
TEHACHAPI PASS, KERN COUNTY

2025 PADILLA REPORT

Costs and Cost Savings for the RPS Program (Public Utilities Code § 913.3)

PUBLISHED JUNE 2025

California Public Utilities Commission

About this Report

The purpose of this annual Report is to comply with Public Utilities Code § 913.3. Each May 1, the California Public Utilities Commission is required to report to the Legislature the aggregated costs and cost savings of renewable energy expenditures and contracts for the previous year.

A digital copy of this report can be found at:

https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/energy-reports-and-whitepapers/rps-reports-and-data

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Cover Photo: Tehachapi Pass Wind Farm, Kern County, CA

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1. Executive Summary

The California Public Utilities Commission (CPUC) issues the 2025 Padilla Report: Costs and Cost Savings for the RPS Program pursuant to California Public Utilities Code § 913.3.[1] This report (referred to as the Padilla Report) summarizes 2024 Renewables Portfolio Standard (RPS) program procurement expenditure and contract price data for California's retail sellers. The 2025 Padilla Report provides a detailed summary of the expenditures of all RPS procurement contracts, including unbundled renewable energy credits for 2024 procurement as well as comparisons of RPS expenditures. The Padilla Report also includes historical expenditure and contract price data.

Two other CPUC reports provide related but different insights into the RPS program and utility costs:

- For information on the progress of the State's electricity retail sellers in meeting the RPS program requirements see the *RPS Annual Report to the Legislature*.[2]
- For information on all utility programs and activities currently recovered in retail rates, see the annual *California Electric and Gas Utility Costs Report: AB 67 Annual Report to the Governor and Legislature*, pursuant to California Public Utilities Code § 913.[3]

Key Conclusions

- *Increased RPS procurement costs:* In 2024, total RPS procurement generation expenditures spent to meet RPS requirements increased six percent over 2023, which was primarily driven by retail sellers increasing their procurement to meet the escalating RPS requirements.
- *Increased per-kilowatt-hour (kWh) cost of RPS procurement:* The investor-owned utilities' (IOUs') 2024 weighted average RPS portfolio cost per kWh increased by three percent.[4] For the Community Choice Aggregators (CCAs) and Electric Service Providers (ESPs), the 2024 weighted average per-kWh price of fixed-cost contracts increased by 2.4 percent and 33.0 percent, respectively, over 2023. The IOUs' increase is a reversal of the decreasing trend we have been observing over the last seven years of the RPS program. The trend of declining weighted average RPS generation costs may return in future years as more expensive legacy contracts expire, and relatively lower priced contracts become a larger portion of the RPS portfolio mix. Because contract prices reflect conditions at the time they were signed rather than when they begin delivering energy, their cost impacts are delayed to the year when

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[1] The full text of California Public Utilities Code (*hereinafter* Pub. Util. Code) § 913.3 can be found in Appendix D.

[2] See CPUC RPS Reports page: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/energy-reports-and-whitepapers/rps-reports-and-data.

[3] See CPUC *AB 67 Annual Cost Report* available at https://www.cpuc.ca.gov/ab67report.

[4] All values in this report have been adjusted for inflation using the U.S. Bureau of Labor Statistics' Producer Price Index (PPI) for the Electric Power Generation, Transmission, and Distribution Industry. This PPI was chosen as an effective method for capturing price movement specific to a given industry prior to retail level price changes.

the project achieves commercial operation and joins the RPS generation portfolio mix. This trend pertains only to the large IOUs, which have been in operation longer and include such legacy contracts within their portfolios.

- *RPS generation costs in context:* RPS procurement generation expenditures continue to contribute a substantial portion of IOUs' total generation costs. RPS generation costs represented 58.4 percent of the IOUs' generation costs in 2024, while RPS resources were 49.2 percent of overall IOU generation mix. This represents an increase from 52.7 percent of IOU generation costs in 2023, when RPS resources were 47.3 percent of the IOUs' generation mix. In 2024, RPS generation expenditures as a percentage of total generation cost were significantly larger than that of non-RPS generation. This result was due to the increased price and volume of RPS procurement and decrease in non-RPS costs in 2024 relative to 2023.

- *2024 conditions appear to have led to an increase in RPS prices:* The average price of RPS contracts executed in 2024 was 8.1 ¢/kWh, compared to the 5.9 ¢/kWh average price for contracts executed in 2023 in real dollars. This 37 percent increase was likely driven by an increase in demand due to retail sellers' need to meet end of RPS Compliance Period 2021-2024 requirements, uncertainty of supply chain constraints, anticipation of potential continuing increase in the overall levels of inflation, and higher interest rates. Additionally, overall demand for energy continues to grow with new end-users such as data centers and electric vehicle adoption, which may be leading to an increase in the overall amount of required RPS procurement.

- *Benefits of long-term, fixed-price renewable contracts:* While federal policy regarding renewable energy is causing uncertainty in the renewables market in 2025, which may further increase prices, the impact will be tempered by the large amount of long-term, fixed-price renewable energy contracting California has already completed. This effect is one of the original purposes of the RPS program, which was to be a cost-effective physical hedge against high and volatile prices.

2. Background

Senate Bill (SB) 836 (Padilla, 2011) requires the California Public Utilities Commission (CPUC) to report on the Renewables Portfolio Standard (RPS) program to the Legislature regarding "the costs of all electricity procurement contracts for eligible renewable energy resources, including unbundled renewable energy credits, and all costs for utility-owned generation approved by the CPUC."[5]

The California RPS program was established in 2002 by SB 1078 (Sher, 2002) with the initial requirement that 20 percent of electricity retail sales must be served by renewable resources by 2017. The program was accelerated in 2006 under SB 107 (Simitian, 2006), which required that the 20 percent mandate be met by 2010. In April 2011, SB 2 (1X) (Simitian, 2011) codified a 33 percent RPS requirement to be achieved by 2020. In 2015, SB 350 (de León, 2015) mandated a 50 percent RPS by December 31, 2030. On September 10, 2018, SB 100 (de León, 2018) was signed into law, which accelerated and further increased the RPS requirement to 60 percent by December 31, 2030, with interim targets of 44 percent by December 31, 2024, and 52 percent by December 31, 2027, and sets the goal that 100 percent of the state's retail electricity sales be met with renewable energy and zero carbon resources by 2045.[6]

The 2024 RPS procurement cost figures in this report were compiled from CPUC jurisdictional retail sellers: Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E); 3 small multi-jurisdictional utilities (SMJUs); 25 CCAs; and 11 ESPs.[7]

The annual procurement costs for generation in this report may not correspond precisely with the retail sellers' RPS compliance cost for the same year because the Renewable Energy Credits (RECs) associated with generation can be applied in later years for RPS program compliance purposes. Thus, the cost of procuring renewable energy might occur in one year and the RECs associated with generation may be applied for compliance in a later year.[8]

Retail sellers employ a variety of RPS procurement practices that lead to preferences for different types of RPS contracts, as shown in Table 1. Different RPS contract types include different products and therefore offer different cost profiles and risk management values to retail sellers. The annual expenditures for the large

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[5] Pub. Util. Code § 913.3(a). SB 697 (Hertzberg, 2015) changed the numbering of the Pub. Util. Code sections, and specifically changed § 910 to Pub. Util. Code § 913.3. None of the original reporting requirements that were required under Pub. Util. § 910 were modified by SB 697. SB 1222 (Hertzberg, 2016) modified the reporting date for this report among other minor changes.

[6] See the CPUC's RPS website for more information about RPS program requirements and legislative history: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps.

[7] See Appendix F for a list of California's Active Load Serving Entities.

[8] See CPUC Decision (D.)12-06-038; D.17-06-026.

IOUs may not be directly comparable to the SMJUs, CCAs, and ESPs because their approach to procurement, contracting, and risk management differs from the IOU CPUC jurisdictional retail sellers. That is, the large IOUs procurement contracts primarily have an "all-in" price that includes procurement of energy, capacity, and RECs and curtailment expenditure terms. "All-in" priced contracts are often considered fixed price because they feature one payment, in $ per MWh, which pays for all the products – energy, capacity, and RECs – subject to various contract terms related to availability, curtailment, etc. IOUs are allowed to procure via other contract types that are not "all-in", subject to statute and Commission limitations. This is different than the SMJUs, which may procure some "all-in" products, but are allowed to entirely procure unbundled RECs to meet their RPS requirements. By comparison, the CCAs often have RPS contract portfolios that include a significant portion of contracts for energy and RECs and/or are priced in the manner of "Index + REC."[9] These contracts are distinguished in that payment is based on an Index (e.g. CAISO day ahead price) and contracts do not include capacity value (even if there is capacity value associated with the generator, that value can be sold separately). Finally, ESPs traditionally have procured almost exclusively short-term contracts with Index + REC pricing. Compliance Period 2021-2024 was the beginning of the 65 percent RPS long-term procurement requirement and thus we observed a decline in short-term contracting by the CCAs and ESPs which should reduce potential cost volatility for their customers by transitioning towards more long-term contracts.[10]

RPS contract types determine which products (value streams) the retail seller is buying and thus the prices of the contract types are not easily comparable. Additionally, the RPS contract terms determine whether the offtaker or the generator determines the CAISO market bidding strategy and whether resulting market revenues flow to the offtaker or the generator. In summary, Table 1 below which includes the type of contracts that are often used by a given type of retail seller.

Table 1: Types of RPS Contracts

Type of Contract	Procured Products	Typical Retail Seller Preference
"All in" Long-term, Fixed-Price	Energy, Capacity, and RECs	Large IOU
REC-only	Unbundled RECs	SMJU
Index +REC	Energy and RECs	CCA and ESP

[9] Index + REC contracts generally define "Index" energy as the CAISO Integrated Forward Market Day Ahead Price for CAISO SP-15 or NP-15 when the energy is delivered.

[10] SB 350 (de León, 2015) required that 65 percent of RPS procurement be derived from long-term contracts (10 years or more). Prior to SB 350 the requirement was 0.25 percent.

3. Renewables Program Costs

This section addresses the costs associated with renewable resource procurement in 2024, consistent with the requirements of § 913.3(a)(1)-(2) and (b).

The 2024 costs and cost savings discussed in this section include:

- RPS Procurement Expenditures by retail seller type
- Comparison of RPS Procurement Expenditures with Revenue Requirements (for IOUs only)

A. RPS Procurement Expenditures

The 2024 RPS expenditures are the costs paid in 2024 pursuant to the cumulative portfolio of delivering RPS contracts with operating RPS-eligible facilities. For a detailed report on all electric utility costs, including all electricity procurement, see the CPUC *California Electric and Gas Utility Costs Report: AB 67 Annual Report to the Governor and Legislature* pursuant to California Public Utilities Code §913.[11]

To compare annual changes in RPS procurement expenditures and all categories of retail sellers, this section provides information not only on the 2024 total RPS procurement expenditures but also the expenditures as weighted averages in cents per kWh.

As shown in the below sections, the total real-dollar RPS expenditures[12] for retail sellers increased and there was also a rise in 2024 RPS expenditures on a cents per kWh basis. However, for the reasons explained below, the overall downward trend of weighted average expenditures that began 10 years ago is expected to continue over the longer-term[13,14]

This section details 2024 RPS expenditures by retail seller type. In 2024, retail sellers experienced slight variations from the overall trends described above, primarily due to their differing procurement approaches

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[11] See CPUC *AB 67 Annual Cost Report* available at https://www.cpuc.ca.gov/ab67report

[12] Procurement Expenditures for 2024 include costs for all procurement from online RPS-eligible facilities that generated electricity in 2024. Large IOU procurement expenditures include payments for curtailment volumes which generally increases the unit price of energy reported. See California ISO's Managing Oversupply page for more information on curtailment: http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.

[13] See also Lazard, Levelized Cost of Energy Analysis – Version 17.0 (June 2024) at 13: "The cost-competitiveness of renewables will lead to the continued displacement of conventional generation and an evolving energy mix—the timing of such displacement and composition of such mix will be impacted by many factors, including those outside of the scope of our LCOE (e.g., grid investment, permitting reform, transmission queue reform, economic policy, continued advancement of flexible load and locally sited generation, etc.)."

[14] However, as this report is drafted in April 2025, the impact of the federal government's proposed or current economic policies hamper price and cost predictions due to tariffs, tax policy, and cost of capital for the private sector.

to contracting, RPS portfolio positions, and RPS procurement rules. For instance, as noted in the Background, some retail sellers prefer Index + REC contracts, while others prefer "all-in" priced RPS contracts for energy, capacity, and RECs. Additionally, SMJUs are allowed to entirely use unbundled RECs to meet their RPS requirements. These differences make some comparisons amongst the retail sellers difficult or impossible in some instances.

Large Investor-Owned Utility Procurement Expenditures for 2024

The large IOUs' total annual RPS procurement expenditures in real-dollar value, for bundled IOU electric customers, grew 6.0 percent, from $5.0 billion in 2023 to $5.3 billion in 2024, reflecting a general rise in costs and continuing demand for energy. The increase in total expenditures was driven by the combined impact of IOUs' procurement to meet increasing RPS requirements and increasing demand. In 2024, IOUs procured 49,693 GWh versus 48,662 GWh in 2023, representing a 2.1 percent increase.

Weighted Average Expenditures for Large IOUs

The large IOUs' weighted average RPS procurement expenditures in 2024 were approximately 10.3 ¢/kWh across RPS contracts, excluding any utility-owned generation[15] (UOG). This 2024 average is slightly higher than the comparable 10.0 ¢/kWh average in 2023. When IOU UOG costs are included, this figure increases slightly given the relatively small amount of generation (approximately 2.1 percent of contracted volume purchased) that these UOG facilities presently contribute to the IOU RPS procurement portfolio. Including UOG facilities, the weighted average RPS procurement expenditures for IOUs increased from 10.3 ¢/kWh to 10.5 ¢/kWh. Detailed IOU 2024 RPS procurement expenditure information is summarized in Appendix B of this report, expressed as weighted averages in cents per kilowatt-hour (¢/kWh) categorized by IOU, technology, and size.[16]

Figure 1 illustrates the large IOUs' weighted average RPS procurement expenditures for renewable energy and associated RECs or bundled renewable energy in ¢/kWh from 2003 through 2024.[17,18] The changes in weighted average expenditures over time for each large IOU are similar, and the key factors driving the cost differences between the large IOUs are the resource mixes and contract vintages.

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15 UOG costs are determined by the actual fixed costs of the generation, similar to other utility infrastructure projects seen in general rate cases. UOG projects include the cost of capital, asset depreciation, operations and maintenance, taxes, etc.

16 The cost of RPS procurement expenditures is weighted based on actual quantities of energy delivered.

17 Bundled renewable energy is defined as renewable energy that is sold with its associated RECs as opposed to unbundled RECs or REC-only transaction where RECs are sold separately from the underlying renewable energy generation.

18 The weighted average RPS expenditures on this graph do not include RPS sales. For RPS Sales, refer to Table 1, or Voluntary Allocation and Market Offer transactions.

Figure 1: Weighted Average RPS Procurement Expenditures of Investor-Owned Utilities' Bundled Renewable Energy from 2003-2024 (Real Dollars)[19]

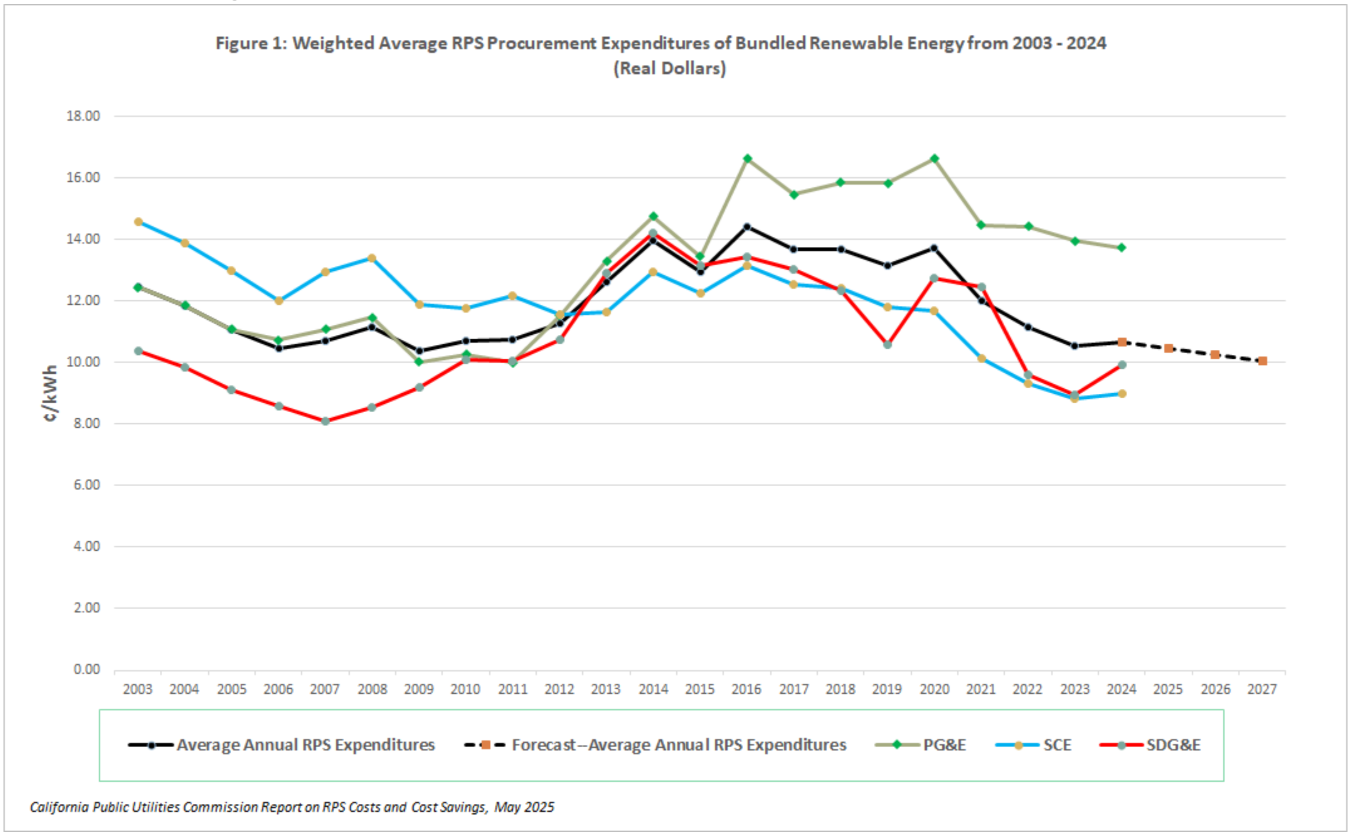


Figure 2 (below) shows the same average annual RPS expenditure data along with RPS contract prices executed in 2019 through 2024 for all retail sellers and IOUs' contract costs executed before 2019. (See Section 5 for details on RPS contract prices.) The added price data indicates a lag between the lower-priced contracts executed between 2016 and 2020 and the resulting decrease in average cost per kWh delivered to customers. This is because expenditures occur not when the contracts are signed but when the energy is generated because it can take several years from contract execution to when a project is built, interconnected, and begins to generate energy.

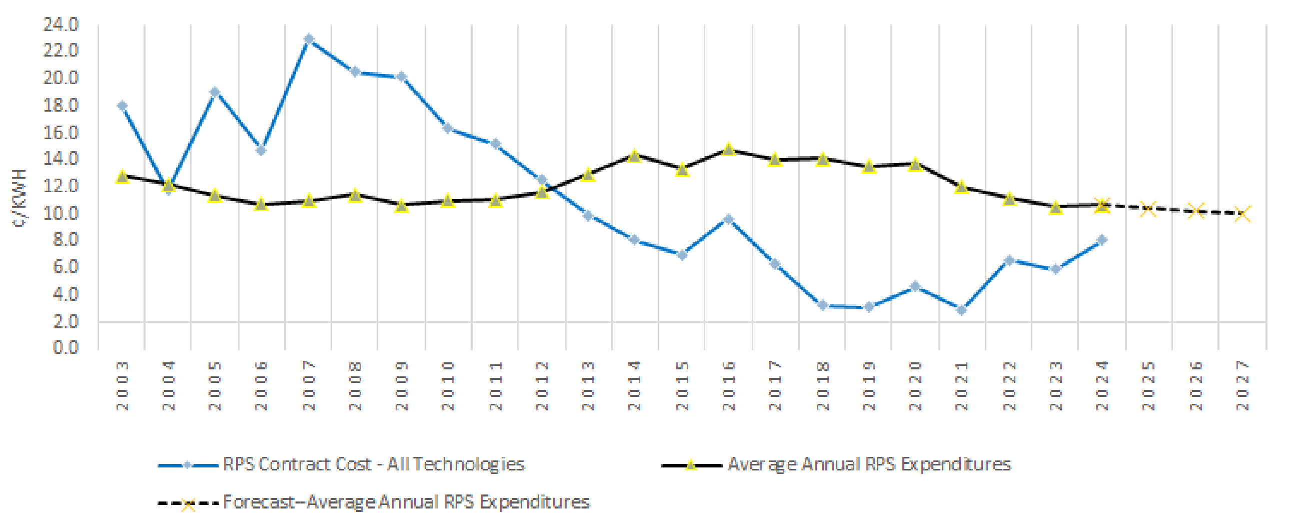
While 2024 expenditures increased over 2023, our near-term forecast of weighted average annual RPS expenditures for the large IOUs slightly decreases to reflect the fact that lower cost (relative to contracts executed 10 or more years ago) resources contracted within the past several years will begin to generate energy. It will still be a few years until the most recently executed, higher-priced contracts achieve operation and result in expenditures. As previously noted, costs associated with RPS expenditures reflect the conditions under

19 The values in this table have been adjusted to 2024 dollars utilizing U.S. Bureau of Labor Statistics inflation statistics.

which the contract was signed, while delivery of energy and its incorporation into electric rates could take place some years later.

To approximate the impact of the past decrease in contract prices on future expenditures, Figures 1 and 2 include a forecasted decline in average annual RPS expenditures at a rate of 2.0 percent per year between 2024 and 2027. The forecasted 2.0 percent drop in average RPS expenditures is significantly less than the historic 10.3 percent annual decrease in contract prices.[20] This forecast rate was chosen because, although new contracts are cheaper than the existing portfolio average, they make up a shrinking share of the overall RPS portfolio each year, which limits their impact on average costs.

Figure 2: RPS Program Expenditures and Fixed Contract Costs from 2003-2024[21] (in ¢/kWh, Real Dollars)



California Public Utilities Commission Report on RPS Costs and Cost Savings, May 2025

Large IOUs' RPS Sales Solicitations

In addition to procuring, the IOUs also conducted sales transactions to optimize their RPS portfolios. In 2024, retail sellers like CCAs or ESPs procured RPS energy from the large IOUs via RPS sales solicitations for RPS energy and renewable energy credits (RECs). RPS sales offer a path for smaller or newer retail sellers to procure RECs to meet their RPS compliance obligations while reducing the large IOUs' customers' costs; RPS sales result in revenues that offset total RPS expenditures. These revenues are not reflected in the above

[20] See Figure 2.

[21] All the data values in this table and other tables showing historical values have been adjusted for inflation using the U.S. Bureau of Labor Statistics' Producer Price Index (PPI) for the Electric Power Generation, Transmission, and Distribution Industry. This PPI was chosen as an effective method for capturing price movement specific to a given industry prior to retail level price changes.

data on IOU procurement expenditures. Table 2 below provides a summary of the large IOUs' RPS sales in 2024.

Table 12: Large IOUs' 2024 RPS Sales Summary

IOU	RPS Sales (GWh)	RPS Sales Revenue (millions $)
PG&E	8,572	375.9
SCE	7,592	360.1
SDG&E	4,234	211.0
Total	20,398	947.0

Voluntary Allocation and Market Offer

In addition to RPS sales, Voluntary Allocation and Market Offer (VAMO) transactions also provided IOUs with revenues. In D.21-05-030 the CPUC adopted the VAMO process with the intent of optimizing the IOUs' Power Charge Indifference Adjustment (PCIA)-eligible RPS portfolios, which had accumulated excess or uneconomic resources, primarily due to IOU load shifting to CCA service.

In 2022, the CPUC approved the IOUs' Voluntary Allocations of PCIA-eligible contracts based on each retail seller's forecasted, vintaged, annual load shares (MWh) and actual, vintaged, annual RPS energy production.[22] In 2023, the IOUs completed Market Offer solicitations for the resources remaining after the Voluntary Allocations.[23] Appendix F lists retail sellers that accepted Voluntary Allocations and counterparties to IOUs' Market Offer contracts.[24]

This year's report does not provide separate cost data on the VAMO transactions, nor does it incorporate these transactions into the retail sellers' reported procurement expenditures. They do impact the retail sellers' RPS portfolio overall procurement expenditures, though. For example, VAMO provides revenue for the IOUs and results in procurement expenditures for the CCAs and ESPs. Voluntary Allocations are valued at each year's respective Market Price Benchmark and Market Offer contracts negotiated prices. Revenues from the Voluntary Allocations are credited to Portfolio Allocation Balancing Accounts, reducing each IOUs' PCIA. Figure 3 below shows the amount IOUs have or will be allocated and selling to the CCAs and ESPs excluding allocations to the IOUs themselves.

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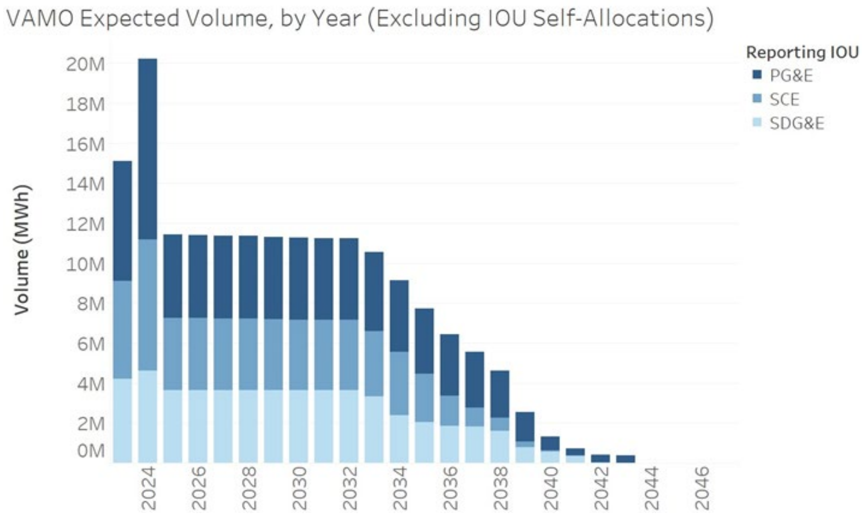
[22] D.22-11-021 at OP 1; D.21,05,030 at OP 7.

[23] D.22-11-021.

[24] D.22-11-021 at Attachment A.

Figure 3: Voluntary Allocations and Market Offers (VAMO) Volumes



Additionally pursuant to D.21-05-030, each of the IOUs issued Requests for Information (RFIs) in 2022 and 2023, seeking to amend, alter, or terminate legacy uneconomic contracts. As a result of its 2023 RFI, PG&E entered negotiations for termination agreements for two facilities: Ivanpah Solar Electric Generating Station Units 1 and 3. PG&E filed an Advice Letter on January 17, 2025, seeking approval of the finalized termination agreements, and the CPUC is currently considering this request.[25] SCE reports that its RFIs have not led to any results, and SDG&E reports it is still evaluating responses from its 2023 RFI.

Small and Multi-Jurisdictional Investor-Owned Utility Procurement Expenditures for 2024

In 2024, Liberty Utilities (Liberty), PacifiCorp, and Bear Valley Electric Service (BVES) spent nearly $24.0 million on RPS procurement as shown in Table 3. The SMJUs' RPS resources include biomass, geothermal, hydroelectric, solar photovoltaic, and wind.

Total SMJU Expenditures

For 2024, Liberty, PacifiCorp, and BVES had a total combined RPS procurement expenditure of $24.0 million compared to $18.3 million in 2023 in real-dollar value. The SMJUs' total renewable procurement increased by approximately 200 GWh from 495 GWh in 2023 to 695 GWh in 2024, which was the primary driver for increased total expenditures. This resulted in a 2024 RPS percentage of 33.9 percent of their total retail load. This also reflected a 7.1 percent increase in renewable energy generation as a proportion of retail load for SMJUs.

[25] PG&E Advice Letter 7485-E

Table 23: Small and Multi-Jurisdictional Investor-Owned Utilities' Total RPS Expenditures in 2024

	Liberty	PacifiCorp	Bear Valley Electric Service
Total (millions)	$12.40	$11.52	N/A[26]

Weighted SMJU Average Expenditures

In 2024, the weighted average RPS procurement expenditure for all Liberty contracts was 5.5 ¢/kWh, 2.5¢/kWh for PacifiCorp, and 1.0 ¢/kWh for BVES[27].

Community Choice Aggregator and Electric Service Provider Procurement Expenditures for 2024

In 2024, there were 25 CCAs and 11 ESPs that served load and procured RPS-eligible energy. All CCAs and ESPs covered in this report serve distribution customers of the three large IOUs. The CCAs' and ESPs' RPS portfolios include bioenergy, geothermal, small hydroelectric, solar photovoltaic, wind, and unbundled RECs. Tables 4 and 5 provide a summary of RPS procurement in 2023 and 2024 for CCAs and ESPs. The CCAs' total RPS fixed-price contract expenditures increased in 2024 primarily due to the corresponding increased amount procured.[28] Meanwhile, ESPs' total fixed-price expenditures and procurement in 2024 decreased slightly in comparison to 2023.[29]

It is important to note that the CCA and ESP RPS expenditures reported below cannot be directly compared to the IOUs' RPS procurement expenditures because a portion of delivered energy in 2024 for CCAs, and a large majority for ESPs, originated from Index + REC contracts. ESP and CCA Index + REC contracting trends are shown below in Figure 4.[30] The reported contract price for Index + REC contracts represents the incremental renewable cost, set at a negotiated amount in dollars per megawatt-hour ($/MWh) for the REC,

26 BVES's 2024 procurement expenditure data includes strictly REC-only contracts; therefore, it is not comparable to the other utilities' 2024 expenditures because their contracts include the cost of acquiring RECs, capacity, and energy.

27 BVES's 2024 procurement expenditure data includes strictly REC-only contracts; therefore, it is not comparable to the other utilities' 2024 expenditures as they procured significant quantities of contracts that include the cost of acquiring RECs, capacity, and energy.

28 For information regarding CCAs' forecasted RPS compliance, see CCAs' average actual and forecasted RPS percentages in the 2024 RPS Annual Report to the Legislature at 17.

29 For information regarding ESPs forecasted RPS compliance, see ESPs' average actual and forecasted RPS percentages in the 2024 RPS Annual Report to the Legislature at 18.

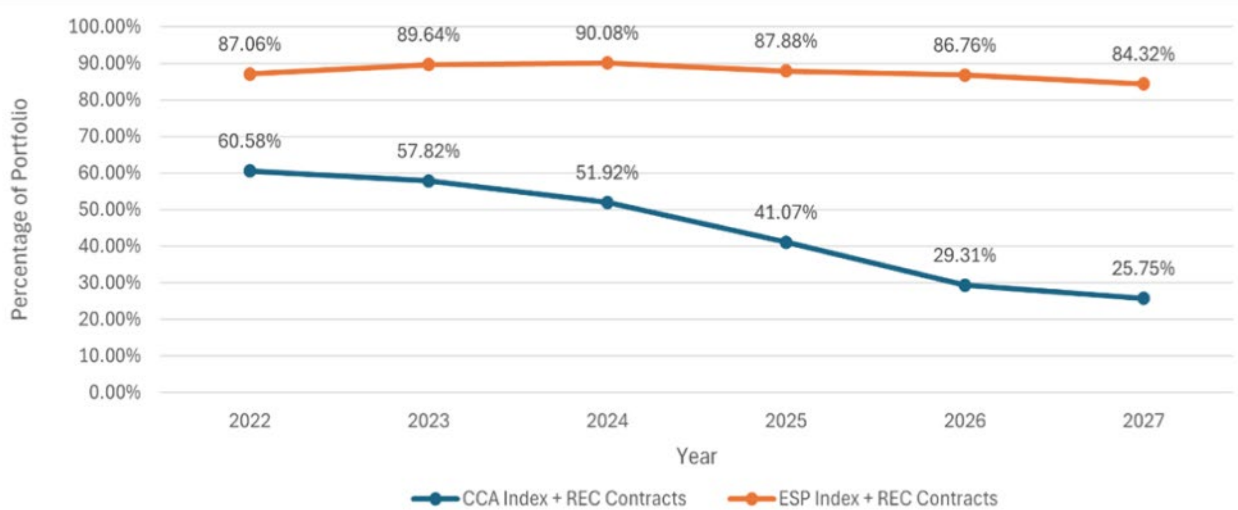
30 Index + REC contracts generally define "Index" energy as the CAISO Integrated Forward Market Day Ahead Price for CAISO SP-15 or NP-15 when the energy is delivered.

while the price for energy in these contracts can change depending on when electricity is delivered to the grid pursuant to the contract.[31]

Index + REC contracts differ significantly from "all-in" priced RPS contracts for energy, capacity, and RECs, where the price is set over the term of the contract. These "all-in" contracts make up the entirety of the IOUs' RPS portfolios. This difference in contract structure prevents comparison between the contract types. Moreover, Index + REC contracts introduce price volatility into the RPS program, despite being an issue which the RPS program was originally designed to address.

The weighted average expenditures and total expenditures for CCAs and ESPs detailed in Table 4 and Table 5 below do not incorporate the Index + REC contracts; they detail defined costs from fixed-price contracts which include both energy and REC. See Appendix B for detailed RPS weighted average expenditure data by technology and project size for CCAs and ESPs, respectively. In addition, it is important to consider contract vintages when comparing retail sellers' RPS costs, as the IOUs executed a majority of their RPS procurement contracts in earlier years when contract prices were generally higher than that of more recent CCA and ESP contracts.

Figure 4: Percentage of Index + REC Contracts in CCAs' and ESPs' RPS Portfolios



California Public Utilities Commission Report on RPS Costs and Savings, May 2025.

[31] In the CAISO's most recently released Annual Report on Market Issues and Performance, the average day-ahead energy price in was $65/MWh. (See CAISO's 2023 Annual Report on Market Issues and Performance, p. 5, (2023-annual-report-on-market-issues-and-performance.pdf). The price varies from the average depending on grid conditions and annual variations depend on market supply and demand. For example, the average day-ahead price in 2020 was $35/MWh.

Figure 4 shows the percentage of CCA and ESP RPS contracts with Index + REC price terms. The remaining contracts in their RPS portfolios are fixed-price.

CCAs as a group have been reducing their future reliance on Index + REC contracts in recent years, increasing the proportion of fixed-price contracts. The CCAs' shift to more fixed-price contracts is in part due to the availability of fixed-price terms with long-term contracts and the proportion of long-term contracts in all retail seller's portfolios has increased with the 65 percent long-term contracting rule becoming effective in 2021.[32] The CCAs' increased use of fixed-price contracts also means they now have a greater hedge against price fluctuations in the energy markets from their RPS portfolios.

On the other hand, ESPs as a group have maintained their use of Index + REC contracts. As a result, their RPS portfolios generally do not provide much of a hedge against price volatility in the energy markets. It is worth noting that not all CCAs and ESPs follow the trends of their peer groups: some ESPs are strategically hedging their exposure to energy markets with fixed-price RPS contracts and some CCAs are not hedging.

CCA Procurement Expenditures

CCAs' total annual RPS procurement expenditures for all contracts, including both fixed-price and Index + REC, increased 86.1 percent, from $806 million in 2023 to $1.5 billion in 2024, with a corresponding 25.3 percent increase in renewables generation from 30,380 GWh in 2023 to 38,071 GWh in 2024.

[32] Pursuant to D.17-06-026, starting in the 2021-2024 Compliance Period, each retail seller must demonstrate that at least 65 percent of its RECs are associated with long-term contracts. Prior to the statutory mandate of 65 percent introduced in SB 350, the requirement was a 0.25 percent "minimum quantity" requirement. In practice, the IOUs had a large percentage of RPS compliance sourced from long-term contracts prior to the long-term contracting requirement put in statute.

Table 4: Comparison of Community Choice Aggregator RPS Procurement and Procurement Expenditures between 2023 and 2024

	2023	2024
Weighted Average Fixed RPS Contract Expenditures (¢/kWh)	4.1	4.2
Total Fixed RPS Contract Expenditures (millions) [33]	$474.0	$785.7
Total Renewable Energy Delivered from Fixed RPS Contracts (GWh)[34]	11,639	18,713
Average RPS Procurement (Fixed and Indexed Contracts) Percentage[35]	59%	52%

ESPs Procurement Expenditures

The ESPs total annual RPS procurement expenditures for all contracts, both Fixed-Price and Index + REC, increased 67.7 percent, from $279 million in 2023 to $468 million in 2024, while total renewables generation increased 31.1 percent, from 8,414 GWh in 2023 to 11,034 GWh in 2024. The increases were primarily driven by a higher demand for RECs in the final year of Compliance Period 2021-2024 as retail sellers sought to meet their RPS obligations.

[33] Total expenditures are derived from CCA responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 1, 2025.

[34] Total renewable energy delivered is derived from CCA responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 1, 2025.

[35] RPS Procurement as a percentage of total load. See Table 4 in the 2024 RPS Annual Report to the Legislature (p. 15).

Table 5: Comparison of Electric Service Provider RPS Procurement and Procurement Expenditures between 2023 and 2024

	2023	2024
Weighted Average Fixed RPS Contract Expenditures (¢/kWh)	0.6	0.8
Total Fixed RPS Contract Expenditures (millions) [36]	$7.0	$6.1
Total Renewable Energy Delivered from Fixed RPS Contracts (GWh)[37]	778	722
Average RPS Procurement (Fixed and Indexed RPS Contracts) Percentage[38]	60%	36%

B. Comparison of RPS Procurement Expenditures to Revenue Requirements (Large IOUs Only)

The following section compares IOUs' RPS procurement expenditures to their revenue requirements. Because the 2024 revenue requirement information for Liberty, BVES, and PacifiCorp is currently confidential pursuant to CPUC confidentiality rules,[39] the CPUC is not able to publicly analyze SMJU costs compared to their revenue requirements for 2024. For the CCAs and ESPs, CPUC does not regulate the rates of CCAs or ESPs and therefore does not have their revenue requirement information.

Table 6 compares IOUs' RPS procurement expenditures to revenue requirements. Specifically, the table shows the percentage of RPS procurement compared to total procurement for these IOUs' generation portfolios, as well as the RPS procurement costs as a portion of the total revenue requirement. Additionally, Table 6 shows the large IOUs' RPS generation percentages for 2024.[40]

Table 6 also shows that in 2024, RPS procurement expenditures on average were less than 15.0 percent of the IOUs' total revenue requirements. The RPS expenditures make up a small portion of the total revenue

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[36] Total expenditures are derived from ESP responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 15, 2025.

[37] Total renewable energy delivered is derived from ESP responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 15, 2025.

[38] See Table 6 in the 2024 RPS Annual Report to the Legislature (p.19).

[39] See D.06-06-066, as modified, for confidentiality rules related to revenue requirements.

[40] For RPS compliance percentage see *RPS Annual Report to Legislature*: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/energy-reports-and-whitepapers/rps-reports-and-data

requirements, because total revenue requirements contain many large line items such as transmission costs, reliability costs, wildfire safety and mitigation program costs, administrative costs, and capital expenses. See *California Electric and Gas Utility Costs Report: AB 67 Annual Report to the Governor and Legislature* for details on these costs.[41]

Table 6: Comparison of Large Investor-Owned Utilities' RPS Procurement to Revenue Requirements in 2024[42,43]

IOU	RPS Generation as a Proportion of Total Generation	RPS Procurement Expenditures (billions)	Total Generation Revenue Requirement (billions)	RPS Procurement Expenditures to Total Generation Revenue Requirement (%)	Total Revenue Requirement (billions)	RPS Procurement Expenditures to Total Revenue Requirement (%)
PG&E	30.6%	$2.00	$5.34	37.5%	$17.68	11.3%
SCE	67.6%	$2.39	$6.17	38.8%	$16.41	14.6%
SDG&E	74.8%	$0.66	$0.79	83.5%	$3.54	18.6%

As retail sellers – including the large IOUs – are required to procure increasingly higher percentages of RPS-eligible energy, they are procuring less non-RPS-eligible energy for their electric portfolios. Consequently, the proportion of the revenue requirement that can be attributed to increased RPS procurement is difficult to calculate. However, considering that RPS energy is replacing non-RPS energy, one approximation is to compare the cost of RPS energy to non-RPS energy in retail sellers' portfolios.

In 2024, the large IOUs' average cost of renewable energy was 10.5 ¢/kWh and the average cost of non-RPS energy was 7.1 ¢/kWh.[44] Using this metric, large IOUs' renewable energy procurement likely added a premium of 3.4 ¢/kWh on average for the renewable energy procured to meet their RPS requirements.[45] However, as explained in Section 4 (below), this is an imperfect comparison, because it does not reflect likely savings from lower gas demand and resulting market effects.

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41 See https://www.cpuc.ca.gov/about-cpuc/divisions/office-of-governmental-affairs

42 Revenue requirement numbers have been taken from the CPUC's *2024 California Electric and Gas Utility Cost Report* pursuant to Public Utilities Code § 913, April 2025.

43 RPS generation percentages are calculated by dividing the IOUs' RPS generation serving retail load by the IOUs' total generation.

44 See Table 6.

45 The average RPS cost savings compared to non-RPS energy on a kilowatt-hour basis is represented by the following equation: 9.0 *¢/kWh (RPS Energy) – 7.0 ¢/kWh (Non-RPS Energy) = 2.0 ¢/kWh.*

4. Renewables Program Cost Premiums and/or Savings

Pursuant to §913.3(c) this section addresses the cost premiums and/or savings associated with the large IOUs', SMJUs', CCAs', and ESPs' procurement of renewable resources in 2024 as a result of meeting the RPS program requirements.

For the purposes of this report, the utilities' 2024 RPS procurement costs are compared to non-RPS procurement costs to determine cost savings. This comparison likely understates non-RPS procurement costs, since any premiums for avoided construction of new, and therefore more expensive, non-RPS resources and any gas cost savings resulting from lower gas demand are not reflected in this comparison[46].

However, it is difficult to quantify the cost savings, or avoided costs, associated with the RPS program because this would require assessing to what extent the RPS program deferred or replaced construction of alternative generation facilities and the theoretical cost of those alternative resources. As noted in previous versions of this report, several factors contribute to this uncertainty:

- The CPUC cannot estimate the impacts that increased renewables and the resulting reduction of natural gas demand has had on the cost of natural gas in California.
- Non-RPS resource costs, such as Resource Adequacy, are based on the preexisting supply of facilities and capacity need that are not tied to the same market considerations as RPS contracts.
- CCAs and ESPs primarily have contracts that do not provide fixed prices for energy and capacity and are tied to index prices, while IOUs' RPS contracts are "all-in" pricing that typically includes resource adequacy in the price. These differences limit and, in some instances, prevent cost comparisons in this report. This procurement approach may also introduce price volatility in California's RPS program which the program was designed in part to address.

Consequently, there is no perfect counterfactual to assess the RPS program's cost savings, because in the absence of RPS procurement, non-RPS resources would still be procured. This challenge is also reflected in the previous section's assessment of RPS expenditures as part of utilities' revenue requirements, in which the variables that inform the cost savings analysis are described as imperfect because they are not narrowly tailored to capture the benefits and costs of the RPS program.

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[46] R-Street research "If Renewable Energy Is Cheaper, Then Why Don't We Use It Exclusively?", January 10, 2025, Rossetti, Chandler. https://www.rstreet.org/commentary.

A. Large Investor-Owned Utilities' Cost Premiums / Savings

In 2024, the large IOUs' average annual RPS procurement expenditure represented a weighted average of 3.4 ¢/kWh cost premium versus their average non-RPS procurement expenditure (Table 7). Individually, PG&E and SCE both paid premiums for RPS procurement: 5.8 ¢/kWh and 7.0 ¢/kWh, respectively. Conversely, SDG&E paid a discount for RPS energy—compared to non-RPS energy—of 13.1 ¢/kWh. This pattern is in line with the most recent years, with non-RPS price levels declining for PG&E and SCE while rising for SDG&E. It is also possible that non-RPS expenditures have been influenced by factors such as the fuel cost volatility for non-RPS resources. Meanwhile, weighted average RPS expenditures in 2024 were five percent higher than 2023 expenditures on a cents per kWh basis.

Table 7: Large Investor-Owned Utilities' 2024 Average RPS and Non-RPS Eligible Procurement Expenditure[47] (¢/kWh)

Method	PG&E	SCE	SDG&E	Weighted Average
2024 Non-RPS	7.9	2.0	22.4	7.1
2024 RPS	13.8	9.0	9.9	10.5

Based on total volumes of RPS and non-RPS eligible procurement expenditures, the large IOUs are estimated to have realized the following cost savings or premiums versus an equivalent amount of Non-RPS procurement, displayed as positive or (negative) figures.

Table 8: Large Investor-Owned Utilities' 2024 RPS Cost Savings: Non-RPS Eligible Comparison

Cost Savings Compared to 2024 Average Non-RPS Expenditure (millions)	
PG&E	($931.30)
SCE	($1,878.77)
SDG&E	$829.20
Cost savings are displayed as positive figures while cost premiums are displayed as (negative) figures.	

[47] Derived from responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 15, 2025, and CPUC's 2023 AB 67 report, to be published May 2025.

B. Small and Multi-Jurisdictional Investor-Owned Utilities' Cost Premiums / Savings

In 2024, the RPS procurement expenditures for SMJUs represented cost savings compared to their average non-RPS-eligible expenditure. SMJUs are allowed to exclusively use unbundled RECs for RPS compliance, but this program difference does not drive the difference in procurement. SMJUs' RPS contracting started a bit later than IOU contracting, thus the total portfolios have fewer high-priced contracts from the early part of the RPS program. The weighted average RPS expenditures shown in Table 9 for both PacifiCorp and Liberty RPS portfolios contain energy and REC contracts and excludes any REC-only contracts so the procurement expenditures between RPS and non-RPS are comparable. The cost savings for RPS energy compared to non-RPS energy for Liberty and PacifiCorp was 1.7 ¢/kWh and 4.3 ¢/kWh, respectively. BVES' RPS procurement, however, consisted solely of REC-only products; thus, BVES' RPS expenditures are not directly comparable to their non-RPS expenditures, which include costs for energy and capacity that are not included in REC-only products and thus not included in Table 10.

Table 9: Small and Multi-Jurisdictional Investor-Owned Utilities' 2024 Average RPS and Non-RPS Eligible Procurement Expenditure (¢/kWh)

Method	Liberty	PacifiCorp	Bear Valley Electric Service	Weighted Average
2024 Non-RPS	7.2	6.8	6.3	6.9
2024 RPS	5.5	2.5	N/A[48]	N/A

Based on total volumes of RPS generation procured and non-RPS eligible procurement expenditures, the SMJUs realized the following cost savings (positive figures) or premiums (negative figures):

[48] BVES's 2024 procurement expenditure data includes strictly REC-only contracts; therefore, it is not comparable to non-RPS expenditures.

Table 10: Small and Multi-Jurisdictional Investor-Owned Utilities' 2024 RPS Cost Savings: Non-RPS Eligible Comparison[49]

Cost Savings Compared to 2024 Average Non-RPS Expenditure (millions)	
Liberty	$3.82
PacifiCorp	$16.99
Cost savings are displayed as positive figures while cost premiums are displayed as (negative) figures.	

C. Community Choice Aggregators' and ESPs Cost Premiums / Savings

In 2024, the RPS procurement expenditure for CCAs and ESPs represented a 1.9 ¢/kWh and 4.8 ¢/kWh cost savings, respectively, compared to their average non-RPS-eligible expenditure. As mentioned previously, the weighted average RPS expenditures for CCAs and ESPs excludes Index + REC contracts to be comparable to non-RPS generation, but they cannot be directly comparable to the IOUs' and SMJUs' RPS expenditures. Because of the exclusion, most of the ESPs' contracts (see Figure 4) are not incorporated in the below 2024 RPS weighted average expenditure figure. Based on total volumes of RPS generation procured and non-RPS eligible procurement expenditures, the CCAs and ESPs are estimated to have realized the following cost savings versus an equivalent amount of non-RPS procurement.

Table 11: Community Choice Aggregators' and CCAs' 2024 Average RPS, Non-RPS Eligible Procurement Expenditures and RPS Cost Savings Compared to Non-RPS Energy[50] **(¢/kWh)**

	2024 non-RPS Weighted Average (¢/kWh)	2024 RPS Weighted Average (¢/kWh)	Cost Savings Compared to 2024 Average Non-RPS Expenditure (million)
Community Choice Aggregators	6.1	4.2	$355.8
Electric Service Providers	5.6	0.8	$34.4

[49] Cost savings or premiums are calculated by multiplying each SMJU's average 2024 non-RPS eligible expenditure (cents/kWh) (Table 8) by its total volume of RPS procurement (kWh) in 2024 then subtracting that value from the SMJUs' 2024 RPS procurement expenditure ($) (Table 2).

[50] Cost savings or premiums are calculated by multiplying CCAs' average 2024 non-RPS eligible expenditure (Table 10) by volume of RPS procurement in 2024 (excluding Index + REC deliveries) then subtracting that value from the CCAs' 2024 RPS procurement expenditure (Table 3).

5. RPS Aggregated Contract Prices

As noted in the RPS Procurement Expenditures (Section 3.A of this report), contract prices affect procurement expenditure amounts. RPS contract price is the agreed amount to be paid for the RPS-eligible product pursuant to the executed contract, whereas the RPS procurement expenditures are the total costs for the procured RPS product from all contracts and weighted over all the RECs procured. Both metrics are reported in this report in cents/kWh.

Pursuant to §913.3(d) the following section provides a summary of 2024 RPS contract prices from contracts executed by retail sellers in 2024. In addition to contracts executed in 2024, this report also includes historical prices which have been adjusted in real dollars. Specifically, the CPUC examined the IOUs', CCAs', and ESPs' 2019 - 2024 executed contract prices.[51] Moreover, the CPUC also reviewed IOUs' RPS contracts executed between 2003 and 2018 to provide historic contract cost trends.[52] To remove non-representational trends, contracts with a nameplate capacity of 3 MW or less were not included in Figure 5.[53]

RPS Contract Prices for Resources Greater than 3 MW

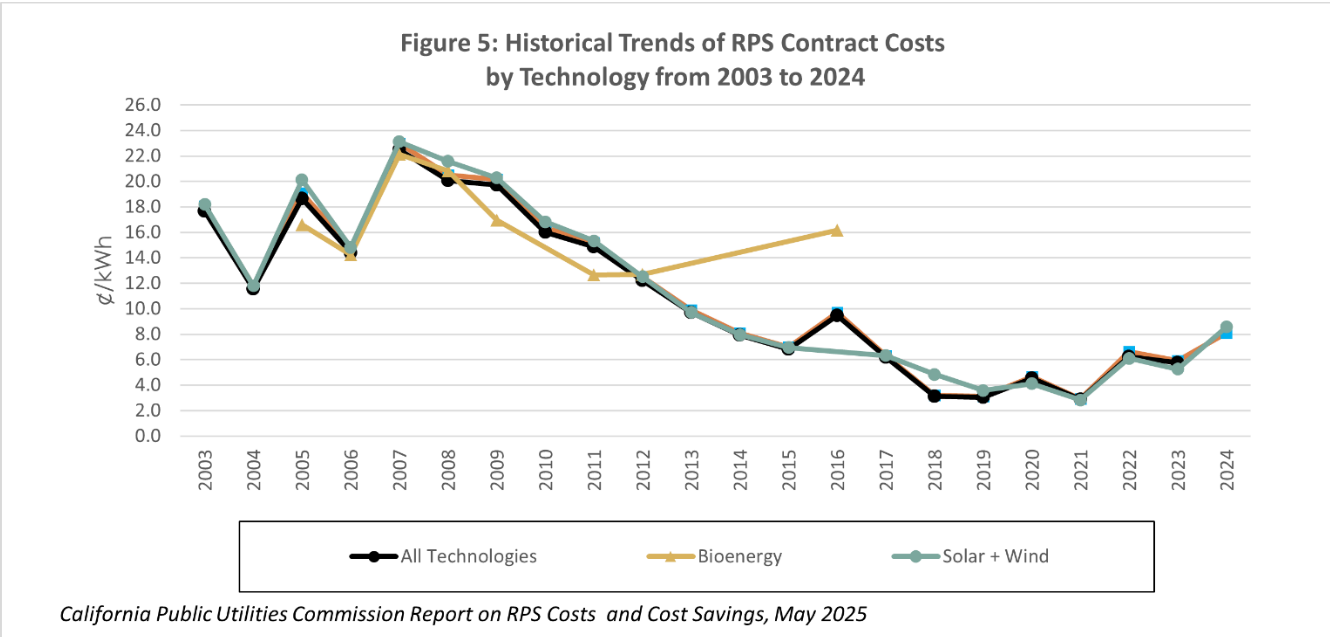
Figure 5 below shows that RPS contract prices, in real-dollar value, decreased an average of 5.6 percent annually between 2007 and 2024.

[51] 2019 through 2024 Contract price data for IOUs, CCAs and ESPs were obtained through a joint data request pursuant to PU Code Section 913.3 and the *Power Charge Indifference Adjustment (PCIA)* proceeding. Contract data for 2003-2018 was self-reported by the IOUs through the CPUC's RPS Executed Projects Database.

[52] *See id.*

[53] Projects with a capacity of 3 MW or less made up a little over 1 percent of all the IOUs' contracted RPS capacity, and removing these figures eliminated non-representative trends from the data. As a result of this size exclusion, feed-in-tariff projects were not considered in the analysis above, but are incorporated in Appendix C. In California, feed-in-tariff programs offer projects with a capacity of 3 MW or less a predetermined price ($/MWh) to encourage market transformation for projects at these sizes. Additionally, contracts identified as REC-only payments were excluded as these values are not comparable to all-in energy, capacity, and REC contract prices.

Figure 5: Historical Trends of RPS Contract Costs by Technology from 2003 to 2024



Note: The All Technologies line includes bioenergy and solar+wind, although those are shown separately for comparison. The bioenergy line does not extend further due to the lack of new contracting. Other technologies beyond bioenergy, solar + wind, are included in the all-technologies line, but not broken out because there are not enough contracts to mask confidentiality.

The historic contract price trends for the RPS program seen in Figure 5 show that executed contract prices peaked in 2007 and have been generally falling for RPS-eligible resources, but they have risen slightly (in inflation-adjusted dollars) over the last few years. The average price of IOU, CCA, and ESP RPS contracts executed in 2024 that were greater than 3.0 MW continues this more recent trend of increasing prices. Specifically, the average price in 2024 was 8.1¢/kWh compared to 5.9 ¢/kWh in real-dollar value in 2023. This 37.3 percent increase was likely driven by an increased demand to meet end of RPS Compliance Period 2021-2024 requirements, uncertainty of supply chain constraints, potential impact of increasing inflation rates and higher interest rates. See Appendix C for 2024 contract price data.

RPS Contract Prices for Resources 3 MW and Less

As noted above, RPS resources with a nameplate capacity of 3.0 MW or less are not included in Figure 5. Accordingly, the large IOU's contracts signed in 2024 under the Renewable Market Adjust Tariff (ReMAT) and Bioenergy Market Adjusting Tariff (BioMAT) programs were not included in the above figure.

IOU Renewable Market Adjusting Tariff (ReMAT) Contracts

ReMAT is a feed-in-tariff program for small RPS-eligible facilities such as small hydro, solar PV, and wind, to sell renewable electricity to the IOUs under standard terms and conditions. ReMAT projects fall under three product types: As-Available Peaking, As-Available Non-Peaking, and Baseload. The contract price offered for each product type is calculated using recent wholesale RPS contracts and is updated annually by CPUC resolution. See Table 12 for the 2024 ReMAT prices. No ReMAT contracts were executed in 2024.

Table 12: 2024 ReMAT Prices by Product Category

ReMAT Product Category	2024 ReMAT Prices (¢/kWh)
As-Available Non-Peaking	5.29
As-Available Peaking	7.19
Baseload	7.59

IOU Bioenergy Market Adjusting Tariff (BioMAT) Contracts

BioMAT is a bioenergy Feed-in-Tariff program that allocates procurement to the discrete bioenergy categories of Biogas, Dairy/Agriculture, and Sustainable Forest Management. BioMAT uses a standard contract and a market-based mechanism to arrive at the offered program contract price. Table 13 shows the 2024 BioMAT contract prices. One BioMAT contract was executed in 2024.

Table 13: 2024 BioMAT Prices by BioMAT Category

BioMAT Category	BioMAT Prices (¢/kWh)
Biogas	12.77
Dairy/Agriculture	18.72 / 18.37
Sustainable Forest Management	19.97

CCA Feed-in-Tariff Contracts and Facilities 3 MW or Less

The CCAs are not required to offer BioMAT or ReMAT contracts. During 2024, the CCAs did not execute any new-build RPS-eligible facilities with 3.0 MW or less of capacity.[54] In November 2023, CCAs were authorized to join the BioMAT program, but did not execute any BioMAT contracts in 2024.

Bioenergy Renewable Auction Mechanism (BioRAM) Contracts

Pursuant to the Governor's Emergency Order Addressing Tree Mortality, SB 859 and SB 901, the BioRAM program required the large IOUs to procure 146.0 MWs of bioenergy from High Hazard Zones to aid in mitigating the threat of wildfires. Since 2016, the IOUs have executed contracts with seven biomass facilities to meet their BioRAM procurement requirements.[55]

In 2024, there existing six biomass facilities contracted total 154 MW and have an average contract price of 12.0 ¢/kWh. No BioRAM contracts were executed in 2024.

[54] This data was obtained through the joint RPS-PCIA Semi-Annual Data Report, submitted February 3, 2025.

[55] CCAs and ESPs are not required to execute BioRAM contracts but are allocated a proportional cost through a non-bypassable charge.

6. Appendices

Appendix A: California Public Utilities Commission RPS Activities and Milestones

January 2024	▪ CPUC approved BioMAT Tariff Modifications in compliance with AB 843. ▪ CPUC adopted the new RPS Order Instituting Rulemaking 24-01-017. ▪ CPUC adopted Resolution E-5297 approving a PPA for a zero-emissions product from a hybrid solar photovoltaic plus lithium-ion battery storage facility.
February 2024	▪ CPUC adopted D.24-02-047 adopting 2023 preferred system plan.
March 2024	▪ CPUC adopted D.24-03-003, denying a BioRAM PFM.
April 2024	▪ CPUC notified Retail Sellers of the final determinations for the 2017-2020 Compliance period.
May 2024	▪ CPUC approved IOUs' recommendation to refrain from scheduling additional VAMO processes. ▪ CPUC adopted Resolution E-5313 approving SCE Renewables Mid-Term Reliability PPAs. ▪ CPUC adopted Resolution E-5318 approving SDG&E's RPS Solicitation Protocols. ▪ CPUC issued the 2024 Padilla Report on Costs and Cost Savings for the RPS Program to the Legislature, pursuant to Public Utilities Code § 913.3: https://www.cpuc.ca.gov/RPS_Reports_Data/ ▪ CPUC issued the Assigned Commissioner and Assigned Administrative Law Judge's Ruling issued identifying issues and schedule of review for 2024 RPS Procurement Plans. ▪ CPUC issued a Scoping Memo for R.24-01-017 to set forth the initial schedule and issues for consideration in the RPS proceeding
June 2024	▪ Adoption of 2024 updated administratively set fixed avoided-cost rates for the ReMAT (Resolution E-5323) ▪ CPUC issued an Assigned Administrative Law Judge's Ruling requesting party comments on a Staff Proposal for clarifying RPS Procurement Plans confidentiality rules
July 2024	▪ IOUs, SMJUs, CCAs, and ESPs submitted Draft 2024 RPS Procurement Plans. ▪ CPUC adopted Resolution E-5333 approving SCE Renewables Mid-Term Reliability PPAs.

August 2024	▪ IOUs, CCAs, and ESPs submitted annual RPS Compliance Reports. ▪ CPUC adopted Resolution E-5343 approving PacifiCorp long-term REC contract with 3Degrees Group, Inc. ▪ CPUC adopted D.24-08-064 - Decision Determining Need for Centralized Procurement of Long Lead-Time Resources. ▪ CPUC launched a new RPS Database.
September 2024	▪ CPUC issued proposed Decision on Motions for Waiver of Renewables Portfolio Standard Program Requirement for Compliance Period 2017-2020
October 2024	▪ CPUC adopted D.24-10-009 on Motions for Waiver of Renewables Portfolio Standard Program Requirement for Compliance Period 2017-2020.
November 2024	▪ CPUC issued annual SB 155 compliance notification letters.
December 2024	▪ CPUC issued the 2024 Annual RPS Report to the Legislature. ▪ CPUC adopted D.24-12-035 on the 2024 RPS Procurement Plans.

Appendix B: RPS Procurement Expenditures per Public Utilities Code § 913.3

Overview of Tables

Table B-1 shows, for each large IOU, the weighted average time-of-delivery (TOD) adjusted RPS procurement expenditures for 2024.[56] Tables B-2 and B-3 show the weighted average RPS procurement expenditures for 2024 for CCAs and ESPs. Per the confidentiality requirements in Public Utilities Code § 913.3, some of the data within this report is redacted to protect market sensitive information.

For the IOUs, RPS procurement expenditures are driven by a large volume of contracts signed between 2007 and 2016 most of which were at higher prices compared to prices observed in the current market.[57] The most recent RPS contracts executed at relatively lower prices are not fully reflected in the weighted average RPS procurement expenditures below because there is a lag between when the lower cost contracts are executed and when RPS weighted procurement expenditures will decline.

In addition:

- The "Average RPS Procurement Expenditures" represent the total weighted average payments made for RPS generation for 2024.
- Procurement expenditures represent averages weighted by capacity procured on a per kilowatt-hour basis. All figures are in 2024 dollars.

[56] Table B-1 provides all procurement expenditure information for every large IOU RPS-eligible contract, including utility-owned generation (UOG) projects. The tables break down the actual price for production in 2024 of UOG, which includes small hydroelectric and solar photovoltaic facilities. At the inception of the three IOUs' solar photovoltaic programs (SPVP-UOG), the CPUC approved an average levelized cost of energy (LCOE) for each IOU. For PG&E's UOG projects, the CPUC approved an average LCOE of $0.25/kWh. (D.10-04-052 at 36.) For SCE's UOG projects, the CPUC approved an average LCOE of $0.26/kWh. (D.09-06-049 at 31.) For SDG&E's UOG projects, the CPUC approved an average LCOE of $0.24/kWh. (D.10-09-016 at 32.) The UOG small hydroelectric facilities used for 2023 RPS generation began commercial operation primarily between 1900 and 1960.

[57] See historical trend of RPS contract costs in Figure 5.

Table B-1. Weighted Average RPS Procurement Expenditures for IOUs in 2024 (¢/kWh)

	PG&E	SCE	SDG&E	Weighted Average
Biogas				
0-3 MW	Only 1 Contract	11.1	9.8	10.6
+3-20 MW	Only 2 Contracts	Only 1 Contract	Only 1 Contract	9.6
Biogas Total	**12.1**	**9.7**	**6.0**	**9.8**
Biomass				
0-3 MW	18.1			18.1
+3-20 MW	-	Only 1 Contract		-
+20-50 MW	12.2	Only 1 Contract	Only 1 Contract	12.0
+50-200 MW	Only 1 Contract			-
Biomass Total	**11.6**	**-**	**Only 1 Contract**	**11.6**
Geothermal				
+3-20 MW	Only 2 Contracts	Only 1 Contract	-	8.0
+20-50 MW		Only 2 Contracts		-
+50-200 MW		Only 1 Contract		-
+200 MW		Only 1 Contract		-
Geothermal Total	**Only 2 Contracts**	**7.4**	**-**	**7.5**
Small Hydro				
0-3 MW	12.6	7.0	0.4	7.8
+3-20 MW	Only 2 Contracts	7.0		7.1
+20-50 MW	11.0	Only 1 Contract		7.0
Small Hydro Total	**11.45**	**5.3**	**0.4**	**7.3**
Solar Photovoltaic				
0-3 MW	11.7	12.2	20.9	13.0
+3-20 MW	10.0	9.0	9.0	9.4
+20-50 MW	14.0	Only 1 Contract	Only 2 Contracts	13.1
+50-200 MW	12.2	6.0	12.8	9.0
+200 MW	17.1	12.0	-	14.0
Solar Photovoltaic Total	**14.1**	**9.0**	**12.5**	**11.1**
Solar Thermal				
+50-200 MW	Only 2 Contracts	Only 1 Contract	-	16.1
+200 MW	Only 2 Contracts			20.9
Solar Thermal Total	**19.7**	**-**	**-**	**19.0**
Wind				
0-3 MW	-	Only 2 Contracts	-	-
+3-20 MW	Only 2 Contracts	Only 2 Contracts	8.2	6.6
+20-50 MW	Only 1 Contract	Only 2 Contracts	Only 1 Contract	8.7
+50-200 MW	7.9	9.5	7.0	8.6
+200 MW		8.6	Only 1 Contract	-
Wind Total	**7.9**	**9.3**	**7.4**	**8.6**
UOG Small Hydro				
0-3 MW	105.2	-		105.2
+3-20 MW	33.5	-		33.5
+20-50 MW	Only 1 Contract	-		Only 1 Contract
UOG Small Hydro Total	**35.0**	**-**	**-**	**35.0**
UOG Solar Photovoltaic				
0-3 MW	Only 2 Contracts	-	-	-
+3-20 MW	23.4	-	-	23.4
UOG Solar Photovoltaic Total	**23.5**	**-**	**-**	**23.4**

Weighted Average of All Resources	**13.4**	**9.0**	**9.9**	**10.5**[58]

58 Does not include Index + REC contracts

Table B-2. Weighted Average RPS Procurement Expenditures for CCAs (Bundled Energy, Index + REC, and REC-Only Transactions) for 2024 (¢/kWh)

	All Contract Weighted Average[59]	Index +REC Weighted Average
Biogas		
0-3 MW	-	0.3
Index + REC (excludes cost of energy index)	-	0.3
Biogas Total	**-**	**0.3**
Biomass		
0-3 MW	-	1.1
3-20 MW	-	1.2
Index + REC (excludes cost of energy index)	-	1.2
Biomass Total	**-**	**1.2**
Geothermal		
3-20 MW	Only 2 Contracts	
20-50 MW	Only 2 Contracts	
Index + REC (excludes cost of energy index)	-	-
Geothermal Total	**5.9**	**-**
Small Hydro		
0-3 MW	Only 2 Contracts	Only 1 Contract
3-20 MW	Only 1 Contract	Only 1 Contract
Index + REC (excludes cost of energy index)	-	Only 2 Contracts
Small Hydro Total	**5.1**	**Only 2 Contracts**
Solar Photovoltaic		
0-3 MW	12.0	4.5
3-20 MW	Only 1 Contract	Only 1 Contract
20-50 MW	Only 2 Contracts	Only 1 Contract
50-200 MW	3.0	1.4
Index + REC (excludes cost of energy index)	-	-
Solar Photovoltaic Total	**3.2**	**2.4**
Various/REC-Only[60]		
0-3 MW	3.4	3.9
3- 20 MW		Only 1 Contract
20 -50 MW		Only 1 Contact
+200 MW		Only 2 Contracts
Index + REC (excludes cost of energy index)	-	
Various/REC-Only Total	3.4	4.0
Wind		
0-3 MW	Only 1 Contract	4.2
3-20MW	4.9	1.3
20-50 MW	Only 1 Contract	7.2
50-200 MW		Only 1 Contract
+200 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)		4.6
Wind Total	**4.2**	**4.6**
Weighted Average of All Resources	**4.2**	**3.6**[61]

[59] Totals for each technology type exclude expenditures from Index + REC contracts.
[60] The "Various" technology type indicates energy plus REC contracts where the technology type of the procurement is not yet known by the buyer. This arrangement occurs when an LSE procures energy and RECs from multiple facilities in a seller's portfolio. The technology type is known to the buyer after the energy and RECs are delivered to the electricity grid.
[61] Excludes Various/REC-only expenditures.

Table B-3. Weighted Average RPS Procurement Expenditures for ESPs

(Bundled Energy, Index + REC, and REC-Only Transactions) for 2024 (¢/kWh)

	All Contract Weighted Average	Index + REC Weighted Average
Biogas		
0-3 MW	Only 2 Contracts	
Index + REC (excludes cost of energy index)		Only 1 Contract
Biogas Total	**Only 2 Contracts**	**Only 1 Contract**
Biomass		
Index + REC (excludes cost of energy index)	-	Only 2 Contracts
Biomass Total	**-**	**Only 2 Contracts**
Geothermal		
0-3 MW	-	
Index + REC (excludes cost of energy index)		0.3
Geothermal Total	**-**	**0.3**
Small Hydro		
0-3 MW	Only 2 Contracts	
Index + REC (excludes cost of energy index)		5.8
Small Hydro Total	**Only 2 Contracts**	**5.8**
Solar Photovoltaic		
0-3 MW	Only 1 Contract	7.1
3-20 MW		Only 1 Contract
20-50 MW		Only 2 Contracts
50-200 MW		1.2
+200 MW		Only 2 Contracts
Index +REC (excludes cost of energy index)		5.1
Solar Photovoltaic Total	Only 1 Contract	**5.1**
Wind		
0-3 MW	-	6.2
20-50 MW		Only 1 Contract
50-200 MW		1.6
Index + REC (excludes cost of energy index)		
Wind Total	**-**	**5.8**
Various/REC Only		
0-3 MW	0.5	4.5
3-20 MW		Only 1 Contract
+200 MW		Only 1 Contract
Index + REC (excludes cost of energy index)		
Various/REC-Only Total	**0.5**	**4.4**
Weighted Average of All Resources	**0.8**	**5.0**[62]

[62] Excludes Various/REC-Only expenditures.

Appendix C: Contract Price Data per Senate Bill 836 (Public Utilities Code § 913.3)

Overview of Contract Price Data

Table C-1 shows the weighted average time-of-delivery (TOD) adjusted contract price for all the large IOUs' RPS contracts approved by the CPUC in 2024. Tables C-2 and C3 show the weighted average contract prices for the CCA and ESP RPS contracts executed in 2024.

Per the confidentiality requirements in Public Utilities Code § 913.3, some of the data within this appendix is redacted. Contract prices are redacted if a) the power purchase agreement (PPA) is not already public on the CPUC's website per the CPUC's confidentiality rules, and b) there are fewer than three facilities in each category. If there is only one facility in a category and its PPA is publicly available on the CPUC's website, then the price information for that facility is reported. In addition, the following contracts are public and reported: all qualifying facility (QF) contracts that do not require CPUC approval, feed-in tariff contracts, contracts with municipal governments, affiliate entities, and UOG costs. Weighted average contract prices represent contract prices weighted by capacity procured on a per kilowatt-hour basis. All figures are in 2024 dollars. All IOU contracts with TOD-adjusted prices have been adjusted by those TOD factors because generators are paid based on the time that the facility delivers electricity. TOD factors are intended to pay a premium on generation that occurs during peak demand hours when electricity is more valuable.

Table C-1. Average TOD-Adjusted Price of All Renewable Energy Contracts Approved for 2024 for IOUs (¢/kWh)

Approved in 2024 for IOUs (¢/kWh)	PG&E	SCE	SDG&E	Total
Biomass				
0-3 MW	Only 1 Contract			-
Biomass Total	**Only 1 Contract**			
Small Hydro				
0-3 MW	Only 2 Contracts			-
Small Hydro Total	**Only 2 Contracts**			**-**
Solar Photovoltaic				
0-3 MW	Only 1 Contract			-
+3-20 MW		3.6		3.6
+20-50 MW				
+50-200 MW	Only 2 Contracts	4.7		4.6
+200 MW	Only 2 Contracts			-
Solar Photovoltaic Total	**3.8**	**4.1**	**-**	**4.0**
Average of All Resources	**10.1**	**4.2**	**-**	**7.0**

Table C-2. Average Contract Price of All Renewable Energy Contracts Executed in 2024 With Anticipated Delivery in Future Years for CCAs (¢/kWh)
Including Index + REC contracts

Executed in 2024 for CCAs (¢/kWh)	Total	REC
Hybrid		
3-20 MW	Only 1 Contract	
20-50 MW		
Index + REC (excludes cost of energy index)		-
Hybrid Total	**-**	**-**
Small Hydro		
0-3 MW	Only 1 Contract	
3-20 MW		
20-50 MW		
Index + REC (excludes cost of energy index)		
Small Hydro Total	**-**	**-**
Solar Photovoltaic		
0-3 MW	11.0	
3-20 MW	4.6	
20-50 MW	4.2	
50-200 MW	Only 2 Contracts	
+200 MW	Only 2 Contracts	
Index + REC (excludes cost of energy index)		5.6
Solar Photovoltaic Total	**6.3**	**5.6**
Various/REC-Only[63]		
Index + REC (excludes cost of energy index)		**6.1**
REC-Only	**-**	**-**
Wind		
3-20 MW	Only 1 Contract	
20-50 MW		
50-200 MW	Only 1 Contract	
+200 MW		
Index + REC (excludes cost of energy index)		-
Wind Total	**-**	**-**
Average of All Resources	**6.6**	**5.9**[64]

63 The "Various" technology type indicates energy and REC contracts where the technology type of the procurement is not yet known by the buyer. This arrangement occurs when an LSE procures energy and RECs from multiple facilities in a seller's portfolio. The technology type is known to the buyer when the energy and RECs are delivered to the electricity grid.

64 Excludes Various/REC-Only contracts.

Table C-3. Average Contract Price of All Renewable Energy Contracts Executed in 2024 With Anticipated Delivery in Future Years for ESPs Including Index + REC Contracts (¢/kWh)

Executed in 2024 for ESPs (¢/kWh)	Total	REC
Biogas		
Index + REC (excludes cost of energy index)		Only 1 Contract
Biogas Total		Only 1 Contract
Various/REC-Only[65]		
0-3 MW		
Index + REC (excludes cost of energy index)		-
REC-Only		-
Wind		
50-200 MW	-	
Index + REC (excludes cost of energy index)		
Wind Total	-	-
Average of All Resources	-	**Only 1 Contract[66]**

[65] The "Various" technology type indicates energy and REC contracts where the technology type of the procurement is not yet known by the buyer. This arrangement occurs when an LSE procures energy and RECs from multiple facilities in a seller's portfolio. The technology type is known to the buyer when the energy and RECs are delivered to the electricity grid.

[66] Excludes Various/REC-Only contracts.

Appendix D: Public Utilities Code § 913.3(a)–(d)

Text of Public Utilities Code § 913.3(a)–(d)

913.3. (a) Notwithstanding subdivision (g) of § 454.5 and § 583, no later than May 1 of each year, the commission shall release to the Legislature for the preceding calendar year the costs of all electricity procurement contracts for eligible renewable energy resources, including unbundled renewable energy credits, and all costs for utility-owned generation approved by the commission.

(1) For power purchase contracts, the commission shall release costs in an aggregated form categorized according to the year the procurement transaction was approved by the commission, the eligible renewable energy resource type, including bundled renewable energy credits, the average executed contract price, and average actual recorded costs for each kilowatt-hour of production. Within each renewable energy resource type, the commission shall provide aggregated costs for different project size thresholds.

(2) For each utility-owned renewable generation project, the commission shall release the costs forecast by the electrical corporation at the time of initial approval and the actual recorded costs for each kilowatt-hour of production during the preceding calendar year.

(b) The commission shall report all electrical corporation revenue requirement increases associated with meeting the renewables portfolio standard, as defined in § 399.12, including direct procurement costs for eligible renewable energy resources and renewable energy credits.

(c) The commission shall report all cost savings experienced, or costs avoided, by electrical corporations as a result of meeting the renewables portfolio standard.

(d) This section does not require the release of the terms of any individual electricity procurement contracts for eligible renewable energy resources, including unbundled renewable energy credits, approved by the commission. The commission shall aggregate data to the extent required to ensure protection of the confidentiality of individual contract costs even if this aggregation requires grouping contracts of different energy resource types. The commission shall not be required to release the data in any year when there are fewer than three contracts approved.

Appendix E – Glossary of Acronyms and Terms

(BioMAT) Bioenergy Market Adjusting Tariff: A feed-in tariff program for bioenergy renewable generators less than 3 MW in size.

(BioRAM) Bioenergy Renewable Auction Mechanism: An RPS program that implements the Governor's October 2015 Emergency Order on Tree Mortality, as well as SB 859 (Chapter 368, Statues of 2016), and mandates utilities to procure bioenergy from forest fuel from High Hazard Zones (HHZ) to mitigate the threat of wildfires.

"Bundled" IOU customers: customers that receive both generation and transmission/distribution from an IOU.

(CAISO) California Independent System Operator: The CAISO manages the flow of electricity across high-voltage, long-distance power lines, operates a competitive wholesale energy market, and oversees transmission planning.

(CEC) California Energy Commission: A state agency responsible for, among other things, forecasting future energy needs and keeping historical energy data, licensing thermal power plants 50 megawatts or larger, promoting energy efficiency through appliance and building standards, and developing energy technologies and supporting renewable energy. It is overseen by a Governor-appointed five-person board.

(CCA) Community Choice Aggregator: Local government agencies that purchase and may develop power on behalf of residents, businesses, and municipal facilities within a local or sub-regional area. As of November 1, 2024, there are 25 active CCAs, as listed in Appendix F.

(ESP) Electric Service Provider: An entity that offers electrical service to commercial and industrial customers within the service territory of an electrical corporation and includes the unregulated affiliates and subsidiaries of an electrical corporation. Appendix F lists the 10 active ESPs.

(FIT) Feed-in Tariff: The FIT program is a policy mechanism designed to accelerate investment in small, distributed renewable energy technologies. The FIT program offers long-term contracts and price certainty for financing renewable energy investments. The RPS program has two FIT programs, ReMAT and BioMAT.

(HHZ) High Hazard Zone: Due to several consecutive years of drought between 2012 and 2017 in California exasperated wildfire conditions. The millions of recently dead trees have created locally increased hazards related to fire and potential falling trees, and greatly impacts public safety and forest health. High Hazard Zones identify those priority areas for dead tree removal and fire hazard reduction.

Index + REC contracts: contracts where a REC price is set at a negotiated amount in dollars per megawatt-hour ($/MWh) with "Index" or energy price is defined as the CAISO Integrated Forward Market Day Ahead Price for CAISO SP-15 or NP-15 when the energy is delivered.

(IOU) Investor-Owned Utility: IOUs are privately owned electricity and natural gas providers and are regulated by the California Public Utilities Commission (CPUC). Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric comprise approximately 40 percent of the retail electricity supply in California.

(LSE) Load Serving Entity: All entities that serve electricity to customers including IOUs, SMJUs, CCAs, ESPs, and Public Owned Utilities.

(OIR) Order Instituting Rulemaking: An investigatory proceeding opened to consider the creation or revision of rules or guidelines in a matter affecting multiple utilities or a broad sector of the industry.

(PCIA) Power Charge Indifference Adjustment: Charge to customers that departed a utility for costs that utility incurred in anticipation of serving the customers to ensure remaining customers are not burdened by the departure of those customers.

(PFM) Petition for Modification: Formal CPUC process where an entity may request that a previously established CPUC form formal action, such as a decision, be reconsidered for modification.

(PPA) Power Purchase Agreement: The contractual agreement under which the financial and technical aspects of renewable energy generation projects are agreed upon between power sellers and retail sellers.

(POU) Publicly Owned Utility: POUs are publicly owned, non-profit electricity and natural gas providers. POUs comprises approximately 26 percent of the retail electricity supply in California.

(RA) Resource Adequacy: The ability of a utilities' reliable capacity resources (supply) to meet customers' energy or system loads (demands) at all hours.

(RAM) Renewable Auction Mechanism: An RPS procurement process the IOUs may use to procure RPS generation and to satisfy authorized procurement needs or legislative mandates. RAM streamlines the procurement process for developers, utilities, and regulators by 1) allowing project bidders to set their own price, 2) providing a simple standard contract for each utility, and 3) allowing all contracts to be submitted to the CPUC through an expedited regulatory review process.

(REC) Renewable Energy Credit: A market-based instrument that represents the property rights to the environmental, social and other non-power attributes associated with the production of electricity from a renewable source. RECs play an important role in driving the deployment of renewable energy in California and achieving the goals of RPS. A REC confers to its holder a claim on the renewable attributes of one unit of energy (MWh) generated from a renewable resource. RECs are "created" by a renewable generator simultaneous to the production of electricity and can subsequently be sold separately from the underlying energy.

(ReMAT) Renewable Market Adjusting Tariff: A feed-in tariff program for small renewable generators up to 3 MW in size.

Retail Sellers: All entities that sell electricity to customers, including IOUs, CCAs and ESPs. A Publicly Owned Utility (POU) does not meet the definition of a retail seller and POU compliance with the RPS program is overseen by the CEC.

(SMJU) Small and Multi-Jurisdictional Utility: Investor-owned utilities that are considered small and multi-jurisdictional subject to different rules per PUC § 399.17 and § 399.18. The three SMJUs are listed in Appendix E.

(UOG) Utility-Owned Generation: generation facilities owned by the utilities (or retail seller).

(VAMO) Voluntary Allocation and Market Offer: Authorized process for PG&E, SCE, and SDG&E to, at most once per RPS compliance period, allocate a "slice" of their entire PCIA-eligible RPS portfolios to eligible retail sellers and offer to the market any remaining PCIA-eligible RPS portfolio.

Appendix F: California's Load Serving Entities Operating in 2024[67]

Investor-Owned Utilities (IOUs)

- Pacific Gas and Electric Company
- San Diego Gas and Electric
- Southern California Edison

Small and Multi-Jurisdictional Utilities (SMJUs)

- Bear Valley Electric Service
- Liberty Utilities (formerly CalPeco Electric)
- PacifiCorp

Community Choice Aggregators (CCAs)

- Apple Valley Choice Energy
- Ava Community Energy
- Central Coast Community Energy
- Clean Energy Alliance
- Clean Power Alliance of Southern California
- CleanPowerSF
- Desert Community Energy
- Energy for Palmdale's Independent Choice (formerly City of Palmdale)
- King City Community Power
- Lancaster Choice Energy
- Marin Clean Energy
- Orange County Power Authority
- Peninsula Clean Energy
- Pico Rivera Innovative Municipal Energy
- Pioneer Community Energy
- Pomona Choice Energy (City of Pomona)
- Rancho Mirage Energy Authority
- Redwood Coast Energy Authority
- San Diego Community Power
- San Jacinto Power
- San Jose Clean Energy
- Santa Barbara Clean Energy (City of Santa Barbara)
- Silicon Valley Clean Energy
- Sonoma Clean Power Authority
- Valley Clean Energy Alliance

Electric Service Providers (ESPs)

- 3 Phases Renewables
- BP Energy Retail Company (formerly EDF Services)
- Brookfield Renewable Energy Marketing
- Calpine Energy Solutions
- Calpine Power America
- Commercial Energy of California
- Constellation NewEnergy
- NRG (formerly Direct Energy Business)
- Pilot Power Group
- Shell Energy North America
- The Regents of the University of California

67 Excludes Public Owned Utilities (POUs) which are not subject to CPUC jurisdiction.

Appendix G: Voluntary Allocations and Market Offer Contracts

Accepted Voluntary Allocations from IOUs[68]	Market Offer Contracts with IOUs
1. 3 Phases Renewables	1. BP Energy Company
2. Apple Valley Choice Energy	2. Calpine Energy Services
3. City of Palmdale	3. Central Coast Community Energy
4. City of Pomona	4. Clean Power Alliance
5. City of Santa Barbra	5. Clean PowerSF
6. Clean Energy Alliance	6. East Bay Community Energy
7. Clean Power Alliance	7. Lancaster Community Energy
8. Clean PowerSF	8. Pilot Power Group
9. Commercial Energy of California	9. San Diego Community Power
10. Desert Clean Energy	10. San Jose Clean Energy
11. Direct Energy Business	11. Shell Energy North America
12. East Bay Community Energy	
13. Lancaster Choice Energy	
14. Marin Clean Energy	
15. Orange County Power Authority	
16. Pacific Gas and Electric	
17. Pico Rivera Innovative Municipal Energy	
18. Pioneer Community Energy	
19. Rancho Mirage Energy Authority	
20. Redwood Coast Energy Authority	
21. San Diego Community Power	
22. San Diego Gas and Electric	
23. San Jacinto Power	
24. San Jose Community Energy	
25. Shell Energy North America	
26. Silicon Valley Clean Energy	
27. Southern California Edison	

[68] D.22-11-021 at Attachment A.

Appendix H: ERRATA

In the 2024 Padilla Report:

Table 10: Electric Service Providers' 2023 Average Non-RPS Eligible Procurement Expenditures (cents/kWh) 2023 Non-RPS Weighted Average value was incorrectly stated as 7.2. The correct figure is 7.5.

Table 10: Electric Service Providers' 2023 Average Non-RPS Eligible Procurement Expenditure (¢/kWh)

Method	Weighted Average
2023 Non-RPS	7.5
2023 RPS	0.8

Table 11: Electric Service Providers' 2023 RPS Cost Savings Compared to Non-RPS Expenditures ($ million) was incorrectly stated as $49.89. The correct figure is $51.84.

Table 11: Electric Service Providers' 2023 RPS Cost Savings Compared to Non-RPS Energy ($ million)

	Cost Savings Compared to 2023 Average Non-RPS Expenditure (millions)
Electric Service Providers	$51.84
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.	