sections 8.3.1 through 8.3.10 of this decision provide a description of the Commission's findings and disposition of CCAs' and ESPs' Draft 2026 RPS Plans.

8.1. Community Choice Aggregators' Procurement Needs

The CCAs are projected to serve 65,000,000 megawatt-hour (MWh) of total load in 2026, collectively exceeding the 2026 RPS target. In aggregate, they are

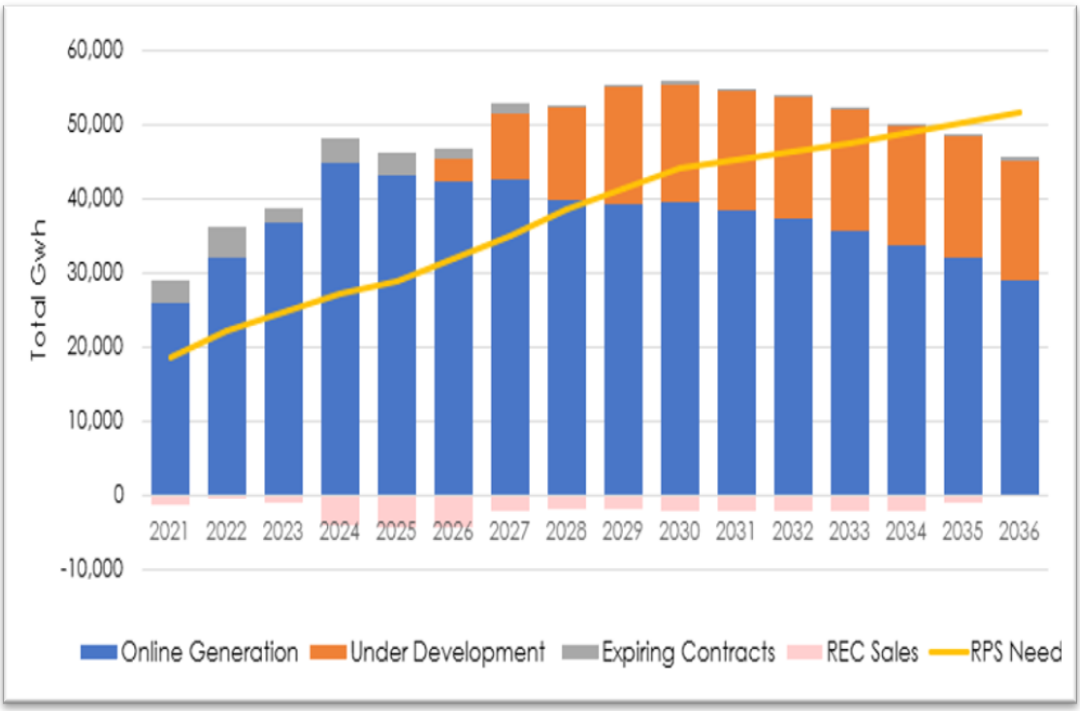
[144] PacifiCorp Draft 2026 RPS Plan at B-3.

[145] PacifiCorp Draft 2026 Plan at 11.

[146] PacifiCorp Draft 2026 RPS Plan at 10-11.

expected to meet their 2025-2027 RPS compliance target, but RPS procurement needs are anticipated to emerge starting in 2029.[147]

Figure 3: Aggregated Community Choice Aggregators' Progress Toward 60 Percent Renewables Portfolio Standard

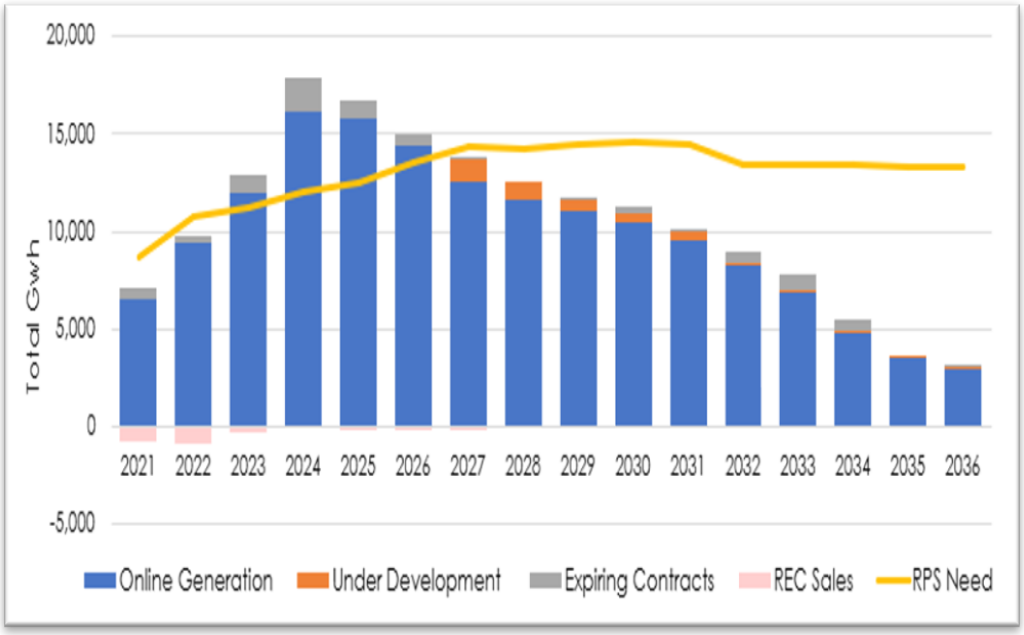


8.2. Electric Service Providers' Procurement Needs

The Commission reviewed Draft 2026 RPS Plans filed by 11 ESPs. Based on the ESPs' reporting of their RNS positions, we find that the ESPs will collectively need additional procurement to meet RPS obligations beginning in 2027, as shown in Figure 4. This is due to the ESPs' historical reliance on short-term contracts to match their RPS obligation with their overall retail sales. Some ESPs need additional RPS procurement to meet the 2025-2027 RPS compliance target as well.

[147] Based on the Commission staff analysis of aggregated retail seller 2026 RNS templates, as submitted in their Draft 2026 RPS Plans.

Figure 4: Aggregated Electric Service Providers' Progress Toward 60 Percent Renewables Portfolio Standard



8.3. Issues to Address in the Final 2026 Community Choice Aggregators' and Electric Service Providers' RPS Plans

The Commission identified several deficiencies in the CCAs' and ESPs' Draft 2026 RPS Plans. Generally, many of the same minor errors from previous RPS planning cycles continue to appear, including missing information in the transportation electrification section, mismatched or outdated values, figures, or project details in RPS Plans or its templates, and lack of clarity or details in various sections of the RPS Plans. These findings are listed in Sections 8.3.1 through 8.3.10 of this decision. The retail sellers identified in the paragraphs and tables below must update the relevant sections of their draft RPS Plans in their final submittal.

8.3.1. Long-Term Procurement

Retail sellers must show that 65 percent of their procurement that is designated to meet their RPS requirement consists of contracts with term lengths

of 10 years or more.[148] To ensure compliance, the 2026 ACR explains that RPS Plans should demonstrate how retail sellers are satisfying this long-term procurement requirement.

According to our assessment of their Draft 2026 RPS Plans, the Commission finds that Clean Power Alliance, San Diego Community Power, and Shell Energy must provide additional information as shown in Table 1 below.

Table 1: **Long-Term Procurement**

Retail Seller	Commission Finding
Clean Power Alliance	On page 11 of its Draft 2026 RPS Plan, CPA states that 934 MW of long-term RPS resources are expected to come online between 2026 and 2028. However, on page 13, CPA states that it has 213 MW of long-term resources under contract that have yet to come online between 2026 and 2028. Further, CPA's Project Development Status Update template shows that it has 213 MW of RPS resources in development. CPA must clarify how many MW of long-term RPS resources it has online and how many MW are still in development and yet to come online.
San Diego Community Power	SDCP did not provide an assessment of current and long-term procurement progress that extends 10 years to 2036. The narrative and the long-term contracting chart provided in this section only describes procurement progress until 2030. According to the 2026 ACR, SDCP must provide an assessment of current and planned long-term procurement for all years through 2036.[149]
Shell Energy	The table and graphs in Figure 1 of Shell Energy's assessment of its long-term RPS position do not provide a quantitative assessment that extends 10 years to 2036. The table and graphs only present long-term procurement forecasts until 2030. According to the 2026 ACR, Shell

[148] Pub. Util. Code § 399.13(b)(2) and D. 17-06-026 OP 1 at 49.

[149] 2026 ACR at 14-15.

	Energy must update Figure 1 to provide an assessment of long-term procurement for all years through 2036.

8.3.2. Forecasting for Increased Transportation Electrification

Per the 2026 ACR, all retail sellers must address local transportation electrification adoption trends while planning for portfolio diversity and renewable resource procurement to meet incremental RPS requirements, consistent with D.18-05-026.[150] All retail sellers must demonstrate that transportation electrification is quantitively accounted for in their RPS procurement plans.

According to our review of their Draft 2026 RPS Plans, the Commission finds that San Diego Community Power is missing information regarding transportation electrification and must provide additional information as listed in Table 2 below.

Table 2: **Forecasting for Transportation Electrification**

Retail Seller	Commission Finding
San Diego Community Power	1. SDCP did not compare its transportation electrification forecast to the California Energy Commission's (CEC) IEPR

[150] D.18-05-026 at Ordering Paragraph 3 ("… all retail sellers … must annually demonstrate that transportation electrification is accounted for in their procurement plans by explicitly referencing forecasted transportation electrification in their Renewables Portfolio Standard procurement plans; providing a detailed description of the data and method used to support their forecast; and explaining how they considered the California Energy Commission's Integrated Energy Policy Report transportation electricity demand forecast in creating their own forecast"). See also D. 22-12-030 at 16-17.

Retail Seller	Commission Finding
	transportation electricity demand forecast. According to the 2026 ACR, SDCP must provide a comparison of its transportation electrification forecast to the CEC's IEPR transportation electricity demand forecast. It shall clearly identify which vintage year IEPR forecast it is referencing for its transportation electrification forecast. If it is not using the most up-to-date IEPR forecast, it shall provide reasoning for its choice of vintage year for the IEPR forecast. If it is not using or considering the IEPR transportation electricity demand forecast in creating its own transportation electrification forecast, it shall provide its reasoning.[151] 2. SDCP did not provide a table or chart showing its annual load from transportation electrification. According to the 2026 ACR, SDCP must provide a table and/or chart showing the annual load from transportation electrification as forecasted in its analysis. This graphic shall also compare its transportation electrification load results to the IEPR transportation electricity demand forecast results.[152]

[151] *See* 2026 ACR at 19.

[152] *See* 2026 ACR at 19.

8.3.3. Project Development Status Update and Template

Pub. Util. Code Section 399.13(a)(6)(D) requires retail sellers to include a status update of their project development schedule for all eligible renewable energy resources currently under contract in their RPS Plans. This information is important because it allows the Commission to monitor each retail seller's ability to meet RPS compliance obligations and report RPS capacity additions and new RPS contracts to the Legislature. In their Draft 2026 RPS Plans, most CCAs and ESPs include their respective PDSU spreadsheet, however some retail sellers have missing or inconsistent information.

Clean Power Alliance, San Diego Community Power, and Shell Energy must resolve inconsistencies related to Section V (Project Development Status Update) in their Final 2026 RPS Plans, as detailed in Table 3 below.

Table 3: **Project Development Status Update**

Retail Seller	Commission Finding
Clean Power Alliance	The Commercial Operation Dates (CODs) for the Eaves 1, Eaves 3, Southbay 6, Solar Star 3, and Solar Star 4 projects do not match between Table 6 at page 47, in the RPS Plan narrative, and the Project Development Status Update templates provided as an excel file and attached as an Appendix D to the Draft RPS Plan. CPA must clarify the discrepancies between these CODs.
San Diego Community Power	The project details on the PDSU template and the table in the PDSU section narrative do not match for some of the projects. First, the CODs for the Yellow Pine III and Pelican's Jaw Solar projects do not match between the PDSU template and the table in the narrative. Second, the contract term lengths for the IP Darden IV project do not match between the PDSU template and the table in the narrative. SDCP must clarify these project details.

Retail Seller	Commission Finding
Shell Energy	The Westland Grape project that is reported in Shell Energy's PDSU template is missing data in the following fields: zip code, coordinates for latitude and longitude, total contract volume, and transmission status (if applicable). Shell Energy must provide the missing data in its PDSU or explain why the data cannot be provided. The hybrid resource in development that Shell Energy discusses on page 33 of its PDSU narrative is missing the following project details: project/facility name, location, and length of contract. According to the ACR, for the RPS Plans narrative, retail sellers are required to provide project/facility name, technology type, capacity procured from the project, location (city and county), length of contract, and commercial online date for projects in development.[153] Shell Energy must provide the required data in its PDSU narrative.

8.3.4. Compliance Risk

Pub. Util. Code §399.13(a)(6)(F) provides that the renewable energy procurement plan shall include an assessment of the risk that an eligible renewable energy resource will not be built or that construction will be delayed, with the result that electricity will not be delivered as required by the contract. As described below, retail sellers shall discuss compliance risk, risk modeling and risk factors, and lessons learned in subsections to Section VII of their 2026 RPS Plans. With respect to compliance risk, each retail seller shall provide a written assessment of the risks to their RPS portfolio that could impact their ability to achieve RPS compliance requirements, including describing the severity of the individual risks (e.g., high, medium, low) they have identified.[154]

[153] *See* 2026 ACR at

[154] *See* 2026 ACR at 28-29.

The Commission finds that Redwood Coast Energy Authority did not assign any severity ratings to the individual compliance risks it identified. Per the 2026 ACR, Redwood Coast Energy Authority must correct the identified deficiency in its final 2026 RPS Plan.

8.3.5. Risk Modeling and Risk Factors

Per the 2026 ACR, retail sellers must provide details of the modeling and model(s) used (e.g., deterministic, stochastic) to conduct annual risk assessments of their entire RPS portfolio. These details should include specific inputs and assumptions regarding their risk assessment model. In addition, risk modeling should evaluate a range of risk factors, such as those described above regarding compliance delays and risks. The intent here is for retail sellers to provide sound and reasonable inferences based on both qualitative and quantitative modeling criteria.[155]

On page 70 of its Draft 2026 RPS Plan, Orange County Power Authority (OCPA) states that "If a counterparty was found to be unrated, then the contract was reviewed to identify specified credit assurances, which are diligently negotiated by OCPA during the contracting process." This statement appears to be a leftover sentence from its 2025 RPS plan where Orange County Power Authority explained how it investigates the credit ratings of potential counterparties to assess the risk that the counterparties are unable or unwilling to honor their RPS delivery obligations. While this explanation of how it considers credit ratings is deleted from Orange County Power Authority's draft 2026 RPS Plan, the sentence mentioned above on unrated counterparties remains in the current RPS plan narrative. Orange County Power Authority must clarify

[155] *See* 2026 ACR at 29.

and elaborate further on whether it still considers and investigates credit ratings when it assesses or considers counterparty risk. If it no longer considers credit ratings, it should delete this sentence.

8.3.6. Renewable Net Short Calculations

RNS calculations show the amount of new renewable generation capacity, including resources obtained through short term and long-term procurement, that must be built in California or delivered from out of state sources or both to meet RPS targets. In their draft RPS Plans, retail sellers are required to provide both a quantitative and narrative response showing how their risk assessments as described in Section VII of their 2026 RPS Plans have been incorporated into their 2026 RNS calculations.

Upon reviewing the Draft 2026 RPS Plans, the retail sellers listed below must address identified inconsistencies related to RNS Calculations in their RPS Plans, as detailed in Table 4.

Table 4: **Renewable Net Short Calculations**

Retail Seller	Commission Finding
Calpine Energy Solutions (CES)	CES' RNS template does not clearly show how its REC bank progresses as the REC bank totals in variables Ha, H, and J change over each forecast year. This leads to calculation errors appearing in these same variables for the years 2025, 2028, 2031, 2034 and for the CP 5, CP 6, CP 7, and CP 8 totals. CES must correct its RNS template by providing non-zero values, if applicable, for variables HB, HC, IA, and IB for all years (past, current, and forecast) in the RNS template. As an example, CES should provide non-zero values to variable HC in all years where the Annual Gross RPS Position exceeds the Net RPS Procurement Need and should provide non-zero values for variables Ia and IB where there are contemplated applications of REC bank to RPS

Retail Seller	Commission Finding
	Procurement Quantity Requirements and sales of excess RECs.
Clean Energy Alliance	1.The values for "Total Retail Sales (MWh)" for the years 2023 and 2024 in row A of the RNS template do not match the values for "Total Retail Sales (MWh)" in Table 1, row 26, of the Cost Quantification Template for the years 2023 and 2024. CEA must clarify or provide the correct values for Total Retail Sales for the years 2023 and 2024 in its Cost Quantification and RNS templates. 2. The narrative in this section twice claims that CEA has contracted with only one facility that has yet to achieve commercial operation.[156] This contradicts CEA's project development status update in Section V, where it states that it has three contracts that have yet to achieve commercial operation: the Cape Generating Station 1 project, the Deer Creek hybrid solar and storage project, and the Darden Clean Energy solar and storage project.[157] CEA must clarify its RPS Plan narrative to reflect the latest quantity of projects it has under development that have not achieved commercial operation yet and, if necessary, update its risk analyses and renewable net short calculations to reflect the latest project development status updates.
Clean Power Alliance	There are errors on the RNS template calculations where multiple values do not match between the RNS excel file and the RNS worksheets attached as Appendix C to both the public and confidential RPS

[156] Clean Energy Alliance Draft 2026 RPS Plan at 79 and 80.

[157] Clean Energy Alliance Draft 2026 RPS Plan at 59.

Retail Seller	Commission Finding
	Plans. List of cells where there are mismatching values are as follows: •H8, H9, H11, H25, H41 (Compliance Period 4) •L8, L9, L11, L25, L41 (Compliance Period 5) •P8, P9, P11, P25, P41 (Compliance Period 6) •T8, T9, T11, T25, T41 (Compliance Period 7) •X8, X9, X11, X25, X41 (Compliance Period 8) CPA must clarify or correct the mismatching values between the RNS excel file and the worksheets in attachment C of both the confidential and public RPS Plans.
King City Community Power	King City's RPS Plan narrative for this section does not provide insight into its RPS position for 2026 and subsequent years and compliance periods. The narrative for this section does not clearly describe King City's quantitative progress towards RPS requirements, as required by the 2026 ACR.[158] King City must provide a quantitative description of its progress towards RPS requirements for the current and future compliance periods.
Redwood Coast	The RNS templates that are attached as appendices to RCEA's public and confidential versions of its RPS Plan narrative are showing whole numbers (1 or 0) in the rows for variable Gb "Annual Gross RPS Position (%)" and variable Lb "Annual Net RPS Position after Bank Optimization (%)." These rows should show decimals to represent percentages and should not be rounded up or down to the nearest whole number. RCEA must correct the RNS templates attached to its RPS Plans narratives so that the rows for variable Gb "Annual

[158] *See* 2026 ACR at 30-31.

Retail Seller	Commission Finding
	Gross RPS Position (%)" and variable Lb "Annual Net RPS Position after Bank Optimization (%)" show decimals to represent percentages.

8.3.7. Minimum Margin of Procurement Level

According to the RPS requirements, retail sellers must define an MMoP in their RPS Plans to show how risk will be mitigated if renewable projects under contract are delayed or terminated, or projects do not perform as expected. Per the directives of the 2026 ACR, all retail sellers must define in their proposed 2026 RPS Plans an MMoP assumed above the minimum procurement level and explicitly report their MMoP levels in this subsection. The MMoP must be reflected in retail sellers' risk-adjusted RPS eligible procurement provided in the quantitative response in RPS Plan Section VIII: Renewable Net Short Calculations and must remain separate from retail sellers' voluntary margin of over-procurement (VMoP).[159]

In its Draft 2026 RPS Plan, Redwood Coast Energy Authority states that its forecasted total RPS eligible procurement exceeds its gross RPS Procurement Quantity Requirement (PQR) through CP 8.[160] However, its RNS calculations template shows that it has a renewable shortage starting in 2034 and is not meeting the RPS PQR through CP 8. Redwood Coast Energy Authority must clarify this statement to reconcile it with its RNS calculations.

[159] 2026 ACR at 32.

[160] Redwood Coast Energy Authority Draft 2026 RPS Plan at 52.

8.3.8. Minimum Margin of Procurement Methodology and Inputs

Per the directives of the 2026 ACR, Draft 2026 RPS Plans for all retail sellers must include both a narrative and quantitative description of their risk-adjusted portfolio methodology and inputs required to inform a retail seller's proposed MMoP.

Upon reviewing the Draft 2026 RPS Plans, the retail sellers listed below must address identified inconsistencies related to MMoP Methodology and Inputs, as detailed in Table 5.

Table 5: **Minimum Margin of Procurement Methodology and Inputs**

Retail Seller	Commission Finding
Clean Power Alliance (CPA)	The values for "Forecast Failure Rates for RPS Facilities in Development (%)" on the RNS template do not match the values for forecast failure rates for RPS Facilities in Development that are presented in Table 8 of the RPS Plans narrative.[161] It is unclear if these values are supposed to be the same failure rates or if there are two sets of different failure rates that represent two different risk analyses. CPA must clarify these different sets of failure rates.
Sonoma Clean Power Authority	In Figure 4 on page 54 of its RPS Plan, SCPA's "Forecasted RPS percentage" value for the year 2026 does not match what is reported on its RNS templates for the year 2026. SCPA must correct or clarify the difference in these values.

8.3.9. Consideration of Price Adjustment Mechanisms

Pursuant to Pub. Util. Code §399.13(a)(6)(E), each retail seller must describe how price adjustments (e.g., index to key components, index to Consumer Price Index, price adjustments based on exceeding transmission or

[161] Clean Power Alliance Draft 2026 RPS Plan at 59.

other cost caps) will be considered and potentially incorporated into contracts for RPS-eligible projects with online dates occurring more than 24 months after the contract execution date. Retail sellers should discuss how any potential price adjustments will maximize value for ratepayers and minimize potential risks to ratepayers.

In its Draft 2026 RPS Plan, Redwood Coast Energy Authority discusses price adjustments that are present in its existing contracts or are appearing in bids in its solicitations for long-term contracts. However, Redwood Coast does not discuss whether these price adjustments maximize value and/or reduce risks for ratepayers or not. RCEA must update its Plan to discuss if these observed trends in price adjustment mechanisms have the potential to maximize value and/or minimize potential risks to ratepayers.

8.3.10. Cost Quantification Template

Per the directives of the 2026 ACR, all retail sellers provide cost data on all procurement contracts for eligible renewable energy resources.

All retail sellers except for Calpine Power complied with this requirement. Table 3 (Procurement/Generation and Sales, MWh) of Calpine Power America's Cost Quantification template lists wind generation for 2025. However, there is no corresponding wind cost data for that year in Table 1 (Actual Net Costs, $).[162] Calpine Power America must provide the missing cost figure or an explanation for this omission in its Final 2026 RPS Plan.

[162] Calpine Power America Draft 2026 RPS Plan, Appendix C.

9. Procedural Matters

This decision affirms all rulings made by the ALJ and assigned Commissioner in this proceeding. This decision also considers several motions in Sections 9.1 through 9.3.

9.1. SCE's Motion to Update Draft 2026 RPS Plan

On July 27, 2026, SCE filed its *Motion of SCE (U 388 E) to Update its Draft 2026 RPS Plan and the Motion of SCE (U 388 E) for leave to file the Confidential Version of its Motion to Update Draft 2026 RPS Plan under Seal*. The motion to update Draft 2026 RPS Plan is submitted in compliance with the 2026 ACR and is granted.

9.2. Motion to File Confidential Comments

On July 13, 2026, Cal Advocates filed a motion for an order allowing it to file under seal the confidential version of the Cal Advocates' Comments on the Draft 2026 Renewables Portfolio Standard Procurement Plans (Cal Advocates' Comments – Confidential Version). Cal Advocates' Comments (Confidential Version) include multiple references to materials that PG&E and SDG&E claim confidential in their RPS Plans.

Cal Advocates notes that PG&E labeled such information as confidential pursuant to D.06-06-066 as modified by D.21-11-029 and the May 21, 2014 Administrative Law Judge's Ruling on Renewable Net Short filed in Rulemaking 11-05-005.[163] SDG&E labeled such information as confidential pursuant to D.06-06-066.[164] Cal Advocates states that its reliance on the materials that the PG&E

[163] Cal Advocates Motion, dated July 13, 2026, at 1 and Appendix A.

[164] Cal Advocates Motion, dated July 13, 2026, at 1 and Appendix B.

and SDG&E claim are confidential is necessary to support the arguments in Cal Advocates' Comments.[165]

On July 27, 2026, PG&E filed a motion for leave to file confidential information in PG&E's reply comments under seal. The material PG&E seeks to protect is the confidential, unredacted version of PG&E's Draft 2026 Renewables Portfolio Standard Procurement Plan Reply Comments (Reply Comments) and contains market sensitive information. Redacted material relates to PG&E's evaluation of short-term RPS transactions under the proposed Draft 2026 RPS Plan Confidential purchase and sales frameworks, and redactions are related to proposed confidential score sheets, analyses and evaluation for RPS contracts.[166]

Having reviewed the Cal Advocates' and PG&E's motions, and good cause being shown, the requests to file under seal the confidential versions of Cal Advocates' comments and PG&E's reply comments are granted.

9.3. Motions for Confidentiality — 2026 Draft RPS Plans

The motions for confidentiality of retail sellers named in Table 6 are partially approved. The Commission reviewed Draft 2026 RPS Plans to ensure retail sellers did not excessively redact information. This decision orders retail sellers identified in the table below to correct their excess redactions in their Final 2026 RPS Plans.

The underlying principle of confidentiality pursuant to the 2026 ACR and D.06-06-066, as modified by D.21-11-029, is about making information publicly accessible to the greatest extent possible while protecting certain market sensitive information. As such, the party seeking confidentiality protection for data in RPS

[165] Cal Advocates Motion, dated July 13, 2026, at 2.

[166] PG&E Motion, dated July 27, 2026, Attachment A.

Plans must make claims consistent with the confidentiality matrices in D.06-06-066, as modified by D.21-11-029. The party seeking confidentiality bears the burden of proof.

We find some retail sellers have excessively redacted the information, which is out of compliance with prior Commission guidance. The table below lists retail sellers for whom Commission review found unauthorized redactions. Final 2026 RPS Plans must be revised to comply with the guidance in D.06-06-066, as modified by D.21-11-029.

Table 6: **Confidentiality Redactions and Commission Findings**

Retail Seller	Commission Finding
SCE	SCE inappropriately redacts cells in the column for the year 2025 in its RNS template in Appendices C.1 and C.2. These cells contain information pertaining to past RPS Net Short Position and REC bank data. According to D.21-11-029, RPS Net Short Position data is confidential only for the current year / year of filing and the following two years. The May 21, 2014, ALJ Ruling on Renewable Net Short establishes that Optimized RNS data, which includes REC bank data, is confidential. Therefore, pursuant to the 21 May 2014 ALJ Ruling and D.21-11-029, Optimized RNS data, which includes REC Bank, must be confidential for all future years, but starting with the current year / year of filing of the RPS Plan. As such, SCE must remove the redactions for the year 2025.
SDG&E	1) In Appendix 1.c on its PDSU template, SDG&E redacts the Transmission Status for two projects. In its Motion to File Under Seal (MFUS), SDG&E seeks confidential treatment for this information under Category VII.G of the Matrix of Allowed Confidential Treatment of IOU Data. However,

Retail Seller	Commission Finding
	Category VII.G applies to score sheets, analyses, and evaluations of proposed RPS contracts and it is unclear how the redacted transmission-status information falls within Category VII.G. SDG&E must revise its MFUS to explain how Category VII.G applies and why the information warrants confidential treatment. 2) SDG&E's MFUS references its Info Only TOD Factors Workpapers as being in Appendix 3. However, in its draft RPS Plan the TOD Factors appear in Appendix 19. SDG&E must revise its MFUS to identify the correct appendix.
Central Coast Community Energy (3CE)	3CE must address the following errors in its MFUS: 1) 3CE redacts energy storage procurement information in Section XI.C on page 61 of its RPS Plan, but its MFUS does not identify or claim confidential treatment for that redaction. Further, the MFUS claims confidential treatment for Sections XI.D and XI.F, although Section XI.D contains no redactions and Section XI.F does not appear in the RPS Plan. 3CE must revise its MFUS to identify the correct Section and accurately reflect the redactions in its RPS Plan. 2) 3CE redacts information in Table 7 of Section XIII on page 64 of both its RPS Plan and the redlined plan. However, its MFUS requests confidential treatment for Table 5 of Section XIII. 3CE must revise its MFUS to identify Table 7 as the table for which it seeks confidential treatment.
Desert Community Energy (DCE)	In Table 1 of its Cost Quantification template in Appendix E, DCE inappropriately redacts row 26, "Total Retail Sales (MWh)," for the years 2023

Retail Seller	Commission Finding
	through 2025. As per D.21-11-029, load data may be treated as confidential only for the current year / year of filing and the following two years. Because the redacted data is outside that confidentiality period, DCE must remove the redactions.
Orange County Power Authority (OCPA)	In Table 1 of its Cost Quantification template in Appendix E, OCPA inappropriately redacts row 26, "Total Retail Sales (MWh)," for the years 2023 through 2025. As per D.21-11-029, load data may be treated as confidential only for the current year / year of filing and the following two years. Because the redacted data is outside that confidentiality period, OCPA must remove the redactions.
San Diego Community Power (SDCP)	1) In its MFUS, SDCP requests confidential treatment for column I of its RNS template in Appendix C, which contains energy forecast data for the year 2025. However, the confidentiality period for load and energy forecasts reported for RPS compliance and procurement covers only the current year / year of filing and the next two future years (2026-2028). SDCP must revise its MFUS to remove the confidentiality claim for column I and instead identify columns J through M and column P for confidential treatment. 2) In Table 2 of its Cost Quantification template in Appendix E, SDCP redacts row 58, "Total Incremental Rate Impact," but does not request confidential treatment for that information in its MFUS. SDCP must revise its MFUS to identify Row 58 for confidential treatment.
BP Energy	BP Energy inappropriately redacts the columns for 2029, 2030, 2031, and CP 7 in the table on page 10 in Section IV.A.1. In the redlined version of its RPS

Retail Seller	Commission Finding
	Plan, BP Energy also inappropriately redacts the 2025 column. As per D.21-11-029, RPS Net Short Position data is confidential only for the current year / year of filing and the next two following years. BP Energy must remove these redactions.
Calpine Power America-CA, LLC (CPA)	CPA inappropriately redacts cells in the columns for the years 2025, 2029, and 2030 in its RNS template in Appendix B. This information pertains to its past and forecast RPS Net Short Position data, including its REC bank. According to D.21-11-029, RPS Net Short Position data is confidential only for the current year / year of filing and the following two years. The May 21, 2014, ALJ Ruling on Renewable Net Short establishes that Optimized RNS data, which includes REC bank data, is confidential. Therefore, pursuant to the 21 May 2014 ALJ Ruling and D.21-11-029, Optimized RNS data, which includes REC Bank, must be confidential for all future years, but starting with the current year / year of filing of the RPS Plan. As such, RPS Net Short Position data that includes only Gross RPS Position data, up to Variable Gb, can only be claimed as confidential for the current year / year of filing and the next two future years. Optimized RNS data, from variables Ha to Lb, which includes REC bank info, can be claimed as confidential for all years in the future, but starting with the current year / year of filing of the RPS Plan. Therefore, CPA must remove all the redactions in the column for 2025. As for the columns for the years 2029 and 2030, CPA must remove the redactions to Variables A, C, E, Ga, and Gb.
Shell Energy Solutions (Shell Energy)	1) On page 8 of its RPS Plan, Shell Energy inappropriately redacts the capacity (MW) information from various RPS contracts in its long-

Retail Seller	Commission Finding
	term resources portfolio that are online. According to Appendix 2, ESP & CCA Matrix of Allowed Confidential Treatment, in Attachment 2 of D.21-11-029 on RPS confidentiality rules, contract summary information, which includes capacity, is public. In addition, an ESP and CCA contract becomes public 30 days after its commercial operation date (the date energy deliveries begin), or 18 months after contract execution, whichever comes first. Accordingly, Shell Energy must disclose the capacity (MW) amounts for the Coachella Hills, Palen Solar / Maverick 4 Solar, Maverick 7 Solar, Sandrini Solar, and SunZia projects described on page 8. 2) In column S of its PDSU template, Shell Energy redacts the Commercial Operation Date of the Westland Grape project. However, Shell Energy's MFUS does not request confidential treatment for this information. Shell Energy must either remove the redaction from column S of its PDSU template or revise its MFUS to properly request this redaction for confidential treatment.

10. Summary of Public Comment

Rule 1.18 of the Commission's Rules of Practice and Procedure (Rules) allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(a) requires that all written public comment submitted prior to the submission of the proceeding are part of the administrative record of the proceeding. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision

issued in that proceeding. There are no relevant public comments on the Docket Card of this proceeding.

11. Comments on Proposed Decision

The proposed decision of ALJ Nilgun Atamturk in this matter was mailed to the parties in accordance with Section 311 of the Pub. Util. Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _____, and reply comments were filed on _____ by _____.

12. Assignment of Proceeding

Christine Harada is the assigned Commissioner and Nilgun Atamturk and Darryl Gruen are the assigned Administrative Law Judges in this proceeding.

Findings of Fact

1. Three IOUs, three SMJUs, 25 CCAs, and 11 ESPs submitted Draft 2026 RPS Plans.
2. All but one retail seller is forecasted to meet the 65 percent long-term contract procurement requirement in the 2025-2027 compliance period (CP 5).
3. For 2025, before applying banked RECs toward RPS compliance, the utilities reported annual gross RPS positions equal to 38.3% of PG&E's load, 46.4% of SCE's load, and 81.2% of SDG&E's load.
4. PG&E's Draft 2026 RPS Plan contains the required elements in Table 1 of the 2026 ACR.
5. PG&E's Draft 2026 RPS Plan meets the requirements of the 2026 ACR.
6. PG&E has a sustained annual short RPS position through the forecast horizon, primarily resulting from the VAMO processes.
7. PG&E has historically relied on banked RECs.

8. D. 26-09-047 affirmed the Commission's methodology of valuing RECs generated prior to January 1, 2019, and banked, but used for IOU customer compliance in later years at zero dollars when calculating the PCIA.

9. A combination of banked credits, new purchases, and portfolio sales will help PG&E meet its compliance obligations.

10. PG&E's portfolio management strategy provides PG&E flexibility to manage RPS compliance, portfolio needs, and procurement risks under future conditions.

11. Allowing both short-term and longer-term transactions may help PG&E mitigate project delays, changing load forecasts while supporting bundled customer affordability.

12. Pursuing contract amendments related to but not limited to contract price reductions, extension of contract terms, increased buyer curtailment flexibility, and repowering of existing facilities and/or upgrades of existing facility equipment, contract terminations, existing facility and equipment upgrades, or a combination of these amendments may provide value to PG&E's customers.

13. Bilateral negotiations may allow PG&E to help fill specific gaps in PG&E's portfolio, e.g., particular delivery shape, that may not be available in solicitations, and may yield favorable prices to benefit ratepayers.

14. Participating in other market participants' or third-party competitive solicitations may maximize value for PG&E's customers.

15. Being able to transact via brokers and exchanges may help support a level playing field and permit PG&E to access potentially more cost-effective products.

16. The ability to retire RECs for LCFS credits will provide flexibility and demonstrate that PG&E is utilizing zero carbon intensity electricity for EV related charging.

17. Authority to sell short-term RPS products from its retained bundled share of its voluntary allocation at a price indexed to the applicable final PCC 1 MPB will allow PG&E to manage its RPS portfolio while reducing bundled customer cost exposure and avoiding volume uncertainty for load serving entities and other parties participating in the VAMO process.

18. SCE's Updated Draft 2026 RPS Plan contains the required elements in Table 1 of the 2026 ACR.

19. SCE's updated Draft 2026 RPS Plan meets the requirements of the 2026 ACR.

20. SCE forecasts a need for RPS-eligible resources to meet compliance requirements through CP 7 (2031-2033).

21. The key factors affecting RPS needs include increased transportation and electrification, departed load migration to and from CCAs, and macroeconomic factors.

22. SCE needs flexibility to procure new and existing resources through CP 7 to ensure continued compliance with RPS requirements.

23. PCC 1, PCC 2, and PCC 3 RECs sales and purchases may provide SCE flexibility to continue to meet its RPS targets in the most affordable way.

24. SCE submitted changes to its procurement protocols for new resources and existing resources, REC transaction protocols, and LCBF evaluation criteria.

25. SCE submitted changes to the 2025 Pro Forma Renewable PPA, Pro Forma PCC 1 REC Agreement, and Pro Forma PCC 3 REC Agreement to harmonize language among different versions or implement minor changes.

26. Customer participation in SCE's LCFS funded programs is expected to increase over time as EV adoption increases and SCE's program operations mature.

27. The informational TOD heat maps are no longer fulfilling the intent behind their requirement and their continued inclusion in the RPS Plan is unnecessary.

28. The Green Access Programs ceased to operate on an ongoing basis.

29. There is little or no value in continuing to track these programs through the annual RPS Plans.

30. SDG&E's Draft 2026 RPS Plan contains the required elements of the 2026 ACR.

31. There are deficiencies in SDG&E's Draft 2026 RPS Plan, as identified in Section 6.3.6 of this decision.

32. SDG&E anticipates that its RPS position will fall short beginning in the current compliance period.

33. Using its bank, and/or procuring new and existing RPS resources during CP 5 will help SDG&E meet its compliance requirements for CP 5 and beyond.

34. Selling and buying RPS not allocated to VAMO process and not used for RPS compliance may provide customer benefits while maintaining RPS compliance.

35. Having flexibility to manage its RPS portfolio by conducting short-term REC sales, and both short term and long term RPS procurement in the same year would enable SDG&E to meet compliance obligations, respond to increasing market competition, adapt to changing market conditions, and pursue the most economic options for its bundled customers.

36. Allowing SDG&E to procure or sell renewable energy products through participating in RFOs and using brokers and exchanges may provide SDG&E flexibility in meeting its RPS obligations.

37. D.26-07-008 reaffirmed requirements for Resource Adequacy (RA) contracts, specifically for Reliability Capacity (RC) and Imbalance Reserve (IR) products, which were originally established in D.05-10-042.

38. The three SMJUs (BVES, PacifiCorp, and Liberty, collectively) need to procure more RPS eligible renewables beginning in 2026 to meet their respective RPS requirements.

39. BVES' Draft 2026 RPS Plan contains the required elements of the 2026 ACR.

40. Liberty's Draft 2026 RPS Plan contains the required elements of the 2026 ACR.

41. PacifiCorp's Draft 2026 RPS Plan contains the required elements of the 2026 ACR.

42. Based on the CCAs' RNS reporting, collectively, CCAs are expected to need additional RPS procurement beginning in 2029.

43. The ESPs will collectively need additional procurement to meet RPS obligations beginning in 2026.

44. There are noted deficiencies in the CCAs' and ESPs' Draft 2026 RPS Plans regarding the following sections: Long-Term Procurement, Forecasting for Increased Transportation Electrification, Project Development Status Update & Template, Compliance Risk, Risk Modeling and Risk Factors, Renewable Net Short Calculations, MMoP Level, MMoP Methodology and Inputs, Consideration of Price Adjustment Mechanisms, and Cost Quantification Template.

45. SCE's Motion to update its Draft 2026 RPS Plan is submitted in compliance with 2026 ACR.

46. Cal Advocates' motion to file its comments under seal, dated July 13, 2026, is reasonable since Cal Advocates' Comments include multiple references to materials that are confidential.

47. PG&E's July 27, 2026, reply to Cal Advocates Comments contains market sensitive information.

48. Retail sellers identified in Section 9.4 of this decision have excessively redacted information in their Draft 2026 RPS Plans.

Conclusions of Law

1. PG&E's Draft 2026 RPS Plan should be approved.

2. PG&E's request for authority to procure long-term, intermediate-term, and short-term RPS products should be approved.

3. PG&E should be authorized to optimize its existing portfolio of RPS eligible contracts by renegotiating these contracts.

4. PG&E's request for authority to transact RPS products through bilateral negotiations should be approved.

5. PG&E's request for authority to participate in third-party competitive solicitations should be approved.

6. PG&E should be authorized to conduct RPS transactions through brokers and exchanges.

7. PG&E should be authorized to retire RECs for LCFS credits.

8. PG&E should be authorized to sell short-term RPS products from its retained bundled share of its voluntary allocation at a price indexed to the applicable final PCC 1 Market Price Benchmark.

9. SCE's Updated Draft 2026 RPS Plan should be approved.

10. SCE's request for authority to procure additional RPS eligible new and existing resources should be approved.

11. SCE's request to purchase and sell PCC 1, PCC 2, and PCC 3 RECs should be approved.

12. SCE's procurement protocols for new resources and existing resources, REC transaction protocols, and LCBF evaluation methodology should be approved.

13. SCE's Pro Forma Renewable PPA, Pro Forma PCC 1 REC Agreement, and Pro Forma PCC 3 REC Agreement should be approved.

14. SCE should be allowed to claim incremental LCFS credits through the retirement of RECs.

15. PG&E, SCE, and SDG&E should be allowed to discontinue including informational TOD heat maps in future RPS Plans.

16. SCE and SDG&E should be allowed to discontinue reporting on GTSR programs in RPS Plans.

17. PG&E should continue reporting on its GTSR program in RPS Plans until it ceases using a borrowed pool of RPS resources for its GTSR needs.

18. SDG&E's Draft 2026 RPS Plan should be approved with modifications.

19. SDG&E's request for the authority to use banked RECs should be approved, subject to the condition that it exhaust RECs banked after 2018 before using pre 2019 banked RECs, as directed by OP 18 of D.25-12-025.

20. SDG&E's request for authority to conduct optional bundled or unbundled RECs purchases from new or existing resources, either through short-term or long-term contracts, should be approved.

21. SDG&E's request for authority to sell RPS volumes should be approved.

22. SDG&E's request for authority to procure or sell renewable energy products through participating in RFOs and using brokers and exchanges should be approved.

23. SDG&E's request to buy and sell RECs in the same year should be approved.

24. SDG&E should address in its Final 2026 RPS Plan the deficiencies listed in Section 6.3.6 of this decision.

25. The IOUs should continue to submit a Tier 3 Advice Letter for approval of long-term transactions and a Tier 1 Advice Letter for short-term transactions that are conducted in accordance with the transaction framework approved in their RPS Plans.

26. The alignment of future RPS contracts with the policy determinations and requirements of D.26-07-008 should be addressed in the next RPS planning cycle.

27. The Draft 2026 RPS Plan filed by BVES should be approved and deemed final.

28. The Draft 2026 RPS Plan filed by Liberty should be approved and deemed final.

29. The Draft 2026 RPS Plan filed by PacifiCorp should be approved and deemed final.

30. The CCAs and ESPs identified in this decision should correct the relevant section of their plans in their Final 2026 RPS Plans.

31. Clean Power Alliance of Southern California should update Long-Term Procurement, Project Development Status Update, RNS Calculations, MMoP Methodology and Inputs section of its Draft 2026 RPS Plan.

32. San Diego Community Power should update Long-Term Procurement, Forecasting for Increased Transportation Electrification, Project Development Status Update section of its Draft 2026 RPS Plan.

33. Shell Energy Solutions should update Long-Term Procurement, Project Development Status Update sections of its Draft 2026 RPS Plan.

34. Redwood Coast Energy Authority should update Compliance Risk, RNS calculations, MMoP Level, Consideration of Price Adjustment Mechanism section of its Draft 2026 RPS Plan.

35. Orange County Power Authority should update Risk Modeling and Risk Factors of its Draft 2026 RPS Plan.

36. Calpine Energy Solutions, LLC should update RNS Calculations section of its Draft 2026 RPS Plan.

37. Clean Energy Alliance should update RNS Calculations of its Draft 2026 RPS Plan.

38. King City Community Power should update RNS Calculations of its Draft 2026 RPS Plan.

39. Sonoma Clean Power Authority should update MMoP Methodology and Inputs section of its Draft 2026 RPS Plan.

40. Calpine Power America-CA, LLC should update its Cost Quantification Template of its Draft 2026 RPS Plan.

41. SCE's motion to update its Draft 2026 RPS Plans should be granted.

42. The motion of Cal Advocates for an order allowing it to file under seal the confidential version of Cal Advocates' Comments, dated July 13, 2026, should be granted.

43. The motion of PG&E for an order allowing it to file under seal the confidential version of PG&E's reply comments, dated July 27, 2026, should be granted.

44. Retail sellers as identified in Table 6 should un-redact non-confidential material in their Final 2026 RPS Plans to comply with guidance in D.06-06-066, as modified by D.21-11-029.

45. This proceeding should remain open.

O R D E R

IT IS ORDERED that:

1. Pursuant to the authority provided in Public Utilities Code Section 399.13(a)(1), the Draft 2026 Renewables Portfolio Standard Procurement Plan filed by Pacific Gas and Electric Company is accepted and deemed final.

2. Pursuant to the authority provided in Public Utilities Code Section 399.13(a)(1), the Draft 2026 Renewables Portfolio Standard Procurement Plans filed by Southern California Edison Company and San Diego Gas & Electric Company are accepted, as modified herein.

3. Southern California Edison Company and San Diego Gas & Electric Company must file a clean version and a redlined copy of their Final Renewables Portfolio Standard Procurement Plans as a compliance filing in this proceeding within 30 days of the issuance date of this decision.

4. Pacific Gas and Electric Company's request for authority to transact short-term, intermediate-term, and long-term Renewables Portfolio Standard (RPS) eligible resources is approved to the extent the procurement is either needed to meet RPS needs or to comply with California Public Utilities Commission's procurement-related orders issued in the Integrated Resource Planning proceeding.

5. Pacific Gas and Electric Company is authorized to renegotiate the contracts in its Renewables Portfolio Standard portfolio.

6. Pacific Gas and Electric Company's request to participate in third-party competitive solicitations is approved.

7. Pacific Gas and Electric Company's request to transact Renewables Portfolio Standard eligible products via brokers and exchanges is approved

8. Pacific Gas and Electric Company is authorized to retire renewable energy credits for the Low Carbon Fuel Standard credits.

9. PG&E's request for authority to sell short-term RPS products from its retained bundled share of its voluntary allocation at a price indexed to the applicable final PCC 1 Market Price Benchmark is approved.

10. Southern California Edison Company is authorized to procure additional Renewables Portfolio Standard (RPS) eligible resources to the extent the procurement is either needed to meet RPS needs or to comply with California Public Utilities Commission's procurement-related orders issued in the Integrated Resource Planning proceeding.

11. Southern California Edison Company is authorized to purchase and sell short-term and long-term portfolio content category (PCC) 1, PCC 2, and PCC 3 renewable energy credits.

12. Southern California Edison Company is authorized to use solicitations, other market participants' solicitations, bilateral contracts, brokers, and exchanges to procure renewable energy credits.

13. Southern California Edison Company's procurement protocols for new and existing resources, Renewable Energy Credits transaction protocols, and least-cost best-fit evaluation methodology are approved.

14. Southern California Edison Company's revised pro forma agreements are approved.

15. Southern California Edison Company is authorized to retire renewable energy credits for the Low Carbon Fuel Standard funded programs.

16. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are authorized to discontinue providing the informational TOD heatmaps in their RPS Plans.

17. Southern California Edison Company and San Diego Gas & Electric Company are authorized to discontinue reporting on GTSR programs in their RPS Plans. Pacific Gas and Electric Company must continue reporting on its GTSR program until it ceases using a borrowed pool of RPS resources for its GTSR needs.

18. San Diego Gas & Electric Company is authorized to use banked renewable energy credits consistent with excess procurement rules to meet its Renewables Portfolio Standard compliance requirements, subject to the condition that it exhaust RECs banked after 2018 before using pre-2019 banked RECs, as directed by D.25-12-025.

19. San Diego Gas & Electric Company's request to conduct optional bundled renewable energy plus RECs and/or unbundled RECs purchases from new or existing resources, either through short-term or long-term contracts is approved to the extent the procurement is either needed to meet Renewables Portfolio Standard needs or to comply with the California Public Utilities Commission's procurement-related orders issued in the Integrated Resource Planning proceeding.

20. San Diego Gas & Electric Company's request to procure renewable energy credits for compliance through solicitations, bilateral agreements, or brokers and exchanges is approved.

21. San Diego Gas & Electric Company's request for authorization to sell Renewables Portfolio Standard eligible products is approved.

22. San Diego Gas & Electric Company's request to buy and sell renewable energy credits in the same year is approved.

23. San Diego Gas & Electric Company shall address the deficiencies listed in Section 6.3.6 of this decision in its Final 2026 Renewables Portfolio Standard Plan.

24. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company may issue solicitations to procure and/or sell Renewables Portfolio Standard (RPS) volumes in accordance with the directives of this decision within 10 days of filing their Final 2026 RPS Procurement Plans, unless their Final 2026 RPS Procurement Plans are suspended by the Energy Division Director within the 10-day period following the filings.

25. Pursuant to the authority provided in Public Utilities Code Section 399.13(a)(1), the Draft 2026 Renewables Portfolio Standard Procurement Plan filed by Bear Valley Electric Service, Inc. is accepted and deemed final.

26. Pursuant to the authority provided in Public Utilities Code Section 399.13(a)(1), the Draft 2026 Renewables Portfolio Standard Procurement Plan filed by Liberty Utilities (CalPeco Electric), LLC is accepted and deemed final.

27. Pursuant to the authority provided in Public Utilities Code Section 399.13(a)(1), the Draft 2026 Renewables Portfolio Standard Procurement Plan (2026 Off-Year Supplement to its 2025 Integrated Resource Plan Update) filed by PacifiCorp d/b/a Pacific Power is accepted and deemed final.

28. Clean Energy Alliance must file its Final 2026 Renewables Portfolio Standard Procurement Plan to address the findings concerning the Renewable Net Short Calculations section, as outlined in Section 8.3.6 of this decision.

29. Clean Power Alliance of Southern California must file its Final 2026 Renewables Portfolio Standard Procurement Plan to address the findings concerning the Long-Term Procurement, Project Development Status Update and Template, Renewable Net Short Calculations, and Minimum Margin of

Procurement Methodology and Inputs sections, as outlined in Sections 8.3.1, 8.3.3, 8.3.6, and 8.3.8 of this decision.

30. King City Community Power must file its Final 2026 Renewables Portfolio Standard Procurement Plan to address the findings concerning the Renewable Net Short Calculations section, as outlined in Sections 8.3.6 of this decision.

31. Orange County Power Authority must file its Final 2026 Renewables Portfolio Standard Procurement Plan to address the findings concerning the Risk Modeling and Risk Factors section, as outlined in Sections 8.3.5 of this decision.

32. Redwood Coast Energy Authority must file its Final 2026 Renewables Portfolio Standard Procurement Plan to address the findings concerning the Compliance Risk, Renewable Net Short Calculations, MMoP Level, and Consideration of Price Adjustment Mechanisms sections, as outlined in Sections 8.3.4, 8.3.6, 8.3.7, and 8.3.9 of this decision.

33. San Diego Community Power must file its Final 2026 Renewables Portfolio Standard Procurement Plan to address the findings concerning the Long-Term Procurement, Forecasting for Increased Transportation Electrification, and Project Development Status Update and Template sections, as outlined in Sections 8.3.1, 8.3.2, and 8.3.3 of this decision.

34. Sonoma Clean Power Authority must file its Final 2026 Renewables Portfolio Standard Procurement Plan to address the findings regarding the Minimum Margin of Procurement Methodology and Inputs section, as outlined in Section 8.3.8 of this decision.

35. Calpine Energy Solutions, LLC must file its Final 2026 Renewables Portfolio Standard Procurement Plan to address the findings concerning the Renewable Net Short Calculations section, as outlined in Sections 8.3.6 of this decision.

36. Calpine Power America-CA, LLC (dba Champion Energy Services, LLC) must file its Final 2026 Renewables Portfolio Standard Procurement Plan to address the findings concerning the Cost Quantification Template section, as outlined in Section 8.3.10 of this decision.

37. Shell Energy Solutions (Shell Energy North America (US), L.P.) must file its Final 2026 Renewables Portfolio Standard Procurement Plan to address the findings concerning the Long-Term Procurement, and Project Development Status Update and Template sections, as outlined in Sections 8.3.1 and 8.3.3 of this decision.

38. Pursuant to Public Utilities Code Section 365.1(c)(1), the Draft 2026 Renewables Portfolio Standard (RPS) Procurement Plans filed by the following Community Choice Aggregators are accepted and deemed final: Apple Valley Choice Energy; Ava Community Energy; Central Coast Community Energy; City of Palmdale; City of Pomona; City of Santa Barbara; City of San Jacinto dba San Jacinto Power; CleanPowerSF; Desert Community Energy; Lancaster Choice Energy; Marin Clean Energy; Pico Rivera Innovative Municipal Energy; Pioneer Community Energy; Rancho Mirage Energy Authority; San Jacinto Power; San Jose Clean Energy; Silicon Valley Clean Energy; Valley Clean Energy Alliance, and Westlight Energy (d/b/a Peninsula Clean Energy Authority). All other Community Choice Aggregators listed in the Summary section of this decision must file their Final 2026 RPS Procurement Plans as a compliance filing in this proceeding within 30 days of the issuance date of this decision.

39. Pursuant to Public Utilities Code Section 365.1(c)(1), the Draft 2026 Renewables Portfolio Standard (RPS) Procurement Plans filed by the following Electric Service Providers (ESP) are accepted and deemed final: 3 Phases Renewables, Inc.; BP Energy Retail Company California LLC; Commercial

Energy of Montana, Inc.; Constellation NewEnergy, Inc.; Direct Energy Business, LLC; Pilot Power Group, LLC; The Regents of the University of California; and Volt Energy, LLC. All other ESPs listed in the Summary section of this decision must file their Final 2026 RPS Procurement Plans as a compliance filing in this proceeding within 30 days of the issuance date of this decision.

40. Any Draft 2026 Renewables Portfolio Standard Plan that does not require a correction or clarification is deemed as final.

41. The motion to update Draft 2026 Renewables Portfolio Standard Procurement Plans and file them under seal, filed by Southern California Edison Company, dated July 27, 2026, is granted.

42. The motions seeking confidentiality filed by the retail sellers are granted, in part. As noted in Table 6 — Confidentiality Redactions and Commission Findings in Section 9.3 of this decision, these retail sellers must each remove the excess redactions in their Final 2026 Renewables Portfolio Standard (RPS) Procurement Plans within 30 days of the issuance date of this decision.

43. All rulings by the assigned Commissioner and the assigned Administrative Law Judge are affirmed.

44. All motions not otherwise ruled on are deemed denied.

45. Rulemaking 24-01-017 remains open.

This order is effective today.

Dated _____, at San Francisco, California