2026 PADILLA REPORT

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

PUBLISHED JUNE 2026

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: Wind Turbines, Palm Springs, CA

TABLE OF CONTENTS

INDEX OF TABLES & FIGURES

1. Executive Summary

The California Public Utilities Commission (CPUC) issues the 2026 Padilla Report: Costs and Cost Savings for the RPS Program pursuant to California Public Utilities Code § 913.3. This report (referred to as the Padilla Report) summarizes 2025 Renewables Portfolio Standard (RPS) program procurement expenditure and contract price data for California's retail sellers. The 2026 Padilla Report provides a detailed summary of the expenditures of all RPS procurement contracts, including unbundled renewable energy credits for 2025 procurement as well as historical RPS expenditures. The 2026 Padilla Report also includes 2025 executed RPS contract price summaries and historical 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.*[1]
- 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.*[2]

Key Conclusions

- *Decreased per-kilowatt-hour (kWh) cost of RPS procurement:* The investor-owned utilities' (IOUs') 2025 weighted average RPS portfolio cost per kWh decreased 0.7 percent.[3] The IOUs' decrease in average RPS portfolio cost is a continuation of the overall decreasing trend the Commission has been observing over the last ten years of the RPS program.[4] The trend of declining weighted average RPS generation costs may continue in future years as more expensive legacy contracts expire and relatively lower priced contracts become a larger portion of the RPS portfolio mix. For the portion of RPS portfolios that were fixed-price contracts, the 2025 weighted average per-kWh price of fixed cost contracts decreased by 2.4 percent for Community Choice Aggregators (CCAs) and remained steady for Electric Service Providers (ESPs) compared to 2024.
- *Decreased RPS procurement costs:* In 2025, total RPS procurement expenditures spent to meet RPS requirements decreased 6.0 percent from 2024, which was primarily driven by lower overall retail sales due to milder weather and retail sellers' efforts to meet RPS compliance requirements and other policy aims.

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

[2] See CPUC Reports on Utility Cost available at: https://www.cpuc.ca.gov/ab67report.

[3] 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.

[4] While RPS expenditures vary year-over-year, the weighted average RPS expenditure has decreased 29% since 2016. See Figure 1.

- *RPS generation costs in context:* RPS procurement generation expenditures continue to contribute a substantial portion of IOUs' total generation costs. RPS generation costs represented 57.8 percent of the IOUs' generation costs in 2025, while RPS resources were 50.4 percent of overall IOU generation mix. This represents slightly lower IOU generation costs in 2025 while RPS resources were a slightly larger proportion of the IOUs' generation mix (49.2 percent in 2024).
- *2025 conditions appear to have led to a decrease in RPS contract prices:* The average price of RPS contracts executed in 2025 was 6.1 ¢/kWh, compared to the 8.4 ¢/kWh average price for contracts executed in 2024 in real dollars, a 38 percent decrease. The declining costs could contribute to putting downward pressure on electric rates.
- *Benefits of long-term, fixed-price renewable contracts:* While federal policy regarding renewable energy is causing price uncertainty in the renewables market beyond 2025, the impact to ratepayers may be tempered by long-standing, effective direction from the California Public Utilities Commission's RPS Program for the large amount of long-term, fixed-price RPS contracting that California has already completed. This hedging effect against high and volatile prices is one of the original purposes of the RPS program.

2. Background

Renewables Portfolio Standard (RPS) Program

Senate Bill (SB) 836 (Padilla, Chapter 600, Statutes of 2011) codified section 911 of the Public Utilities Code which 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."

The California RPS program was established in 2002 by SB 1078 (Sher, Chapter 516, Statutes of 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.[5]

RPS Procurement Cost Data

The 2025 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 10 ESPs.[6]

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 may 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.

[5] For more information about RPS program requirements and legislative history: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-program-overview.

[6] For a list of California's Active Retail Sellers: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps.

RPS Procurement Contracts

RPS procurement contracts determine which products the retail seller is buying, and because retail sellers employ a variety of RPS procurement practices that lead to preferences for different contract types, the average expenditures amongst retail seller types are not easily comparable. Table 1 provides 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	Retail Seller Preference
"Bundled 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

The annual expenditures for the large IOUs are not directly comparable to the SMJUs, CCAs, and ESPs because their approach to procurement, contracting, and risk management differs. That is, the large IOUs procurement contracts primarily have an "all-in" price that includes procurement of energy, capacity, and RECs as well as curtailment terms which detail actions when it is more economical to curtail energy production rather than bid into the state's energy markets. "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 contract terms, such as those related to facility availability, scheduling, and generation limits. This is different than the SMJUs, which are allowed to entirely procure unbundled RECs to meet their RPS requirements. By comparison, the CCAs and ESPs often have RPS contract portfolios that include a significant portion of short-term contracts for energy and RECs and/or are priced in the manner of "Index + REC."[7] These contracts are distinguished in that payment is based on an Index (e.g. California Independent System Operator (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). While "Index + REC" contracts provide contracting diversity, they can also introduce volatility into RPS pricing.

[7] Index+REC contracts generally define "Index" energy as CAISO's Day Ahead Price when delivered.

3. Renewables Program Costs

This section addresses the costs[8] associated with renewable resource procurement in 2025 on a portfolio basis including:

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

A. RPS Procurement Expenditures

Retail Sellers' RPS expenditures for 2025 are the cumulative costs paid in 2025 pursuant to contracts with operating RPS-eligible facilities. To better compare annual changes in RPS procurement this section also provides expenditures as weighted averages in cents per kWh per retail seller type.

As shown in the below sections, the total real-dollar RPS expenditures[9] for retail sellers decreased and the portfolio per kilowatt-hour cost of 2025 RPS expenditures on a cents per kWh basis remained relatively stable, decreasing slightly. 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.[10]

In 2025, retail sellers experienced slight variations from the overall trends described above, primarily due to their differing procurement approaches to contracting, RPS portfolio positions, and RPS program procurement rules. For instance, as noted in the Background section, 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. Furthermore, the retail sellers may have different RPS contract terms that determine whether the offtaker (i.e., retail seller) or the generator determines the CAISO market bidding strategy and whether resulting market revenues flow to the offtaker or the generator. These differences make some cost comparisons amongst the retail sellers difficult or irresolvable in some instances.

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[8] See *Section 5: RPS Aggregated Contract Prices* for a summary of 2025 RPS contract prices. 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*.

[9] Procurement Expenditures for 2025 include costs for all procurement from online RPS-eligible facilities that generated electricity in 2025. Large IOU procurement expenditures include payments for curtailment volumes which generally increases the unit price of energy reported. See California ISO's Managing Renewable Curtailment page for more information: https://www.caiso.com/about/our-business/managing-the-evolving-grid#:~:text=The%20ISO%27s%20market%20automatically%20reduces,abundant%20supply%20of%20renewable%20generation.

[10] Based on executed RPS contracts, however, as this report is drafted in April 2026, the impact of the federal government's economic policies hamper ability to predict price and cost due to changing tariffs, tax policy, and cost of for private capital.

Large Investor-Owned Utility Procurement Expenditures for 2025

The large IOUs' total annual RPS procurement expenditures in real-dollar value, for bundled IOU electric customers, fell 6.0 percent, from $5.3 billion in 2024 to $5.0 billion in 2025, reflecting slightly lower total RPS generation. In 2025, IOUs procured 47,515 GWh versus 49,693 GWh in 2024, representing a 4.6 percent decrease which may reflect a slight decrease in per capita energy consumption or weather variations causing decreased generation.

Weighted Average Expenditures for Large IOUs

The large IOUs' weighted[11] average RPS procurement expenditures in 2025 were approximately 10.25 ¢/kWh across RPS contracts, excluding any utility-owned generation[12] (UOG). This 2025 average is less than one percent lower than the 10.33 ¢/kWh average in 2024, showing short-term stability in average per-unit portfolio costs. When IOU UOG costs are included, this figure increases slightly given the relatively small amount of generation (approximately 2 percent of total generation) that these UOG facilities presently contribute to the IOU RPS procurement portfolio. Including UOG facilities, the weighted average RPS procurement expenditures for IOUs decreased from 11.08 ¢/kWh in 2024 to 10.56 ¢/kWh in 2025. Detailed IOU 2025 RPS procurement expenditure information is summarized by IOU, technology, and size in Appendix B of this report.

Figure 1 illustrates the large IOUs' weighted average RPS procurement expenditures for renewable energy and associated RECs or bundled[13] renewable energy in ¢/kWh from 2003 through 2025.[14] 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. 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 the project achieves commercial operation and joins the RPS generation portfolio mix.

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[11] The cost of RPS procurement expenditures is weighted based on actual quantities of energy delivered.

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

[13] 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.

[14] The weighted average RPS expenditures on this graph do not include RPS sales. For RPS Sales, refer to Table 2.

Figure 1: Weighted Average RPS Procurement Expenditures of Investor-Owned Utilities' Bundled Renewable Energy from 2003-2025 (Real Dollars)[15]

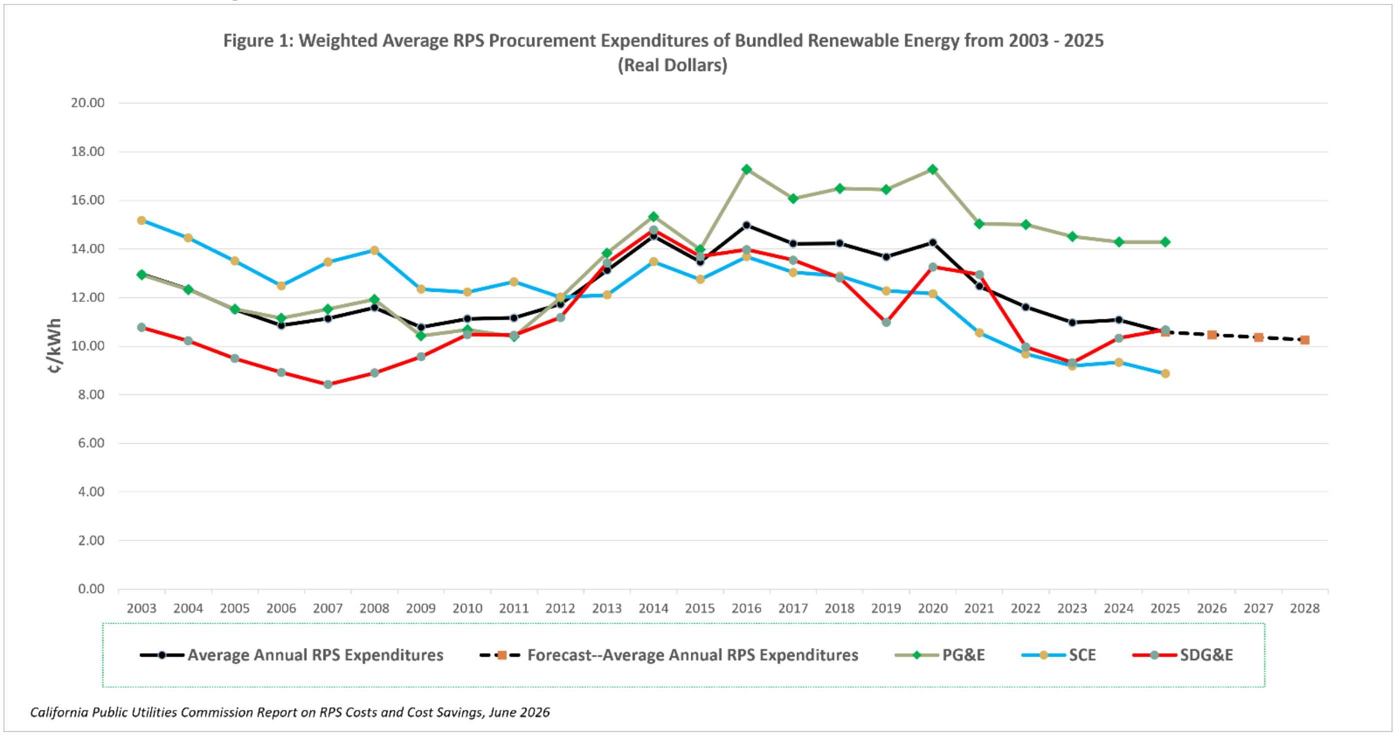
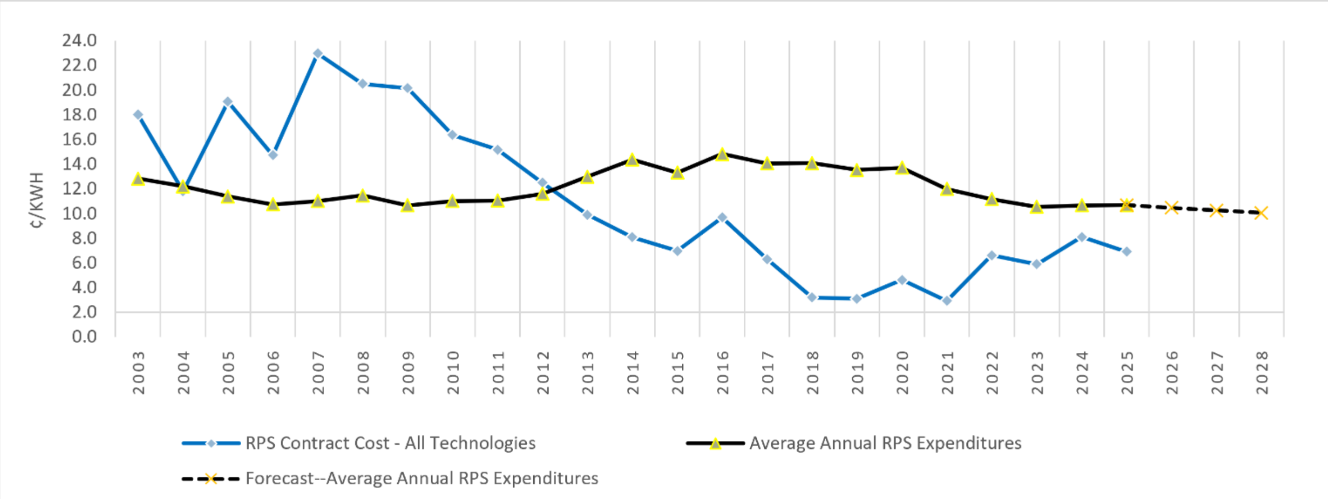


Figure 2 shows the same average annual RPS expenditure data along with RPS contract prices executed from 2019 through 2025 for all retail sellers as well as the IOUs' contract costs executed before 2019. (See Section 5 for details on RPS contract prices). The added price data indicates a lag between 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. It can take several years from contract execution to project build, interconnection, and energy delivery.

[15] The values in this table have been adjusted to 2025 dollars utilizing U.S. Bureau of Labor Statistics inflation statistics.

Figure 2: RPS Program Expenditures and Fixed Contract Costs from 2003-2025[16] (in Real Dollars)



California Public Utilities Commission Report on RPS Costs and Cost Savings, June 2026

Consistent with the decrease in 2025 expenditures, the Commission's near-term forecast of weighted average annual RPS expenditures for the large IOUs' RPS portfolios decreases slightly year-over-year over the next four years, reflecting 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. As previously noted, costs associated with RPS expenditures reflect the conditions under which the contract was signed but delivery of energy under a contract could take place some years later. Therefore, it will still be several years until the most recently executed contracts achieve operation and are reflected in RPS expenditures.

Since 2019, RPS expenditures across all retail sellers has decreased an average of 3.8 percent annually. The approximate impact of this past decrease in contract prices on future expenditures is shown in Figures 1 and 2 as a forecasted decline in average annual RPS expenditures at a rate of 2.0 percent per year between 2025 and 2028. The forecasted 2.0 percent decline in average RPS expenditures is less than the historic 10.3 percent annual decrease in contract prices, signifying the gradual integration of cheaper contracts into the IOUs' portfolios.[17] New contracts are typically cheaper than the existing portfolio average but make up a smaller share of the overall RPS portfolio, which limits the impact on average portfolio costs.

Large IOUs' RPS Sales Solicitations

In addition to procuring, the IOUs also sell RPS energy to optimize their RPS portfolios. In 2025, retail sellers like CCAs and 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 also reducing the large IOUs' customers' costs; RPS sales result

[16] 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 captures price movement specific to a given industry prior to retail level price changes.

[17] See Figure 2.

in revenues that offset total RPS expenditures. These revenues are not reflected in the above data on IOU procurement expenditures. Table 2 provides a summary of the large IOUs' RPS sales in 2025.

Table 2: Large IOUs' 2025 RPS Sales Summary

IOU	RPS Sales (GWh)	RPS Sales Revenue (millions $)
PG&E	6,074	310.1
SCE	5,425	343.9
SDG&E	3,405	228.6
Total	14,904	882.6

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 reducing excess and uneconomic resources from the IOUs' Power Charge Indifference Adjustment[18] (PCIA)-eligible RPS portfolios. Because VAMO transactions can contain contract terms or accounting mechanisms which make them difficult to compare to conventional RPS transactions, 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. These transactions 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. This year's report also does not separate from IOUs' portfolio expenditures the amounts that CCAs and ESPs are responsible for via the PCIA.

Small and Multi-Jurisdictional Investor-Owned Utility Procurement Expenditures for 2025

In 2025, the SMJUs, which include Liberty Utilities (Liberty), PacifiCorp, and Bear Valley Electric Service (BVES), cumulatively spent $35.9 million on RPS procurement as shown in Table 3. The SMJUs' RPS resources include biomass, geothermal, hydroelectric, solar photovoltaic, wind, and unbundled RECs.

Total SMJU Expenditures

In 2025, Liberty and PacifiCorp's expenditures grew by 10.6 percent, from $24 million in 2024 to $26.6 million. The SMJUs' total renewable procurement increased from 695 GWh in 2024 to 771 GWh in 2025, which was the primary driver for increased total expenditures. This resulted in a 2025 RPS percentage of 40.7 percent of their total retail load, which was a 6.8 percent increase from 2024.

[18] See the CPUC's PCIA page for more information: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/power-charge-indifference-adjustment.

Table 3: Small and Multi-Jurisdictional Investor-Owned Utilities' Total RPS Expenditures in 2025

	Liberty	PacifiCorp	Bear Valley Electric Service
Total (millions)	**$15.11**	**$11.49**	**$9.31**

Weighted SMJU Average Expenditures

In 2025, the weighted average RPS procurement expenditure for all Liberty contracts was 5.8 ¢/kWh, 3.2¢/kWh for PacifiCorp, and 6.2 ¢/kWh for BVES. As noted above, though, SMJUs may meet their RPS requirements entirely with unbundled RECs so their procurement expenditures are not directly comparable to those of other retail sellers.

Community Choice Aggregator and Electric Service Provider Procurement Expenditures for 2025

In 2025, there were 25 CCAs and 10 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. The weighted average expenditures and total expenditures for CCAs and ESPs detailed in Table 4 and Table 5 do not incorporate the Index + REC contracts; they only detail costs from fixed-price contracts which include both energy and RECs. Both the CCAs' and the ESPs' total RPS fixed-price contract expenditures increased in 2025 primarily due to the corresponding increased renewable generation procured.[19]

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 2025 for CCAs, and a majority for ESPs, originated from Index + REC contracts. ESP and CCA Index + REC contracting trends are shown in Figure 3 and as noted above, these are not included in their expenditures reported herein.[20] 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, while the price for energy in these contracts can change depending on when electricity is delivered pursuant to the contract.[21] Index + REC contracts differ significantly from "bundled all-in" RPS contracts for energy, capacity, and RECs, where the price is set over the term of the contract. These "bundled all-in" contracts make up the entirety of the IOUs'

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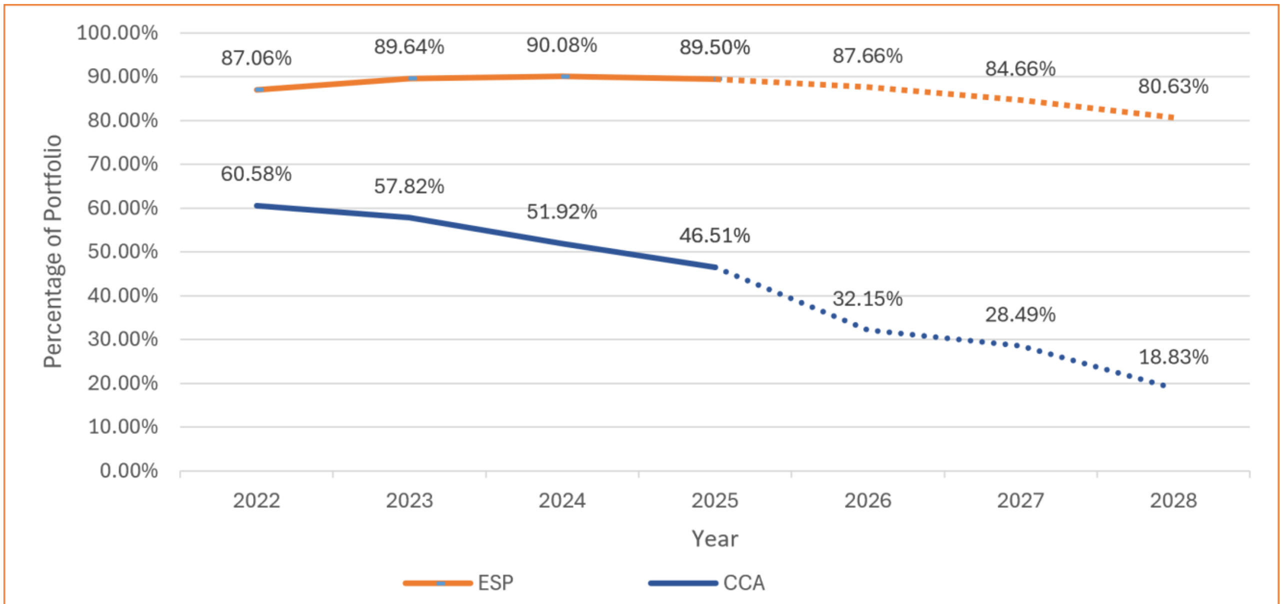
[19] For information regarding CCAs' and ESPs' forecasted RPS compliance, see the 2025 RPS Annual Report to the Legislature at pages 21 and 23: https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/energy/rps/2025/2025-california-renewables-portfolio-standard-rps-annual-report.pdf.

[20] Index + REC contracts generally define "Index" energy as CAISO's Day Ahead Price when delivered.

[21] In the CAISO's most recently released Annual Report on Market Issues and Performance, the average day-ahead energy price was $41/MWh. See CAISO's 2024 Annual Report on Market Issues & Performance, p.3: https://www.caiso.com/documents/2024-annual-report-on-market-issues-and-performance-aug-07-2025.pdf.

RPS portfolios. This difference in contract structure prevents comparison between the contract types. 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 3: Percentage of Index + REC Contracts in CCAs' and ESPs' RPS Portfolios



California Public Utilities Commission Report on RPS Costs and Savings, June 2026

Figure 3 shows the percentage of CCA and ESP RPS contracts with Index + REC price terms. The remaining contracts in their RPS portfolios are fixed-price. See Appendix B for detailed RPS weighted average expenditure data by technology and project size for CCAs and ESPs.

CCAs as a group have been reducing their future reliance on Index + REC contracts by increasing the proportion of fixed-price contracts. The CCAs' shift to more fixed-price contracts is in part due to the 65 percent long-term contracting rule that became effective in 2021.[22] 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 to date 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.

[22] 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. Previously the requirement was a 0.25 percent "minimum quantity".

CCA Procurement Expenditures

CCAs' total annual RPS procurement expenditures for all contracts, including both fixed-price and Index + REC, increased 13.3 percent from $1.5 billion in 2024 to $1.7 billion in 2025, with a 1.2 percent increase in renewables generation from 38,071 GWh in 2024 to 38,515 GWh in 2025.

Table 4: Comparison of CCA RPS Procurement and Procurement Expenditures from Fixed-Price RPS Contracts between 2024 and 2025

	2024	2025
Weighted Average Fixed RPS Contract Expenditures (¢/kWh)	4.2	4.1
Total Fixed RPS Contract Expenditures (millions)	$785.7	$853.5
Total Renewable Energy Delivered from Fixed RPS Contracts (GWh)	18,713	20,803
Average RPS Procurement (% Fixed and Indexed Contracts)[23]	52%	53%

ESPs Procurement Expenditures

The ESPs total annual RPS procurement expenditures for all contracts, both fixed-price and Index + REC, decreased 20.1 percent, from $468 million in 2024, to $374 million in 2025 while total renewables generation increased 18.7 percent, from 11,034 GWh in 2024, to 13,100 GWh in 2025.

Table 5: Comparison of ESP RPS Procurement and Procurement Expenditures from Fixed-Price RPS Contracts between 2024 and 2025

	2024	2025
Weighted Average Fixed RPS Contract Expenditures (¢/kWh)	0.8	0.8
Total Fixed RPS Contract Expenditures (millions)	$6.1	$7.6
Total Renewable Energy Delivered from Fixed RPS Contracts (GWh)	722	901
Average RPS Procurement (% Fixed and Indexed RPS Contracts)[24]	36%	37%

[23] RPS Procurement as a percentage of total load. See Table 4 in the 2025 RPS Annual Report to the Legislature for a more specific discussion on compliance: https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/energy/rps/2025/2025-california-renewables-portfolio-standard-rps-annual-report.pdf.

[24] RPS Procurement as a percentage of total load. See Table 6 in the 2025 RPS Annual Report to the Legislature for a more specific discussion on compliance: https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/energy/rps/2025/2025-california-renewables-portfolio-standard-rps-annual-report.pdf.

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 2025 revenue requirement information for Liberty, BVES, and PacifiCorp is currently confidential pursuant to CPUC confidentiality rules,[25] the CPUC is not able to publicly analyze SMJU costs compared to their revenue requirements for 2025. The 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 2025.[26]

In 2025, RPS procurement expenditures on average were 13.9 percent of the IOUs' total revenue requirements. RPS expenditures typically make up a small portion of an IOU's total revenue requirement 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.[27] This year, the generation component of SDG&E's revenue requirement decreased 60.7 percent, which can be attributable to accounting true-ups and lost Investment Tax Credits (ITCs) from energy storage projects. Additionally, SDG&E's RPS procurement expenditures to total generation revenue requirement appears abnormally large in part because RPS sales and Power Charge Indifference Adjustment funds are not factored into Table 6.

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

[26] For RPS compliance percentage see 2025 RPS Annual Report to Legislature: http://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/energy/rps/2025/2025-california-renewables-portfolio-standard-rps-annual-report.pdf.

[27] See: https://www.cpuc.ca.gov/about-cpuc/divisions/office-of-governmental-affairs for additional cost reports.

Table 6: Comparison of Large Investor-Owned Utilities' RPS Procurement to Revenue Requirements in 2025[28,29]

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	30.0%[30]	$1.95	$4.50	43.31%	$16.79	11.61%
SCE	70.5%	$2.35	$6.12	38.42%	$18.06	13.01%
SDG&E	73.1%	$0.59	$0.31	190.32%	$3.45	17.10%

As retail sellers 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 2025, the large IOUs' average cost of renewable energy was 10.6 ¢/kWh and the average cost of non-RPS energy was 7.8¢/kWh.[31] Using this metric, large IOUs' renewable energy procurement likely added a premium of 2.8 ¢/kWh on average for the renewable energy procured to meet their RPS requirements.[32] 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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[28] Revenue requirement numbers have been taken from the CPUC's *2025 California Electric and Gas Utility Cost Report* pursuant to Public Utilities Code § 913, April 2026.

[29] RPS generation percentages are calculated by dividing the IOUs' RPS generation serving retail load by the IOUs' total generation. These may differ from RPS compliance percentages; see the CPUC's *2025 RPS Annual Report to the Legislature* for discussion on retail seller compliance: http://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/energy/rps/2025/2025-california-renewables-portfolio-standard-rps-annual-report.pdf.

[30] In 2025, PG&E utilized excess procurement ("banked" RECs) to partially satisfy their annual RPS compliance obligations, leading to a relatively lower annual RPS procurement proportion.

[31] See Table 7.

[32] The average RPS cost savings compared to non-RPS energy on a kilowatt-hour basis is represented by the following equation: 10.6 *¢/kWh (RPS Energy) – 7.8 ¢/kWh (Non-RPS Energy) = 2.3 ¢/kWh.*

4. Renewables Program Cost Premiums and/or Savings

Pursuant to §913.3(c) this section addresses the cost premiums and savings associated with the large IOUs', SMJUs', CCAs', and ESPs' procurement of renewable resources in 2025 in meeting the RPS program requirements.

In determining the cost savings for this report, the utilities' 2025 RPS procurement costs are compared to non-RPS procurement costs. This comparison likely understates non-RPS procurement costs because 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.[33]

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.
- The costs of other attributes, such as Resource Adequacy, while not included in this analysis, 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.

Consequently, there is no perfect counterfactual method 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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[33] R-Street research "If Renewable Energy Is Cheaper, Then Why Don't We Use It Exclusively?", January 10, 2025, Rossetti, Chandler: http://www.rstreet.org/commentary/low-energy-fridays-if-renewable-energy-is-cheaper-then-why-dont-we-use-it-exclusively/.

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

In 2025, the large IOUs' average annual RPS procurement expenditures represented a weighted average of 2.8 ¢/kWh cost premium versus their average non-RPS procurement expenditures (Table 7). Individually, PG&E and SCE both paid premiums for RPS procurement: 5.3 ¢/kWh and 6.2 ¢/kWh, respectively. Conversely, SDG&E paid a discount for RPS energy—compared to non-RPS energy—of 12.1 ¢/kWh. This pattern is in line with the most recent years, with average non-RPS prices declining for PG&E and SCE while rising for SDG&E. Weighted average RPS expenditures in 2025 were 0.9 percent higher than 2024 expenditures on a cents per kWh basis, which is less than the 5 percent rise from 2023 to 2024.

Table 7: Large Investor-Owned Utilities' 2025 Average RPS and Non-RPS Eligible Procurement Expenditure[34] (¢/kWh)

Method	PG&E	SCE	SDG&E	Weighted Average	Historical Average (2018-2025)
2025 Non-RPS	8.6	2.6	22.8	7.8	7.1-11.6
2025 RPS	13.9	8.8	10.7	10.6	10.0-10.6[35]

Based on total amounts 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, respectively.

Table 8: Large Investor-Owned Utilities' 2025 RPS Cost Savings: Non-RPS Eligible Comparison

Cost Savings Compared to 2025 Average Non-RPS Expenditure (millions)	
PG&E	($713.92)
SCE	($1,530.23)
SDG&E	$944.08
Cost savings are displayed as positive figures while cost premiums are displayed as (negative) figures.	

[34] Derived from responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted January 30, 2026, and CPUC's 2025 AB 67 report, to be published May 2026.

[35] The IOUs' RPS portfolios include both high-priced legacy contracts as well as more recent contracts with much lower prices as described throughout. As newer RPS contracts come online and legacy contracts expire, the IOUs' weighted average price per kilowatt-hour is expected to decrease.

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

In 2025, 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, and this program difference may drive some differences in procurement. Additionally, SMJUs' RPS contracting started later than IOU contracting, thus their 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 SMJU RPS portfolios contain only contracts delivering both REC and energy and any REC-only contracts are excluded so that procurement expenditures between RPS and non-RPS are comparable. Bear Valley Electric Service was the only SMJU which reported a cost premium for RPS procurement, at 0.8 ¢/kWh; Liberty and PacifiCorp reported cost savings of 0.9 ¢/kWh and 2.0 ¢/kWh for RPS procurement, respectively.

Table 9: Small and Multi-Jurisdictional Investor-Owned Utilities' 2025 Average RPS and Non-RPS Eligible Procurement Expenditure (¢/kWh)

Method	Liberty	PacifiCorp	Bear Valley Electric Service	Weighted Average
2025 Non-RPS	7.8	6.1	7.8	7.2
2025 RPS	6.9	4.0	8.6	5.9

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):

Table 10: Small and Multi-Jurisdictional Investor-Owned Utilities' 2025 RPS Cost Savings: Non-RPS Eligible Comparison[36]

Cost Savings Compared to 2025 Average Non-RPS Expenditure (millions)	
Liberty	$1.93
PacifiCorp	$5.52
Bear Valley Electric Service	$(0.82)
Cost savings are displayed as positive figures while cost premiums are displayed as (negative) figures.	

[36] Cost savings or premiums are calculated by multiplying each SMJU's average 2025 non-RPS eligible expenditure (cents/kWh) (Table 10) by its total volume of RPS procurement (kWh) in 2025 then subtracting that value from the SMJUs' 2025 RPS procurement expenditure ($) (Table 3).

C. CCAs' and ESPs' Cost Premiums / Savings

In 2025, the RPS procurement expenditure for CCAs and ESPs represented a 2.0 ¢/kWh and 3.4 ¢/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 of those contracts, most of the ESPs' contracts (see Figure 3) are not incorporated in the below 2025 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: CCAs' and ESPs' 2025 Average RPS, Non-RPS Eligible Procurement Expenditures and RPS Cost Savings Compared to Non-RPS Energy[37] (¢/kWh)

	2025 non-RPS Weighted Average (¢/kWh)	2025 RPS Weighted Average (¢/kWh)	Cost Savings Compared to 2025 Average Non-RPS Expenditure (million)
Community Choice Aggregators	6.1	4.1	$421.2
Electric Service Providers	4.2	0.8	$30.2

[37] Cost savings or premiums are calculated by multiplying CCAs' average 2025 non-RPS eligible expenditure (Table 10) by volume of RPS procurement in 2025 (excluding Index + REC deliveries) then subtracting that value from the CCAs' 2025 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. The RPS contract price is the agreed upon 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 2025 RPS contract prices from contracts executed by retail sellers in 2025. In addition to contracts executed in 2025, this report also includes historical prices which have been adjusted in real dollars. Specifically, the CPUC examined the IOUs', CCAs', and ESPs' 2019 - 2025 executed contract prices.[38] Moreover, the CPUC also reviewed IOUs' RPS contracts executed between 2003 and 2018 to provide historic contract cost trends.[39] To remove non-representational trends, contracts with a nameplate capacity of 3 MW or less were not included in Figure 5.[40]

RPS Contract Prices for Resources Greater than 3 MW

Figure 4, below, shows that RPS contract prices, in real-dollar value, decreased an average of 7.1 percent annually between 2007 and 2025.

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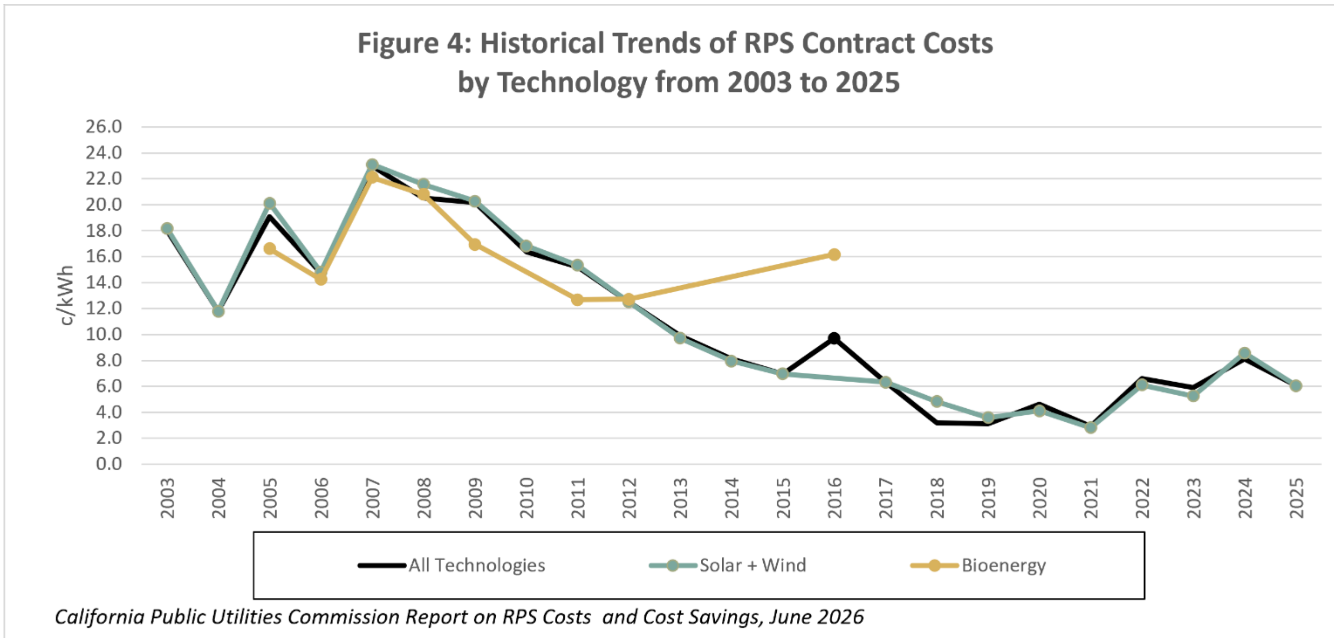
[38] 2019 through 2025 contract price data for IOUs, CCAs and ESPs were obtained through a joint data request pursuant to Pub. Util. Code §913.3 and the *Power Charge Indifference Adjustment (PCIA)* proceeding. Contract data for 2003-2018 was self-reported by the IOUs through the CPUC's RPS Executed Projects Database.

[39] *Ibid.*

[40] 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 4: Historical Trends of RPS Contract Costs by Technology from 2003 to 2025



Note: The "All Technologies" line includes bioenergy, solar, wind, geothermal, and hybrid resources. Solar + wind and bioenergy are shown separately for comparison. The bioenergy line does not extend further due to the lack of new contracting with that type of technology. Other technologies, including geothermal and hybrid resources, are included in the all-technologies line, but they are not broken out because there are too few contracts to maintain confidentiality.

The historic contract price trends for the RPS program seen in Figure 4 show that executed contract prices for RPS-eligible resources peaked in 2007 and have generally decreased since. The average price of IOU, CCA, and ESP RPS contracts executed in 2025 that were greater than 3.0 MW provides some relief from the recent trend of increasing contract prices. Specifically, the average price in 2025 was 6.1¢/kWh compared to 8.1 ¢/kWh in real-dollar value in 2024, a 32.8 percent decrease. See Appendix C for 2025 contract price data.

<u>RPS Contract Prices for Resources 3 MW and Less</u>

RPS resources with a nameplate capacity of 3.0 MW or less are not included in Figure 4. Accordingly, the large IOU's contracts signed in 2025 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 based on energy deliveries: 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 the CPUC. See Table 12 for the 2025 offered ReMAT prices. No ReMAT contracts were executed in 2025.

Table 12: 2025 ReMAT Prices by Product Category

ReMAT Product Category	2025 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 established by Senate Bill 1122 (Rubio, Chapter 612, Statutes of 2012) that allocates procurement to the discrete bioenergy categories of Biogas, Dairy/Agriculture, and Sustainable Forest Management. The program was implemented in 2014 and uses a standard contract and a market-based mechanism to arrive at the offered program contract price. Table 13 shows the 2025 offered BioMAT contract prices. One BioMAT contract was executed in 2025.

Table 13: 2025 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. In November 2023, CCAs were authorized to join the BioMAT program by Assembly Bill 843 (Aguiar-Curry, Chapter 234, Statutes of 2021), and executed one BioMAT contract in 2025. During 2025, the CCAs did not execute any other new-build RPS-eligible facilities with 3.0 MW or less capacity.[41]

Bioenergy Renewable Auction Mechanism (BioRAM) Contracts

[41] This data was obtained through the joint RPS-PCIA Semi-Annual Data Report, submitted January 30, 2026.

Pursuant to the Governor Brown's 2015 Emergency Order Addressing Tree Mortality[42], SB 859 (Committee on Budget and Fiscal Review, Chapter 368, Statutes of 2016), and SB 901 (Dodd, Chapter 626, Statutes of 2018), 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 and extended contracts with seven biomass facilities to meet their BioRAM procurement requirements.[43]

In 2025, the existing six biomass facilities contracted totaled 154 MW and have an average contract price of 12.0 ¢/kWh. No new BioRAM contracts were executed in 2025.

[42] See: Executive Order B-42-17

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

6. Appendices

Appendix A: CPUC RPS Activities and Milestones

January 2025	▪ IOUs, SMJUs, CCAs, and ESPs filed Final 2024 RPS Procurement Plans.
February 2025	▪ CPUC issued response to Governor Executive Order N-5-24.
March 2025	▪ CPUC approved Resolution E-5345 approving PG&E RPS eligible, Mid-Term Reliability Contracts. ▪ CPUC approved Resolution E-5375 denying PG&E request to approve of sale of 2025-Delivery Renewable Energy Credits to NRG Business Marketing, LLC.
April 2025	▪ CPUC issued the Assigned Commissioner and Assigned Administrative Law Judge's Ruling issued identifying issues and a schedule of review for the 2025 RPS Procurement Plans. ▪ CPUC approved Resolution E-5376 amending the BioRAM Program pursuant to (AB) 2750. ▪ CPUC issued Reliable and Clean Power Procurement Program Staff Proposal.
May 2025	▪ Staff conducted the 2025 RPS Procurement Plans Webinar.
June 2025	▪ CPUC approved Resolution E-5392 adopting 2025 updated administratively set fixed avoided-cost rates for the ReMAT program. ▪ CPUC issued the 2025 Padilla Report on Costs and Cost Savings for the RPS Program to the Legislature, https://www.cpuc.ca.gov/RPS_Reports_Data/.
July 2025	▪ Staff conducted the 2025 RPS annual Compliance Reports Webinar. ▪ IOUs, SMJUs, CCAs, and ESPs submitted Draft 2025 RPS Procurement Plans. ▪ CPUC approved Central Coast Community Energy's BioMAT contract.
August 2025	▪ IOUs, CCAs, and ESPs submitted annual RPS Compliance Reports. ▪ CPUC adopted D.25-08-009, rejecting the IOUs' proposals for preapproved short-term RPS Transactions.
September 2025	▪ CPUC adopted D.25-09-012 approving SCE's sale of RPS-eligible Hydroelectric Power Plants to San Bernardino Valley Municipal Water District.
October 2025	▪ CPUC issued the Assigned Commissioner's Scoping Memo and Ruling issued for Integrated Resources Planning proceeding (R.25-06-019)
November 2025	▪ CPUC approved Resolution E-5428 which grants Southern California Edison request for approval of Mid-Term Reliability Resource Contracts and one Amendment.
December 2025	▪ CPUC issued the 2025 Annual RPS Report to the Legislature. ▪ Energy Division issued SB 155 RPS Compliance Risk letters ▪ CPUC adopted D.25-12-024 approving Bear Valley Electric Services request for approval of utility-owned solar photovoltaic and storage facility. ▪ BioMAT program closed. ▪ D.25-12-025 adopted, with modifications, the draft 2025 RPS Procurement Plans of 41 retail sellers.

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 2025.[44] Tables B-2 and B-3 show the weighted average RPS procurement expenditures for 2025 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.[45] 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 2025.
- Procurement expenditures represent averages weighted by capacity procured on a per kilowatt-hour basis. All figures are in 2025 dollars.

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[44] 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 2025 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.

[45] See historical trend of RPS contract costs in Figure 4.

Table B-1. Weighted Average RPS Procurement Expenditures for IOUs in 2025 (¢/kWh)

	PG&E	SCE	SDG&E	Weighted Avg.
Biogas				
0-3 MW	Only 2 Contracts	11.2	Only 2 Contracts	11.2
+3-20 MW	Only 2 Contracts	Only 1 Contract	Only 1 Contract	10.9
Biogas Total	**11.6**	**11.1**	**8.2**	**11.0**
Biomass				
0-3 MW	19.3	-	-	19.3
+3-20 MW	-	Only 1 Contract	-	-
+20-50 MW	11.2	Only 1 Contract	Only 1 Contract	11.1
+50-200 MW	Only 1 Contract	-	-	-
Biomass Total	**10.9**	**-**	**Only 1 Contract**	**11.1**
Geothermal				
+3-20 MW	Only 2 Contracts	Only 1 Contract	-	8.5
+20-50 MW	-	Only 2 Contracts	-	-
+50-200 MW	-	Only 1 Contract	-	-
+200 MW	-	Only 1 Contract	-	-
Geothermal Total	**Only 2 Contracts**	**6.9**	**-**	**8.2**
Small Hydro				
0-3 MW	12.9	11.9	6.1	12.5
+3-20 MW	5.0	7.9	-	7.1
+20-50 MW	Only 2 Contracts	Only 1 Contract	-	7.2
Small Hydro Total	**10.7**	**6.4**	**6.1**	**8.4**
Solar Photovoltaic				
0-3 MW	9.8	12.3	12.1	11.6
+3-20 MW	10.3	9.1	9.3	9.6
+20-50 MW	15.0	Only 1 Contract	Only 2 Contracts	14.8
+50-200 MW	12.1	5.8	13.0	8.8
+200 MW	18.7	11.9	-	14.3
Solar Photovoltaic Total	**14.8**	**9.0**	**12.7**	**11.1**
Solar Thermal				
+50-200 MW	Only 2 Contracts	Only 1 Contract	-	16.5
+200 MW	Only 2 Contracts	-	-	-
Solar Thermal Total	**19.7**	**-**	**-**	**19.2**
Wind				
0-3 MW	-	Only 2 Contracts	-	-
+3-20 MW	Only 2 Contracts	Only 2 Contracts	Only 2 Contracts	6.3
+20-50 MW	Only 1 Contract	Only 2 Contracts	Only 1 Contract	9.2
+50-200 MW	9.0	9.6	7.5	9.1
+200 MW	-	8.4	Only 1 Contract	10.4
Wind Total	**8.9**	**9.2**	**7.9**	**9.2**
Various				
0-3 MW	**-**	Only 2 Contracts	**-**	**Only 2 Contracts**
Various Total	**-**	Only 2 Contracts	**-**	**Only 2 Contracts**
UOG Small Hydro				
0-3 MW	145.1	-	-	145.1
+3-20 MW	35.7	-	-	35.7
+20-50 MW	Only 1 Contract	-	-	Only 1 Contract
UOG Small Hydro Total	**35.2**	**-**	**-**	**35.2**
UOG Solar Photovoltaic				
0-3 MW	Only 1 Contract	-	-	-
+3-20 MW	31.9	-	-	31.9
UOG Solar Photovoltaic Total	**32.0**	**-**	**-**	**32.0**
Weighted Avg. All Resources	**13.9**	**8.8**	**10.7**	**10.6**[46]

46 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 2025 (¢/kWh)

	All Contract Weighted Average[47]	Index +REC Weighted Average
Biogas		
0-3 MW	3.6	3.8
3-20 MW	Only 2 Contracts	-
Biogas Total	**4.4**	**3.8**
Biomass		
0-3 MW	-	3.3
3-20 MW	-	-
20-50 MW	Only 1 Contract	Only 2 Contracts
Biomass Total	**Only 1 Contract**	**2.5**
Geothermal		
0-3 MW	Only 2 Contracts	-
3-20 MW	7.3	-
20-50 MW	6.4	-
50-200 MW	Only 1 Contract	-
Geothermal Total	**6.5**	**-**
Small Hydro		
0-3 MW	6.2	Only 2 Contracts
3-20 MW	Only 2 Contracts	Only 1 Contract
20-50 MW	Only 2 Contracts	-
Small Hydro Total	**5.4**	**1.6**
Solar Photovoltaic		
0-3 MW	5.7	4.9
3-20 MW	8.4	-
20-50 MW	3.6	-
50-200 MW	3.0	1.1
+200 MW	3.3	-
Solar Photovoltaic Total	**3.3**	**2.9**
Various/REC-Only[48]		
0-3 MW	3.0	4.9
3- 20 MW	-	-
20 -50 MW	-	4.4
50-200 MW	-	3.1
+200 MW	-	Only 2 Contracts
Various/REC-Only Total	3.0	4.6
Wind		
0-3 MW	Only 1 Contract	5.6
3-20MW	5.3	1.3
20-50 MW	4.9	Only 2 Contracts
50-200 MW	4.7	-
+200 MW	4.2	-
Wind Total	**4.6**	**4.6**
Weighted Average of All Resources	**4.1**	**3.6**[49]

[47] Totals for each technology type exclude expenditures from Index + REC contracts.
[48] 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 a retail seller 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.
[49] Excludes Various/REC-only expenditures.

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

(Bundled Energy, Index + REC, and REC-Only Transactions) for 2025 (¢/kWh)

	All Contract Weighted Average	Index + REC Weighted Average
Biogas		
0-3 MW	Only 2 Contracts	4.0
3-20 MW	-	Only 1 Contract
Biogas Total	**Only 2 Contracts**	**3.4**
Biomass		
0-3 MW	-	Only 2 Contracts
Biomass Total	**-**	**Only 2 Contracts**
Geothermal		
0-3 MW	-	
Geothermal Total	**-**	**-**
Small Hydro		
0-3 MW	Only 1 Contract	Only 2 Contracts
Small Hydro Total	**Only 1 Contract**	**Only 2 Contracts**
Solar Photovoltaic		
0-3 MW	Only 2 Contracts	3.2
3-20 MW	Only 1 Contract	-
20-50 MW	-	Only 2 Contracts
50-200 MW	-	Only 2 Contracts
+200 MW	-	2.9
Solar Photovoltaic Total	1.1	**2.9**
Wind		
0-3 MW	Only 1 Contract	3.8
20-50 MW	-	Only 1 Contract
50-200 MW	-	Only 1 Contract
Wind Total	**Only 1 Contract**	**3.8**
Various/REC Only		
0-3 MW	0.8	3.3
3-20 MW	-	Only 1 Contract
20-50 MW	-	Only 1 Contract
50-200MW	-	Only 1 Contract
+200 MW	-	Only 2 Contracts
Various/REC-Only Total	**0.8**	**3.2**
Weighted Average of All Resources	**0.8**	**3.0**[50]

[50] Excludes Various/REC-Only expenditures.

Appendix C: 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 2025. Tables C-2 and C-3 show the weighted average contract prices for the CCA and ESP RPS contracts executed in 2025.

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 2025 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 2025 for IOUs (¢/kWh)

Approved in 2025 for IOUs (¢/kWh)	PG&E	SCE	SDG&E	Total
Biomass				
0-3 MW	Only 1 Contract	-	-	-
Biomass Total	**Only 1 Contract**	**-**	**-**	**-**
Geothermal				
3-20- MW	Only 1 Contract	-	-	-
Small Hydro Total	**Only 1 Contract**	**-**	**-**	**-**
Solar Photovoltaic				
0-3 MW	6.7	Only 2 Contracts	-	6.9
+3-20 MW	Only 1 Contract	Only 2 Contracts	-	5.2
+20-50 MW	-	-	-	-
+50-200 MW	-	6.0	-	6.0
+200 MW	-	4.8	-	4.8
Solar Photovoltaic Total	**6.7**	**5.6**	**-**	**5.9**
Average of All Resources	**9.2**	**5.6**	**-**	**6.8**

Table C-2. Average Contract Price of All Renewable Energy Contracts Executed in 2025 With Anticipated Delivery in Future Years for CCAs (¢/kWh) Including Index + REC contracts

Executed in 2025 for CCAs (¢/kWh)	Total	REC
Biomass		
0-3 MW	Only 1 Contract	-
Index +REC (excludes cost of energy index)		-
Biomass Total	**Only 1 Contract**	**-**
Geothermal		
3-20 MW	Only 2 Contracts	-
Index +REC (excludes cost of energy index)	-	-
Geothermal Total	**Only 2 Contracts**	**-**
Hybrid		
20-50 MW	-	-
50-200 MW	Only 1 Contract	-
Index + REC (excludes cost of energy index)	-	-
Hybrid Total	**Only 1 Contract**	**-**
Small Hydro		
0-3 MW	Only 1 Contract	-
3-20 MW	-	-
Index + REC (excludes cost of energy index)	-	-
Small Hydro Total	**Only 1 Contract**	**-**
Solar Photovoltaic		
0-3 MW	15.3	-
3-20 MW	10.3	-
20-50 MW	5.0	-
50-200 MW	5.0	-
+200 MW	Only 1 Contract	-
Index + REC (excludes cost of energy index)	-	-
Solar Photovoltaic Total	**8.4**	**-**
Various/REC-Only[51]		
0-3 MW	-	-
20-50 MW	-	1.8
50-200 MW	-	3.0
Index + REC (excludes cost of energy index)	-	2.4
REC-Only	-	-
Various/REC Only Total	**-**	**2.4**
Wind		
3-20 MW	8.4	-
20-50 MW	8.7	-
50-200 MW	7.9	-
+200 MW	-	-
Index + REC (excludes cost of energy index)	-	-
Wind Total	**8.2**	**-**
Average of All Resources	**8.7**	**N/A**[52,53]

[51] The "Various" technology type indicates contracts where the technology type is not known by the buyer until the energy and RECs are delivered. This arrangement occurs when an LSE procures from multiple facilities in a seller's portfolio.

[52] Excludes Various/REC-Only contracts.

[53] Only Various/REC only contract for 2025.

Table C-3. Average Contract Price of All Renewable Energy Contracts Executed in 2025 With Anticipated Delivery in Future Years for ESPs Including Index + REC Contracts (¢/kWh)

Executed in 2025 for ESPs (¢/kWh)	Total	REC
Biogas		
Index + REC (excludes cost of energy index)	-	-
Biogas Total	**-**	**-**
Geothermal		
0-3 MW	Only 1 Contract	-
Index + REC (excludes cost of energy index)	-	-
Geothermal Total	**Only 1 Contract**	**-**
Solar PV		
0-3 MW	Only 1 Contract	-
Index +REC (excludes cost of energy index)	-	-
Solar PV Total	**Only 1 Contract**	**-**
Various/REC-Only[54]		
0-3 MW	1.5	**-**
Index + REC (excludes cost of energy index)	**-**	1.3
REC-Only	**-**	Only 2 Contracts
Various/REC Only Total	**1.5**	**1.1**
Wind		
0 -3 MW	Only 1 Contract	-
20-50 MW	Only 1 Contract	-
50-200 MW	Only 1 Contracts	-
Index + REC (excludes cost of energy index)	-	-
Wind Total	**3.9**	**-**
Average of All Resources	**2.0**	**N/A**[55,56]

[54] The "Various" technology type indicates contracts where the technology type is not known to the buyer until the energy and RECs are delivered. This arrangement occurs when an LSE procures from multiple facilities in a seller's portfolio.

[55] Excludes Various/REC-Only contracts.

[56] Only Various/REC only contracts for 2025.

Appendix D – Glossary of Acronyms and Terms

Bundled Renewable Energy: renewable energy that is sold with its associated renewable energy credit.

(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.

(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. There are 25 active CCAs as of 2025.

(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 their unregulated affiliates and subsidiaries. There are 10 active ESPs as of 2025.

(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.

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 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 Publicly Owned Utilities.

(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.

(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.

(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.

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

RPS contract price is the agreed amount to be paid ($/MWh or $/REC) for the RPS-eligible product pursuant to the executed contract

RPS Expenditures are the costs paid pursuant to the cumulative portfolio of delivering RPS contracts with operating RPS-eligible facilities. Reported as total portfolio costs ($) or weighted-averaged (cents/kWh).

(SMJU) Small & Multi-Jurisdictional Utility: Investor-owned utilities that are small & multi-jurisdictional subject to different rules per PUC § 399.17 & § 399.18. There were 3 SMJUs in 2025.

Unbundled RECs or REC-only transactions: RECs are sold separately from the underlying renewable energy generation.