2024 PADILLA REPORT

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

PUBLISHED MAY 2024

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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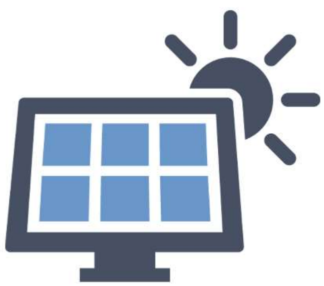
1. Executive Summary

In compliance with Public Utilities Code § 913.3,[1] this report summarizes 2023 Renewables Portfolio Standard (RPS) program procurement expenditure and contract cost data. In 2023, total renewables generation declined just slightly across load-serving entities while RPS contract costs declined more materially in real-dollar value from 2022 costs.[2] The net result of this is that RPS procurement expenditures declined on a per GWh basis. These overall expenditures per GWh are expected to continue to generally trend downward because RPS prices have been declining, supporting one of the original purposes of the RPS program, which was to be a cost-effective physical hedge against high and volatile fuel prices such as for natural gas.

Key conclusions from this report include the following:



- The large investor-owned utilities' (IOUs) - defined in this report as Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E), total annual RPS procurement expenditures decreased from $5.2 billion in 2022 to $5.0 billion in 2023 while total renewables generation also decreased from 49,665 GWh to 48,662 GWh. The decrease in generation is a result of load departure to Community Choice Aggregators (CCAs) and older facilities rolling off contract, resulting in a 2023 RPS percentage of retail load of 47.3 percent. The decrease in IOUs total RPS costs was the result of this reduction in renewable generation procured and a modest decline in IOUs' RPS costs (from 10.5 to 10.0 cents per kWh).
- The average cost of IOU non-RPS energy in 2023 was 8.3 ¢/kWh, which represents a 1.7 ¢/kWh cost premium for RPS procurement expenditures compared to non-RPS procurement expenditures.
- While the IOUs 2023 RPS-eligible costs were a slightly larger portion of the total expenditures spent on resources, they continue to track with the portion of IOUs' retail load met with RPS-eligible resources. For example, 47.3 percent of load was

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

[2] 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.

met with RPS-eligible resources and expenditures on renewable generation was 52.7 percent of the IOUs' total generation costs. In contrast, in 2023 non-RPS costs varied substantially from 2022. suggesting renewable sources and generation may be serving as an effective price hedge.

- For small and multi-jurisdictional utilities (SMJUs), total annual RPS procurement expenditures increased from $16.3 million in 2022 to $18.3 million in 2023 while total renewables generation increased from 477 GWh to 495 GWh, resulting in a 2023 RPS percentage of retail load of 26.8 percent. This reflects a slight increase in renewables expenditures on a per GWh basis.

- Community choice aggregators' (CCAs') total annual RPS procurement expenditures for all contracts decreased from $810 million in 2022 to $806 million in 2023, and renewables generation also decreased from 12,357 GWh in 2022 to 11,639 GWh in 2023.[3] This is more a reflection of declining contract prices and the shifting from Fixed price contracts to Index plus REC than a decrease in energy usage.
- Electric Service Providers' (ESPs') total annual RPS procurement expenditures for all contracts increased from $92 million in 2022 to $279.0 million in 2023, and total renewables generation increased from 7,191 GWh in 2022 to 8,414 GWh in 2023. The result was an increase of the RPS-generated energy portion as a total of the retail load from 47 percent in 2022 to 60 percent.

- The average price of RPS contracts for all retail sellers that were executed in 2023 were approximately 5.8 ¢/kWh, slightly lower than the 6.2 ¢/kWh average price in 2022 (in real dollars). Cost reduction drivers may include availability of federal incentives and the alleviation of certain supply chain constraints. .

[3] See Table 3: Comparison of Community Choice Aggregator RPS Procurement and Procurement Expenditures between 2022 and 2023 at 11.

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."[4]

The California RPS program was established in 2002 by Senate Bill (SB) 1078 (Sher, 2002) with the initial requirement that 20% 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% mandate be met by 2010. In April 2011, SB 2 (1X) (Simitian, 2011) codified a 33% RPS requirement to be achieved by 2020. In 2015, SB 350 (de León, 2015) mandated a 50% RPS by December 31, 2030. On September 10, 2018, SB 100 (de León, 2018) was signed into law, which further increased the RPS to 60% by December 31, 2030, with interim targets of 44% by December 31, 2024, and 52% by December 31, 2027, and sets the goal for all retail electricity sales to come from zero carbon resources by 2045.[5]

The 2023 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 SMJUs; 25 CCAs; and 12 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 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 in a later year.[7]

The annual expenditures for the IOUs may not be directly comparable to the SMJUs, CCAs, and ESPs because their approach to procurement and contracting differs from the other CPUC jurisdictional retail sellers. That is, the IOUs procurement contracts primarily have an "all-in" price that includes procurement of energy, capacity, and renewable energy credits (RECs) and curtailment expenditure

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[4] 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.

[5] 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.

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

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

terms. This is different than the SMJUs, which are allowed to entirely procure unbundled RECs to meet their RPS requirements. By comparison, the CCAs may have short-term contracts that include energy and RECs and/or are priced in the manner of "Index + REC." Finally, ESPs traditionally have procured almost exclusively through short-term contracts energy and REC and/or "Index + REC" contracts. It is worth noting that SB 350's 65 percent RPS long-term procurement requirement begins in Compliance Period 2021-2024, which may result in a decline in this type of short-term contracting by the CCAs and ESPs.

3. Renewables Program Costs

This section addresses the costs associated with renewable resource procurement in 2023, consistent with the requirements of § 913.3(a)(1)-(2) and (b).

Section 913.3(a)(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.

Section 913.3(a)(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.

Section 913.3(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.

The 2023 costs and cost savings discussed in this section include:

- RPS Procurement Expenditures
- RPS Aggregated Contract Prices
- Comparison of RPS Procurement Expenditures with Revenue Requirements (for IOUs only)

A. RPS Procurement Expenditures

This section provides information on 2023 weighted average expenditures and total RPS procurement expenditures for all categories of retail sellers. Generally, the real-dollar value of RPS expenditures[8] for retail sellers have trended down on a per GWh basis and this trend is expected to continue.[9]

Investor-Owned Utility Procurement Expenditures for 2023

The IOUs' total annual RPS procurement expenditures in real-dollar value stayed relatively stable just declining slightly from $5.2 billion in 2022 to $5.0 billion in 2023 primarily reflecting load departure to CCAs. This reflects a small real-dollar value decrease in renewables expenditures on a per GWh basis. Aside from the retail load shift to CCAs, older contracts entered at higher prices continue to roll off and are replaced with lower priced contracts. Compiled, detailed IOU 2023 RPS procurement information is summarized in Appendix B of this report, expressed as weighted averages for RPS procurement expenditures in cents per kilowatt-hour (¢/kWh) categorized by IOU, technology, and size.[10]

Weighted Average Expenditures for IOUs

Based on the compiled 2023 data, weighted average RPS procurement expenditures were approximately 10.0 ¢/kWh across all IOU RPS contracts, excluding REC-only contracts and renewable utility-owned generation (UOG) costs. This 2023 average is slightly lower in real-dollar value than the 10.2 ¢/kWh average in 2022.

Figure 1 below illustrates the weighted average RPS procurement expenditures for renewable energy and associated RECs or bundled renewable energy in ¢/kWh for each of the IOUs from 2003 through 2023.[11] The changes in weighted average expenditures over time for each IOU are similar, and the key factors driving the cost differences between the IOUs are resource mixes and contract vintages.

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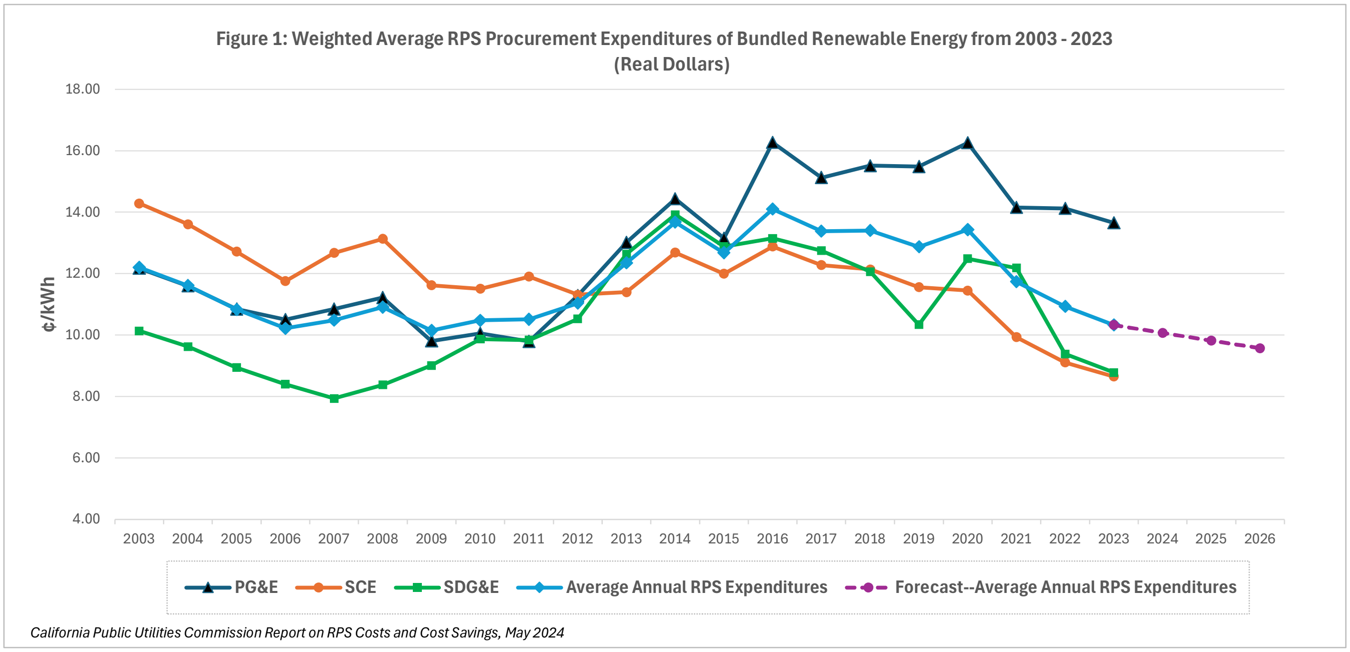
[8] Procurement Expenditures for 2023 include costs for all procurement from online RPS-eligible facilities that generated electricity in 2023. IOU procurement expenditures include payments for curtailment volumes which generally increases the unit price of energy reported. See California ISO's Managing Oversupply page for more information on curtailment: http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.

[9] See also Lazard, Levelized Cost of Energy Analysis – Version 15.0 (October 2021) at 13: Certain renewable energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the continued cost decline of renewable energy generation technologies is the ability of technological development and industry scale to continue lowering operating expenses and capital costs for renewable energy generation technology.

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

[11] Bundled renewable energy is defined as renewable energy that is sold with its associated RECs as opposed to unbundled RECs that are sold separately from the underlying renewable energy generation.

Figure 1: Weighted Average RPS Procurement Expenditures of Investor-Owned Utilities' Bundled Renewable Energy from 2003-2023 (Real Dollars)



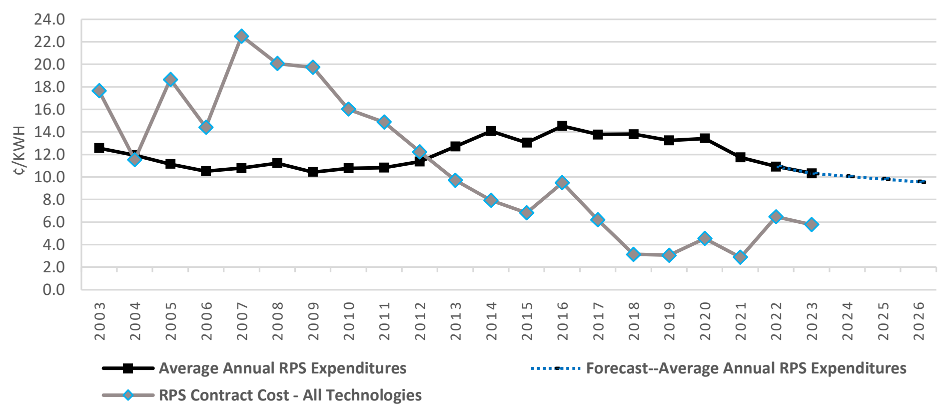
There was a lag between the large volume of contracts executed between 2007 and 2010 and the resulting increase in expenditure in the following years. This is because it takes several years from when a contract is executed to when the project is built, interconnected, and begins to deliver energy. Project development delays lengthen the time from when contracts are executed to when energy is actually delivered, and expenditures begin. Similarly, the forecast of average annual RPS expenditures decreases to reflect the fact that lower-cost resources contracted within the past several years are now starting to result in lower RPS expenditures as those projects begin delivering energy.

To approximate the impact of decreasing contract prices on future expenditures, Figures 1 and 2 include a forecasted decline in average annual RPS expenditures for IOUs at a rate of 2.5% per year between 2023 and 2026. The forecasted 2.5% drop in total RPS expenditures is significantly less than the historic 10.3% annual decrease in contract prices.[12] This forecast was selected because the impact of falling contract prices in future years is dampened by the cumulative RPS expenditures resulting from the state's increasing renewable goals, since over time each year's newly generating contracts represent a smaller and smaller portion of the IOUs' entire renewable portfolio. Figure 2 includes RPS contract costs executed in 2019 through 2023 for all retail sellers and IOUs' contract costs executed before 2019.

[12] See Figure 4 at 14.

Historic contract price trends for the RPS program can be seen in Figures 2 and 3, which show that executed contract prices peaked in 2007 and have been falling for RPS-eligible resources. See Appendix C for 2023 contract price data.

Figure 2: RPS Program Expenditures and Fixed Contract Costs from 2003-2023[13] (Real Dollars)



California Public Utilities Commission Report on RPS Costs and Cost Savings, May 2024

Total RPS Expenditures for IOUs

The IOUs' total combined direct RPS procurement expenditures decreased in real-dollar value from $5.2 billion in 2022 to $5.0 billion in 2023.[14] The IOUs' renewable procurement in 2023 also decreased slightly compared to 2022 procurement, from 49,665 GWh to 48,662 GWh, or from 48.4 percent to 47.3 percent of their retail load.[15]

IOUs' RPS Sales Solicitations

In 2023, retail sellers procured RPS energy from the 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 IOUs' expenditures or costs for IOU customers. Table 1 below provides a summary of the IOUs' RPS sales in 2023.

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[13] 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.

[14] See Table 4 at 12.

[15] The IOUs' 2023 RPS percentage may differ from the forecast reported in the 2023 RPS Annual Report which does not account for RPS sales in 2023 and reduces the IOUs' overall RPS percentage. The IOUs' RPS percentage for 2023 will be verified and reported in the 2024 RPS Annual Report to the Legislature in November 2024 following the IOUs' compliance filings for the 2023 calendar year.

Table 1: IOUs' 2023 RPS Sales Summary

IOU	RPS Sales (GWh)	RPS Sales Revenue (millions $)
PG&E	5,991	188.4
SCE	2,911	88.8
SDG&E	4,335	122.2
Total	13,237	399.4

Small and Multi-Jurisdictional Investor-Owned Utility Procurement Expenditures for 2023

In 2023, Liberty Utilities (Liberty), PacifiCorp, and Bear Valley Electric Service (BVES) spent approximately $18.3 million on RPS procurement as shown in Table 2. The SMJUs' RPS resources include biomass, geothermal, hydroelectric, solar photovoltaic, and wind.

Weighted SMJU Average Expenditures

In 2023, the weighted average RPS procurement expenditure for all Liberty contracts was 3.8 ¢/kWh, 4.1 ¢/kWh for PacifiCorp, and 1.0 ¢/kWh for BVES.[16]

Total SMJU Expenditures

For 2023, Liberty, PacifiCorp, and BVES had a total combined RPS procurement expenditure of $18.3 million compared to $16.9 million in 2022 in real-dollar value. The SMJUs' total renewable procurement increased by approximately 18 GWh from 2022 to 2023 which was the primary driver for increased expenditures.

[16] BVES's 2023 procurement expenditure data includes strictly REC-only contracts; therefore, it is not comparable to the other utilities' 2023 expenditures as they procured significant quantities of contracts that include the cost of acquiring RECs, capacity, and energy.

Table 2: Small and Multi-Jurisdictional Investor-Owned Utilities' Total RPS Expenditures in 2023[17]

	Liberty	PacifiCorp	Bear Valley Electric Service
Total (millions)	$10.77	$6.57	$0.98

Community Choice Aggregator and Electric Service Provider Procurement Expenditures for 2023

In 2023, there were 25 Community Choice Aggregators (CCAs) and 11 Electric Service Providers (ESPs) that served load and procured RPS-eligible energy. The CCAs' and ESPs' RPS portfolios include bioenergy, geothermal, small hydroelectric, solar photovoltaic, wind, and unbundled RECs. Tables 3 and 4 provide a summary of RPS procurement in 2022 and 2023 for CCAs and ESPs. The CCAs' total RPS fixed price contract expenditures decreased in 2023 primarily due to the decreasing amount procured.[18] Meanwhile, ESPs' total fixed price expenditures and procurement in 2023 increased in comparison to 2022.[19]

It is important to note that the CCA and ESP RPS expenditures reported in Tables 3 and 4 cannot be directly compared to the IOUs' RPS procurement expenditures because a portion of delivered energy in 2023 for CCAs and a large majority for ESPs originated from "Index plus REC" contracts. ESP and CCA Index plus REC contracting trends are shown below in Figure 3.[20] The reported contract price for Index plus 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 energy is delivered to the electricity grid pursuant to the contract.[21]

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[17] Ibid.

[18] For information regarding CCAs' forecasted RPS compliance, see CCAs' average actual and forecasted RPS percentages in the 2023 RPS Annual Report to the Legislature at 17.

[19] For information regarding ESPs forecasted RPS compliance, see ESPs' average actual and forecasted RPS percentages in the 2023 RPS Annual Report to the Legislature at 20.

[20] Index plus 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.

[21] In the CAISO's most recently released Annual Report on Market Issues and Performance, the average day-ahead energy price in 2022 was $90/MWh. (See CAISO's 2022 Annual Report on Market Issues and Performance, p. 4, (https://www.caiso.com/documents/2022-annual-report-on-market-issues-and-performance-jul-11-2023.pdf)). The price varies from the average depending on grid conditions and market supply and demand. For example, the average day-ahead price in 2021 was $53/MWh.

Index plus REC contracts differ significantly from "all-in" price RPS contracts for energy, RECs, and capacity, which make up the entirety of the IOUs' RPS portfolios, for which the price is otherwise "fixed" or set over the term of the contract. This difference in pricing constructs not only prevents comparison between the contract types, but basing a contract value on an index also introduces price volatility into the RPS program which the program was originally designed to address. In addition, it is important to consider contract vintages, as the IOUs executed a majority of their RPS procurement contracts in earlier years when technology prices were generally higher than that of more recent CCA and ESP contracts. The weighted average expenditures and total expenditures for CCAs and ESPs detailed in Table 3 and Table 4 below do not incorporate the costs for the Index plus REC contracts – expenditures show only Fixed Price contracts costs.

Table 3: Comparison of Community Choice Aggregator RPS Procurement and Procurement Expenditures between 2022 and 2023

	2022	2023
Weighted Average Fixed Contract Expenditures (¢/kWh)	4.3	4.1
Total Fixed Contract Expenditures (millions) [22]	$537	$474
Total Renewable Energy Delivered from Fixed Contracts (GWh)[23]	12,357	11,639
Average RPS Procurement (Fixed and Indexed Contracts) Percentage[24]	52%	59%

CCAs' total annual RPS procurement expenditures for all contracts, both fixed price and Index plus REC, decreased from $810 million in 2022 to $806 million in 2023, whereas renewables generation decreased from 31,775 GWh in 2022 to 30,380 GWh in 2023.

Table 4: Comparison of Electric Service Provider RPS Procurement and Procurement Expenditures between 2022 and 2023

	2022	2023
Weighted Average Expenditures (¢/kWh)	0.80	0.86
Total Fixed Contract Expenditures (millions) [25]	$6.7	$7.0
Total Renewable Energy Delivered from Fixed Contracts (GWh)[26]	844	778
Average RPS Procurement (Fixed and Indexed Contracts) Percentage[27]	47%	60%

[22] Total expenditures are derived from CCA responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 1, 2023.

[23] Total renewable energy delivered is derived from CCA responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 1, 2023.

[24] See Table 4 in the 2023 RPS Annual Report to the Legislature (p. 17).

[25] Total expenditures are derived from ESP responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 15, 2023.

[26] Total renewable energy delivered is derived from ESP responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 15, 2023.

[27] See Table 6 in the 2023 RPS Annual Report to the Legislature.

ESPs' total annual RPS procurement expenditures for all contracts, both Fixed price and Index plus REC, increased from $92 million in 2022 to $279 million in 2023 while renewables generation also increased from 7,191 GWh in 2022 to 8,414 GWh in 2023.

Figure 3: Comparison of Index plus REC Contracts in the CCAs' and ESPs' RPS Portfolios

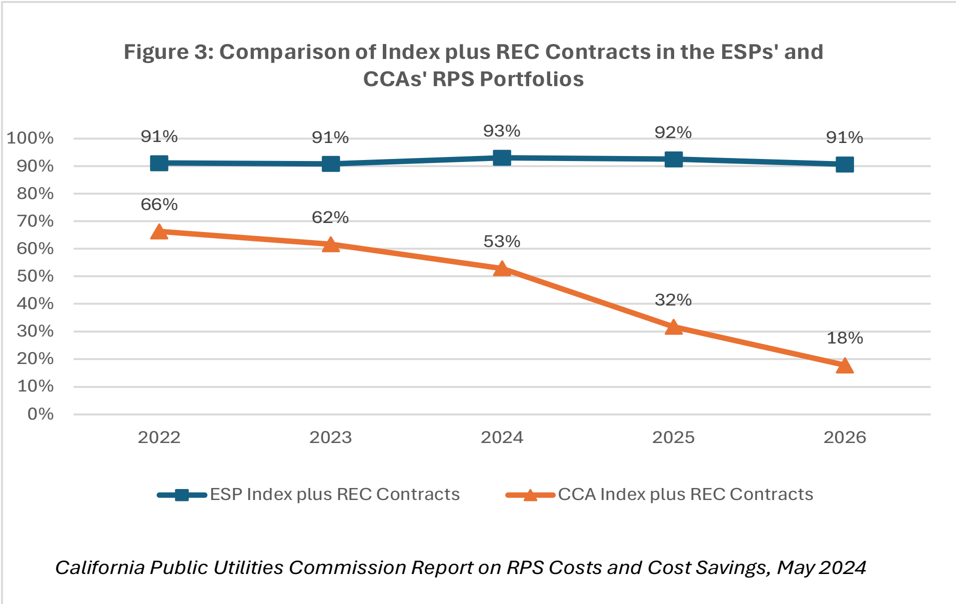


Figure 3 shows the percentage of CCA and ESP RPS contracts with Index plus REC price terms. The remaining contracts in their RPS portfolios have a fixed price term, i.e. all-in RPS contract.

CCAs as a group have been acting to reduce their reliance on Index plus REC contracts in recent years, increasing the proportion of fixed price contracts in the long-term outlook. The CCAs' shift to more fixed price contracts is in part due to the prevalence 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 now being in effect. 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 portfolio.

On the other hand, ESPs as a group have maintained their use of Index plus REC contracts. As a result of the ESPs' preference for Index plus REC contracts, their RPS portfolios generally do not provide much of a hedge against price volatility in the energy markets. Index plus REC contracts currently make up a little over two-thirds of all ESP contracts. It is worth noting that not all CCAs and ESPs follow the trends of their peer groups, i.e. some ESPs are strategically hedging their exposure to energy markets with fixed price RPS contracts and some CCAs are not hedging.

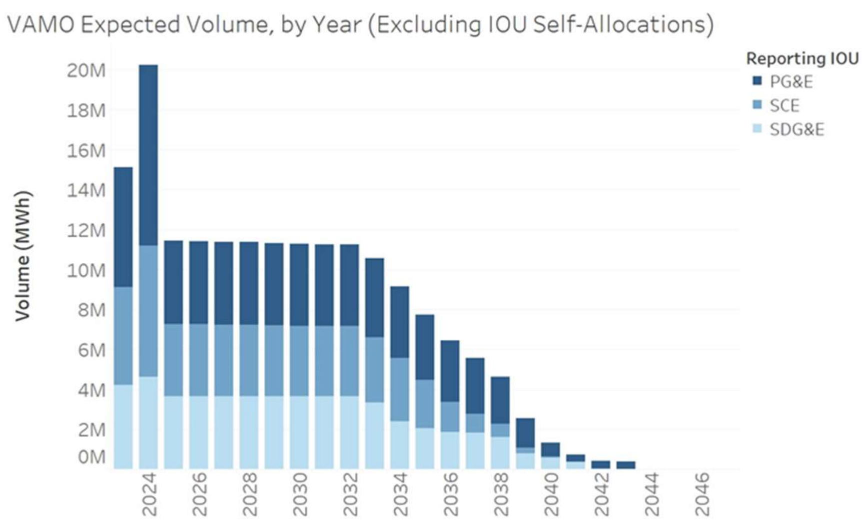
B. Voluntary Allocation and Market Offer

Through D.21-05-030, the CPUC adopted the Voluntary Allocation and Market Offer (VAMO) framework to optimize the IOUs' Power Charge Indifference Adjustment (PCIA)-eligible RPS portfolios, which had accumulated excess and/or uneconomic resources, primarily due to IOU load shifting to CCA service. The VAMO process was implemented in the RPS proceeding.

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.[28] In 2023, the IOUs completed Market Offer solicitations for the resources remaining after the Voluntary Allocations.[29] Appendix F lists retail sellers that accepted Voluntary Allocations and counterparties to IOUs' Market Offer contracts.[30]

Voluntary Allocations are valued at each year's respective Market Price Benchmark and Market Offer contracts are negotiated prices. IOU revenues are credited to respective Portfolio Allocation Balancing Accounts. While this year's report does not provide separate cost data on the VAMO process, this issue impacts retail sellers' RPS portfolio overall costs and expenditures. For example, the lower levels of RPS procurement carried out by CCAs and ESPs in 2023 may reflect VAMO's redistribution of the IOUs' PCIA-eligible resources from the IOUs portfolios to the CCAs and ESPs. Figure 4 below shows the amount IOUs have or will be allocated and selling to the CCAs and ESPs excluding allocations to the IOUs themselves.

Figure 4: Voluntary Allocations and Market Offers (VAMO) Volumes



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

29 D.22-11-021.

30 D.22-11-021 at Attachment A.

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

Investor-Owned Utilities

Table 5 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 5 shows the IOUs' RPS generation percentages for 2023.

Table 5 also shows that in 2023, RPS procurement expenditures on average were less than 15% of the IOUs' total revenue requirements. Compared to the total generation revenue requirements, the RPS expenditures make up a significantly smaller portion of the total revenue requirements, since total revenue requirements contain many large line items such as transmission expenditures, reliability costs, wildfire safety and mitigation programs, administrative costs, and capital expenses.

Table 5: Comparison of Investor-Owned Utilities' RPS Procurement to Revenue Requirements in 2023[31,32]

IOU	RPS 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	30.2%	$2.20	$4.90	44.9%	$17.76	12.4%
SCE	65.8%	$2.18	$6.73	32.4%	$17.52	12.4%
SDG&E	66.7%	$0.64	$1.09	58.7%	$4.38	14.6%

As retail sellers – including the 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, particularly as RPS expenditures are largely in line with non-RPS expenditures on a ¢/kWh basis. 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, which is explored in the next section.

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31 Revenue requirement numbers have been taken from the CPUC's "2023 California Electric and Gas Utility Cost Report" pursuant to Public Utilities Code § 913, April 2024.

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

In 2023, the IOUs' average cost of renewable energy was 10.0 ¢/kWh and the average cost of non-RPS energy was 8.3 ¢/kWh.[33] Using this metric, IOUs' renewable energy procurement likely added a premium of 1.7 ¢/kWh on average for the renewable energy procured to meet their RPS requirements.[34] However, as explained in Section 4 (below), this is an imperfect comparison, because it does not reflect likely savings from non-renewable energy demand reductions lessening the IOUs' reliance on higher-cost providers and thus decreasing unit cost.

Small and Multi-Jurisdictional Investor-Owned Utilities, Community Choice Aggregators and Electric Service Providers

Because the 2023 revenue requirement information for Liberty, BVES, and PacifiCorp is currently confidential pursuant to CPUC confidentiality rules,[35] the CPUC is not able to publicly analyze SMJU costs compared to their revenue requirements for 2022. For the CCAs and ESPs, the CPUC does not regulate their rates and thus does not have their revenue requirement information.

[33] See Table 7 at 30.

[34] The average RPS cost savings compared to non-RPS energy on a kilowatt-hour basis is represented by the following equation: *10.0 ¢/kWh (RPS Energy) – 8.3 ¢/kWh (Non-RPS Energy) = 1.7 ¢/kWh.*

[35] See D.06-06-066 for confidentiality rules related to revenue requirements.

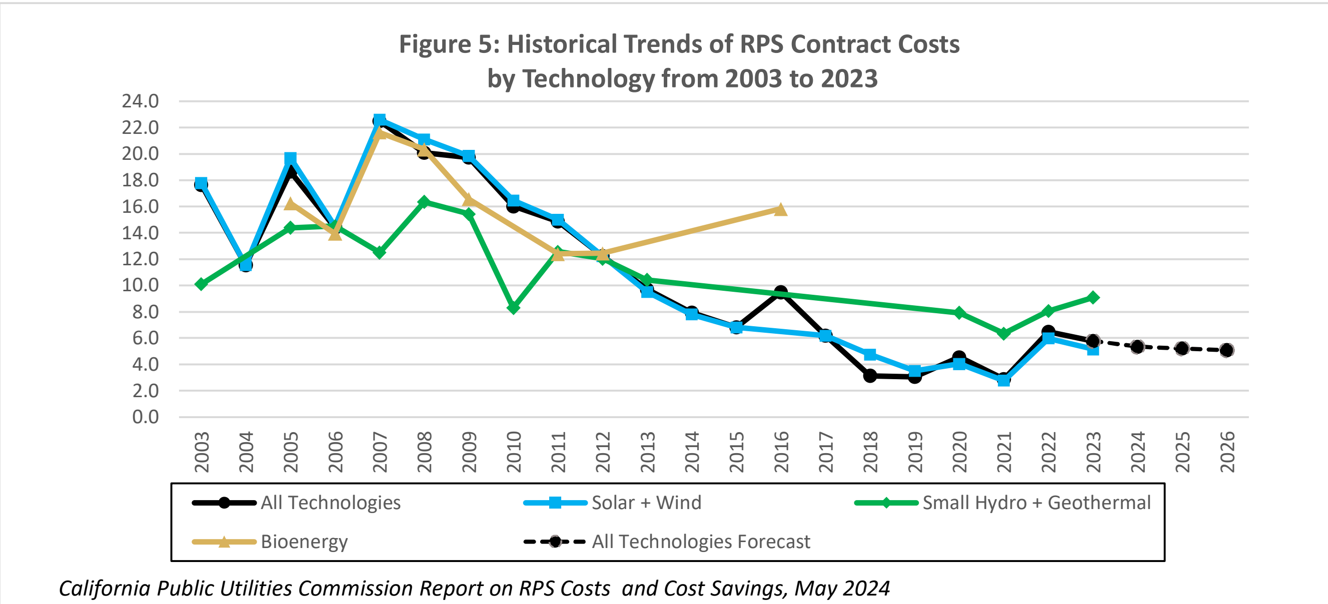
D. RPS Aggregated Contract Prices

CPUC staff examined the IOUs', CCAs', and ESPs' 2019 - 2023 executed contract prices.[36] Moreover, CPUC staff also reviewed IOUs' RPS contracts executed between 2003 and 2018 to provide historic contract cost trends.[37] To remove non-representational trends, contracts with a nameplate capacity of 3 MW or less were not included in Figure 5.[38]

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 1.3% annually between 2007 and 2023. Almost all 2023 procurement contracts with new facilities were executed by CCAs.

Figure 5: Historical Trends of RPS Contract Costs by Technology from 2003 to 2023



[36] 2019 through 2022 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 2003-2019 was self-reported by the IOUs through the CPUC's RPS Executed Projects Database.

[37] *See id.*

[38] Projects with a capacity of 3 MW or less made up a little over 1% of all of 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. 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.

The average price of IOU, CCA, and ESP contracts executed in 2023 that were greater than 3 MW was 5.8 ¢/kWh compared to 6.2 ¢/kWh in real-dollar value in 2022.

RPS Contract Prices for Resources 3 MW and Less

As noted above, RPS resources with a nameplate capacity of 3 MW or less are not included in Figure 5. Accordingly, the IOU's contracts signed in 2023 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 offered contract price for each product type is calculated using recent wholesale RPS contracts and is updated annually by CPUC resolution. No ReMAT contracts were executed in 2023, though the program was reopened in 2020,[39] and program rules were modified in 2021.[40]

IOU Bioenergy Market Adjusting Tariff (BioMAT) Contracts

BioMAT is a bioenergy Feed-in-Tariff program that uses a standard contract and a market-based mechanism to arrive at the offered program contract price. BioMAT intends to promote a competitive market via a simple procurement mechanism for bioenergy market entrants. BioMAT allocates procurement to the discrete bioenergy categories of Biogas, Dairy/Agriculture, and Sustainable Forest Management. Table 6 shows the average BioMAT contract price and total capacity procured in 2023 by the three IOUs.

Table 6: Investor-Owned Utilities' 2023 BioMAT Procurement Summary

BioMAT Category	Contracted Capacity (MW)	Average Contract Price (¢/kWh)
Biogas	7	12.4
Dairy/Agriculture	10	18.8
Sustainable Forest Management	6	17.2
Total	24	17.0

[39] D.20-10-005; https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M348/K746/348746212.PDF.

[40] D.21-12-032; https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M433/K005/433005845.PDF.

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

The CCAs are not required to offer BioMAT contracts and are not eligible to offer ReMAT contracts. During 2023, the CCAs did not execute any new-build RPS-eligible facilities with 3 MW or less of capacity.[41] In November 2023, CCAs were authorized to join the BioMAT program, though, and may have BioMAT contracts and costs in the future.

Bioenergy Renewable Auction Mechanism (BioRAM) Contracts

Pursuant to the Governor's Emergency Order Addressing Tree Mortality, Senate Bill (SB) 859 and SB 901, the BioRAM program required the IOUs to procure 146 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.[42]

In 2023, there was no change year over year with six biomass facilities for a combined total capacity of 154 MW at an average contract price of 12.2 ¢/kWh.

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[41] This data was obtained through the joint RPS-PCIA Semi-Annual Data Report, submitted February 15, 2023.

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

4. Renewables Program Cost Premiums and/or Savings

This section addresses the cost premiums and/or savings associated with the IOUs', SMJUs', CCAs', and ESPs' procurement of renewable resources in 2023, consistent with the requirements of § 913.3(c).

Section 913.3(c)

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

For the purposes of this report, the IOUs and SMJUs 2023 RPS procurement costs are compared to non-RPS procurement costs to determine cost savings. This comparison likely exaggerates 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. 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. CPUC staff also 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. Further, 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. Additionally, CCAs and ESPs primarily have contracts that do not provide fixed price contracts for energy and capacity and are tied to index prices. This limits and in some instances prevent cost comparisons in this report. This procurement approach may also introduce price volatility in California's RPS Standard program which the program was designed in part to address.

Consequently, there is no perfect counterfactual to assess RPS program premiums or savings, because in the absence of RPS procurement, non-RPS resources would still be procured, and the additional demand for non-RPS resources would likely result in higher costs than the cost of non-RPS resources in the lower demand market for them that would result where demand is present from the RPS program. This challenge is also reflected in the previous section's assessment of RPS expenditures as part of the IOUs' 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.

A. Investor-Owned Utilities' Cost Premiums / Savings

In 2023, the IOUs' annual RPS procurement expenditures represented a weighted average 1.7 ¢/kWh cost premium versus their average non-RPS procurement expenditures.[43] Individually, as per Table 7, PG&E and SCE both paid more for RPS procurement by 3.4 ¢/kWh and 5.0 ¢/kWh, respectively. Notably, SDG&E paid a discount for RPS energy—compared to non-RPS energy—of 9.0 ¢/kWh.[44] This pattern is notable, where non-RPS price expenditures are lower than RPS price expenditures for PG&E and SCE while higher for SDG&E. Expenditures for both categories mostly declined year over year for all of the IOUs but price levels for non-RPS contracts fell slightly more in 2023 for PG&E and SCE while rising slightly for SDG&E. PG&E and SCE appear to be realizing some declines in RPS prices from the expiration of higher priced contracts signed in the past.[45] It is also possible that the 2022 non-RPS expenditures had been influenced by factors such as the fuel cost volatility which raised prices for non-RPS costs during that period. Meanwhile, 2023 RPS expenditures were relatively consistent with 2022 expenditures.

Table 7: Investor-Owned Utilities' 2023 Average RPS and Non-RPS Eligible Procurement Expenditure[46] (¢/kWh)

Method	PG&E	SCE	SDG&E	Weighted Average
2023 Non-RPS	9.0	3.7	17.9	8.3
2023 RPS	12.4	8.7	8.9	10.0

[43] *Supra*, note 32 at 15.

[44] This savings appears inconsistent with Table 7 due to the RPS and Non-RPS values rounding in different directions.

45 For example, Q3 2023 day-ahead market prices averaged $60/MWh which is almost half of Q3 2022 (CAISO Q3 2023 Report on Market Issues and Performance, February 21, 2024).

[46] Derived from responses to Energy Division's RPS-PCIA Semi-Annual Data Report, submitted February 15, 2023, and CPUC's 2023 AB 67 report, to be published April 2024

Based on total volumes of RPS and non-RPS eligible procurement expenditures, the 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: Investor-Owned Utilities' 2023 RPS Cost Savings: Non-RPS Eligible Comparison

Cost Savings Compared to 2023 Average Non-RPS Expenditure (millions)	
PG&E	($744.0)
SCE	($1,244.5)
SDG&E	$660.2
Cost savings are displayed as positive figures while cost premiums are displayed as (negative) figures.	

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

In 2023, the RPS procurement expenditure for SMJUs represented a 3.2 ¢/kWh cost savings compared to their average non-RPS-eligible expenditure. The cost savings for RPS energy compared to non-RPS energy for Liberty and PacifiCorp was 3.4 ¢/kWh and 1.9 ¢/kWh, respectively. BVES' RPS procurement consisted solely of REC-only products; thus, BVES' RPS expenditures are not directly comparable to their non-RPS expenditures, which include additional costs for obtaining energy and capacity benefits.

Table 9: Small and Multi-Jurisdictional Investor-Owned Utilities' 2023 Average Non-RPS Eligible Procurement Expenditure (¢/kWh)

Method	Liberty	PacifiCorp	Bear Valley Electric Service	Weighted Average
2023 Non-RPS	8.3	6.0	7.5	6.9
2023 RPS	4.9	4.1	0.9	3.7

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' 2023 RPS Cost Savings: Non-RPS Eligible Comparison[47]

	Cost Savings Compared to 2023 Average Non-RPS Expenditure (millions)
Liberty	$10.75
PacifiCorp	$6.56
Bear Valley Electric Service	N/A
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.	

[47] Cost savings or premiums are calculated by multiplying each SMJU's average 2023 non-RPS eligible expenditure (Table 9) by its total volume of RPS procurement in 2023 then subtracting that value from the SMJUs' 2023 RPS procurement expenditure (Table 2).

B. Community Choice Aggregators' Cost Premiums / Savings

In 2023, the RPS procurement expenditure for CCAs represented a 2.0 ¢/kWh cost savings compared to their average non-RPS-eligible expenditure.[48] As mentioned previously, the weighted average RPS expenditures for CCAs excludes the Index plus REC contracts and cannot be directly comparable to the IOUs' and SMJUs' RPS expenditures.

Table 8: Community Choice Aggregators' 2023 Average Non-RPS Eligible Procurement Expenditure (¢/kWh)

Method	Weighted Average
2023 non-RPS	6.1
2023 RPS	4.4

Based on total volumes of RPS generation procured and non-RPS eligible procurement expenditures, the CCAs are estimated to have realized the following cost savings versus an equivalent amount of non-RPS procurement:

Table 9: Community Choice Aggregators' 2023 RPS Cost Savings Compared to Non-RPS Energy [49]

	Cost Savings Compared to 2023 Average Non-RPS Expenditure (million)
Community Choice Aggregators	$236.3
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.	

C. Electric Service Providers' Cost Premiums / Savings

In 2023, the RPS procurement expenditure for ESPs represented a 6.4 ¢/kWh cost savings compared to their average non-RPS-eligible expenditure. As mentioned previously, the weighted average RPS expenditures for ESPs do not incorporate the Index plus REC contracts and cannot be directly comparable to the IOUs', SMJUs' RPS expenditures.

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[48] This savings appears inconsistent with Table 11 due to the RPS and Non-RPS values rounding in different directions.

[49] Cost savings or premiums are calculated by multiplying CCAs' average 2023 non-RPS eligible expenditure (Table 11) by volume of RPS procurement in 2023 (excluding Index + REC deliveries) then subtracting that value from the CCAs' 2023 RPS procurement expenditure (Table 3).

Table 10: Electric Service Providers' 2023 Average Non-RPS Eligible Procurement Expenditure (¢/kWh)[50]

Method	Weighted Average
2023 Non-RPS	7.2
2023 RPS	0.8

Based on total volumes of RPS generation procured and non-RPS eligible procurement expenditures, the ESPs are estimated to have realized the following cost savings versus an equivalent amount of non-RPS procurement:

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

	Cost Savings Compared to 2023 Average Non-RPS Expenditure (millions)
Electric Service Providers	$49.89
Cost savings are displayed as positive figures while cost premiums are displayed as negative figures.	

[50] Weighted average RPS expenditures for ESPs do not incorporate the Index plus REC contracts costs. See footnote 21 for the most recent Index energy price reported by CAISO.

5. Appendices

Appendix A: California Public Utilities Commission RPS Activities and Milestones

January 2023	▪ IOUs, CCAs, and ESPs submitted Final 2022 RPS Procurement Plans ▪ CPUC staff approved the IOUs' short-term Market Offer solicitation protocols.
February 2023	▪ CPUC approved the IOUs' long-term pro-forma Market Offer contracts and solicitation protocols.
March 2023	▪ IOUs, CCAs, and ESPs filed Final 2017-2020 RPS Compliance Reports ▪ CPUC adopted D.22-03-009 closing Rulemaking 15-02-020.
April 2023	▪ CPUC approved the IOUs' proposed short-term Market Offer contracts ▪ CPUC issued assigned Commissioner Scoping Memo and Ruling for R.22- 10-010 ▪ CPUC staff held a workshop on AB 843 implementation
May 2023	▪ CPUC issued the 2023 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 2023 RPS Procurement Plans ▪ CPUC adopted Resolution E-5264 approving PG&E rider and amendment to BioMAT PPA with Scotts Valley Energy Corporation ▪ CPUC issued Administrative Law Judge's Ruling requesting party comments on AB 843 workshop questions
June 2023	▪ CPUC adopted Resolution E-5270 adopting 2023 updated administratively set fixed avoided-cost rates for the ReMAT program. ▪ CPUC adopted Resolution E-5275 approving Bear Valley Electric Service, Inc. long-term power purchase agreement with Shell Energy North America.
July 2023	▪ IOUs, CCAs, and ESPs submitted Draft 2023 RPS Procurement Plans ▪ RPS Compliance Report Webinar ▪ CPUC adopted Resolution E-5275 approving a Power Purchase Agreement between Bear Valley Electric Service and Shell Energy North America for Procurement of Bundled RPS Energy
August 2023	▪ IOUs, CCAs, and ESPs submitted annual RPS Compliance Reports ▪ CPUC adopted D.23-08-003 granting Petition for Modification of D.19-09-043 regarding Effective Load Carrying Capability ▪ CPUC adopted D.23-08-032 approving Liberty Utilities Application 21-04- 006

September 2023	▪ CPUC approved Order Extending Statutory Deadline of R.18-07-003 to July 31, 2024
October 2023	▪ CPUC adopted Resolution E-5288 implementing SB 1109 (Caballero, 2022) extending BioRAM program.
November 2023	▪ CPUC issued the 2023 Annual RPS Report to the Legislature. ▪ CPUC adopted Resolution E-5291 approving Market Offer Long-Term Solicitation Agreement between Southern California Edison Company and Clean Power San Francisco. ▪ CPUC adopted D.23-11-084 implementing AB 843 (Aguiar, 2021)
December 2023	▪ CPUC adopted D.23-12-008 on the 2023 RPS Procurement Plans. ▪ Energy Division issued SB 155 letters to retail sellers at risk of not meeting RPS requirements.
January 2024	▪ CPUC approved BioMAT Tariff Modifications in compliance with AB 843. ▪ CPUC adopted new RPS Order Instituting Rulemaking 24-01-017. ▪ CPUC adopted Resolution E-5297 approving Power Purchase Agreement between Pacific Gas and Electric Company and Northern Orchard Solar PV, LLC.

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

Overview of Tables

Table B-1 and B-2 show, for each IOU, the weighted average time-of-delivery (TOD) adjusted RPS procurement expenditures for 2023.[51] Tables B-3 and B-4 show the weighted average RPS procurement expenditures for 2023 for CCAs and ESPs. Per the confidentiality requirements in Public Utilities Code § 913.3, some of the data within this report is redacted in order to protect market sensitive information.

For the IOUs, RPS procurement expenditures are driven by a large volume of contracts signed between 2007 and 2010 at higher prices compared to prices observed in the current market.[52] Recent RPS contracts executed at lower prices are not fully reflected in the weighted average RPS procurement expenditures below as there is a lag between when the lower cost contracts are executed and when RPS procurement expenditures will decline.

In addition:

- The "Average RPS Procurement Expenditures" represent the total weighted average payments made to renewable generators for 2023.
- Procurement expenditures represent weighted averages by capacity procured on a per kilowatt-hour basis. All figures are in 2023 dollars.

[51] Table B-1 provides all procurement expenditure information for every IOU RPS-eligible contract, including utility-owned generation (UOG) projects. The tables break down the actual price for production in 2023 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.

[52] See historical trend of RPS contract costs in Figure 4 at 16.

Table B-1. Weighted Average RPS Procurement Expenditures for IOUs in 2023 (¢/kWh)

	PG&E	SCE	SDG&E	Total
Biogas				
0-3 MW	9.9	12.5	10.6	11.7
+3-20 MW	Only 2 Contracts	5.5	Only 2 Contracts	11.6
Biogas Total	**12.0**	**9.8**	**6.0**	**11.7**
Biomass				
0-3 MW	Only 2 Contracts			-
+3-20 MW		Only 1 Contract		-
+20-50 MW	12.7	11.3	Only 1 Contract	12.5
+50-200 MW	Only 1 Contract			-
Biomass Total	**11.9**	**11.5**	**Only 1 Contract**	**13**
Geothermal				
+3-20 MW	Only 2 Contracts	Only 2 Contracts		8.4
+20-50 MW		7.8		7.4
+50-200 MW		9.9		9.8
+200 MW		Only 1 Contract		-
Geothermal Total	**Only 2 Contracts**	**7.7**	**-**	**8.2**
Small Hydro				
0-3 MW	12.6	8.9	9.4	10.9
+3-20 MW	Only 2 Contracts			-
+20-50 MW	11.9			7.9
Small Hydro Total	**12.1**	**8.9**	**9.4**	**10.2**
Solar Photovoltaic				
0-3 MW	11.9	12.5	11.8	12.2
+3-20 MW	9.9	8.9	8.1	9.0
+20-50 MW	13.2	Only 1 Contract	Only 2 Contracts	13.4
+50-200 MW	11.9	5.9	11.6	8.6
+200 MW	16.6	11.6		13.6
Solar Photovoltaic Total	**13.7**	**8.9**	**11.4**	**10.9**
Solar Thermal				
+50-200 MW	16.7	16.1		17.2
+200 MW	20.8			20.8
Solar Thermal Total	**19.8**	**16.1**	**-**	**18.6**
Wind				
0-3 MW		8.3		8.4
+3-20 MW	6.6	5.7	7.4	6.6
+20-50 MW	Only 1 Contract	9.5	Only 1 Contract	8.9
+50-200 MW	7.9	9.3	5.7	8.2
+200 MW		7.9	Only 1 Contract	8.4
Wind Total	**12.4**	**8.9**	**6.4**	**8.1**
UOG Small Hydro				
0-3 MW	90.8	5.7		32.2
+3-20 MW	25.7	5.3		18.5
+20-50 MW	6.6	2.8		4.2
UOG Small Hydro Total	**24.2**	**4.4**	**-**	**15.3**
UOG Solar Photovoltaic				
0-3 MW	34.8		46.4	36.3
+3-20 MW	21.5		101.1	22.2
UOG Solar Photovoltaic Total	**21.7**		**88.4**	**22.5**
Weighted Average of All Resources	**13.0**	**8.6**	**9.6**	**10.8**
Weighted Average of All Resources (Excluding UOG)	**12.4**	**8.6**	**9.6**	**10.6**

Table B-2. Weighted Average RPS Procurement Expenditures for CCAs (Bundled Energy, Index plus REC, and REC-Only Transactions) for 2023 (¢/kWh)

	Total[53]	Index +REC Total
Biogas		
0-3 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)	-	0.3
Biogas Total	**Only 1 Contract**	**0.3**
Biomass		
0-3 MW	Only 1 Contract	
3-20 MW	Only 1 Contract	
20-50 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)	-	1.0
Biomass Total	**7.4**	**1.0**
Geothermal		
0-3 MW	Only 2 Contracts	
3-20 MW	6.7	
20-50 MW	6.4	
50-200 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)	-	Only 1 Contract
Geothermal Total	**6.3**	**Only 1 Contract**
Small Hydro		
0-3 MW	Only 1 Contract	
3-20 MW	4.7	
20-50 MW	Only 2 Contracts	
Index + REC (excludes cost of energy index)	-	Only 1 Contract
Small Hydro Total	**5.1**	**Only 1 Contract**
Solar Photovoltaic		
0-3 MW	9.3	
3-20 MW	8.8	
20-50MW	4.0	
50-200 MW	3.0	
+200 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)	-	3.1
Solar Photovoltaic Total	**3.2**	**3.1**
Various/REC-Only[54]		
0-3 MW	2.3	
Index + REC (excludes cost of energy index)	-	2.3
Various/REC-Only Total	-	2.3
Wind		
0-3 MW	4.6	
3-20MW	4.8	
20-50 MW	5.3	
50-200 MW	4.7	

[53] Totals for each technology type exclude expenditures from Index + REC contracts.

[54] 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.

+200 MW	Only 2 Contracts	
Index + REC (excludes cost of energy index)		2.0
Wind Total	**4.4**	**2.0**
Weighted Average of All Resources	**4.4**	**2.2**[55]

Table B-3. Weighted Average RPS Procurement Expenditures for ESPs (Bundled Energy, Index plus REC, and REC-Only Transactions) for 2023 (¢/kWh)

	Total	Index + REC Total
Biogas		
0-3 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)		Only 1 Contract
Biogas Total	**Only 1 Contract**	**Only 1 Contract**
Biomass		
Index + REC (excludes cost of energy index)		Only 1 Contract
Biomass Total		**Only 1 Contract**
Geothermal		
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)		Only 2 Contracts
Small Hydro Total	**Only 2 Contracts**	**Only 2 Contracts**
Solar Photovoltaic		
0-3 MW		6.4
3-20 MW		Only 1 Contract
20-50 MW		Only 1 Contract
50-200 MW		1.1
+200 MW		Only 2 Contracts
Index +REC (excludes cost of energy index)		4.0
Solar Photovoltaic Total		**4.0**
Wind		
0-3 MW	Only 1 Contract	4.9
3-20 MW		Only 1 Contract
50-200 MW		Only 1 Contract
Index + REC (excludes cost of energy index)		3.5
Wind Total	**Only 1 Contract**	**1.1**
Various/REC Only		
0-3 MW	0.6	3.4
Index + REC (excludes cost of energy index)		
Various/REC-Only Total	**0.6**	**3.4**
Weighted Average of All Resources	**0.9**	**3.7**[56]

[55] Excludes Various/REC-only expenditures.

[56] 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 of the IOUs' RPS contracts approved by the CPUC in 2023. Tables C-2 and C3 show the weighted average contract prices for the CCA and ESP RPS contracts executed in 2023.

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 2023 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 2023 for IOUs (¢/kWh)

	PG&E	SCE	SDG&E	Total
Biomass				
0-3 MW	Only 1 Contract			-
Biomass Total				
Geothermal				
+50-200 MW		Only 1 Contract		-
Geothermal Total		**-**	**-**	**-**
Small Hydro				
0-3 MW	Only 1 Contract			-
Small Hydro Total				
Solar Photovoltaic				
0-3 MW	5.1	Only 1 Contract		3.6
+3-20 MW				
+20-50 MW				
+50-200 MW	Only 1 Contract	Only 2 Contracts	Only 2 Contracts	3.9
+200 MW		Only 1 Contract		-
Solar Photovoltaic Total	**4.2**	**4.1**	**-**	**-**
Average of All Resources	**9.2**	**4.9**	**5.3**	**-**

Table C-2. Average Contract Price of All Renewable Energy Contracts for 2023 for CCAs (¢/kWh) Including Index plus REC contracts

Executed in 2023 for CCAs (¢/kWh)	Total	REC
Biomass		
3-20 MW	Only 1 Contract	
20-50 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)		4.2
Biomass Total	**-**	**4.2**
Geothermal		
0-3 MW		
3-20 MW	12.8	
20-50 MW		
Index + REC (excludes cost of energy index)		
Geothermal Total	**12.8**	
Solar Photovoltaic		
0-3 MW	13.7	
3-20 MW	6.1	
20-50 MW		
50-200 MW	4.5	
+200 MW		
Index + REC (excludes cost of energy index)		6.2
Solar Photovoltaic Total	**9.2**	**6.2**
Various/REC-Only[57]		
Index + REC (excludes cost of energy index)		
REC-Only		
Wind		
3-20 MW		
20-50 MW		
50-200 MW	Only 2 Contracts	
+200 MW	Only 1 Contract	
Index + REC (excludes cost of energy index)		6.0
Wind Total	**-**	**6.0**
Average of All Resources	**8.6**	**5.1[58]**

[57] 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.

[58] Excludes Various/REC-Only contracts.

Table C-3. Average Contract Price of All Renewable Energy Contracts for 2023 for ESPs Including Index plus REC Contracts (¢/kWh)

Executed in 2023 for ESPs (¢/kWh)	Total	REC
Biogas		
Index + REC (excludes cost of energy index)		Only 1 Contract
Biogas Total		Only 1 Contract
Various/REC-Only[59]		
0-3 MW		
Index + REC (excludes cost of energy index)		2.1
REC-Only		**2.1**
Wind		
50-200 MW	**Only 1 Contract**	
Index + REC (excludes cost of energy index)		
Wind Total	**-**	**-**
Average of All Resources	**-**	**1.9**[60]

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

[59] 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.

[60] Excludes Various/REC-Only contracts.

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: California's Load Serving Entities Operating in 2023

Investor- Owned Utilities (IOUs)	Small and Multi-Jurisdictional Utilities (SMJUs)	Community Choice Aggregators (CCAs)	Electric Service Providers (ESPs)
• Pacific Gas and Electric Company • Southern California Edison • San Diego Gas & Electric	• Bear Valley Electric Service • Liberty Utilities (formerly CalPeco Electric) • PacifiCorp	• Apple Valley Choice Energy • Ava Community Energy (formerly East Bay Community Energy) • Central Coast Community Energy (formerly Monterey Bay Community Power) • City of Palmdale • City of Pomona • City of Santa Barbara • Clean Energy Alliance • Clean Power Alliance of Southern California • CleanPowerSF • Desert Community Energy • 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 • Rancho Mirage Energy Authority • Redwood Coast Energy Authority • San Diego Community Power • San Jacinto Power • San Jose Clean Energy • Silicon Valley Clean Energy • Sonoma Clean Power Authority • Valley Clean Energy Alliance	• 3 Phases Renewables • BP Energy Retail Company (formerly EDF Energy Services) • Calpine Energy Solutions • Calpine Power America • Commercial Energy of California • Constellation New Energy • Direct Energy Business • Pilot Power Group • Shell Energy North America • Tiger Natural Gas • UC Regents

Appendix F: Voluntary Allocations and Market Offer Contracts

Accepted Voluntary Allocations from IOUs[61]	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	

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