2024 CALIFORNIA RENEWABLES PORTFOLIO STANDARD

Annual Report

NOVEMBER 2024

California Public Utilities Commission

A digital copy of this report can be found at:

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Executive Summary

The California Public Utilities Commission (CPUC) reports to the Legislature each year on the progress of the Renewables Portfolio Standard (RPS) program (Senate Bill (SB) 1222[1] (Hertzberg, Chapter 842, Statues of 2016)). This report describes the progress of the State's electricity retail sellers[2] in meeting the RPS program requirements for 2023 and future years. This report also satisfies the CPUC's reporting requirements under SB 1174 (Hertzberg, Chapter 229, Statues of 2022) which require the CPUC to perform an assessment of reported annual data regarding the relationship between RPS eligible generation and storage resources, and transmission development.

The report also identifies specific challenges to the RPS program and recommendations for addressing those challenges. Specifically, the report addresses challenges related to bioenergy, generation and supply chain issues, and interconnection demand.

While the status of RPS compliance and enforcement is included, a subsequent annual report will address the 2021-2024 compliance period after the end of the compliance period.

Finally, it is important to note that while this report is focused on the RPS program, as directed by statute, the state's integrated resource planning (IRP) process will play an increasingly central role in future renewable project development. Through the IRP process, the CPUC requires new electricity resources to meet reliability and increasingly stringent greenhouse gas (GHG) targets to achieve the SB 100 (De León, Chapter 312, Statues of 2018) goal of 100 percent of retail electricity sales being met with renewable and zero-carbon resources by 2045.

California's Electricity Retail Sellers are Meeting Annual RPS Targets and On-track for Meeting the 2021-2024 Compliance Period Requirements

Although RPS compliance determinations are only made for the compliance period in its entirety, retail seller performance is also measured against annual targets, though these are non-binding.

- Most retail sellers report meeting or exceeding the 41.3 percent RPS annual procurement target for 2023.[3]
- All three of the Investor-Owned Utilities (IOUs) show procurement meeting the 2023 target, and all three also forecast meeting their 2021-2024 compliance period requirements.
- Two of the three small and multi-jurisdictional Utilities (SMJUs) show procurement meeting the 2023 target, but only one forecasts meeting their 2021-2024 compliance period RPS requirements at this time. Despite this, SMJU procurement in aggregate is still showing likely compliance for the 2021-2024 compliance period, as these shortfalls are only for small amounts.

1 As codified in Public Utilities Code § 913.4. See Appendix F for full text of § 913.4.
2 See Appendix E for full list of active retail sellers.
3 Based on preliminary 2023 Annual Compliance Report filings submitted to the CPUC in August 2024.

- 22 of the 26 Community Choice Aggregators (CCAs) show procurement meeting the 2023 target; however, only 19 reported forecasts that would have them meet or exceed requirements for the compliance period as a whole. Most shortfalls are relatively small, and the CCA procurement overall is substantial, as a significant number of CCAs intentionally procure renewable energy at a level above RPS mandates as part of their environmental goals.
- Of the 10 Electric Service Providers (ESPs) actively serving load in 2023, seven showed procurement meeting the 2023 target, and five forecast meeting their 2021-2024 compliance period requirements. However, ESPs in aggregate have a lower balance than the other types of retail sellers. Some ESPs have historically tended to procure towards the end of a compliance period, but they risk facing penalties if they are not already well along the procurement process.

2023 RPS Prices For New Contracts Decreased

- The average RPS eligible energy contract price dropped 1.3 percent per year from 2007 to 2023.
- The overall downward trend in contract prices can be largely attributed to falling prices for wind and solar technologies, as the overall contracted commitment to those sources by retail sellers in California has increased over time.

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

Large Quantities of Renewable Energy and Storage Resources Have Come Online in Recent Years, but Delayed In-Service Dates for Transmission Projects Can Cause Delays for RPS Eligible Resources

SB 1174 requires transmission owners to report on delayed in-service dates for transmission projects and on the generation and storage resources that depend on them. Since 2020, there have been over 20 GW of new clean energy and storage resources that have been interconnected to the California Independent System Operator (CAISO) grid. Many of the resources have been able to come online without significant network transmission projects being required. However, there are many resources, potentially as many as 9 GW of RPS generation that have been delayed or at risk of delay due to delayed transmission project timelines driven by land rights, customer actions, materials, and other issues.

SB 1174 also requires the CPUC to perform an assessment of reported annual data regarding the relationship between RPS eligible generation and storage resources, and transmission development.[4]

- Of the transmission projects related to RPS and storage projects reported by the IOUs, 119 transmission projects, or 71 percent, experienced delays or changes to their original in-service dates.

4 Following this initial in-depth assessment, staff will review the assessment methodology for data consistency and quality improvements in the future, as this is the first effort to provide detailed SB 1174 reporting.

- There are 172 renewable generation and storage resources, representing 28.4 GW, that depend on the 119 delayed transmission projects.
- Delayed transmission projects have the potential to impact 16 GW out of the 28.4 GW of renewable generation and storage resources reported by the IOUs, with 9 GW being RPS eligible resources that have been delayed or are at risk of delay. Despite these delays in transmission projects, CPUC staff estimate that over 20 GW of new clean generation and storage resources have come online in California since January 2020.[5]

CPUC staff are working with other state agencies and the CAISO to identify and address the most impactful causes of these delays and will continue to coordinate with transmission owners to better identify the main causes of long and impactful delays. Additionally, staff will consider how to cross reference the transmission projects listed in each IOU's SB1174 data templates against those listed in the latest Transmission Development Forum (TDF) data and Transmission Project Review (TPR) data. Lastly, the Tracking Energy Development (TED) Task Force is focused on coordinating action to address barriers that may impact energy development throughout the State.[6]

5 More detailed information on recent new clean generation that has come online can be found at: https://www.cpuc.ca.gov/trackingenergy.

6 More information on the Transmission Development Forum (TDF), Transmission Project Review (TPR), and Tracking Energy Development (TED) Task Force can be found at: https://www.cpuc.ca.gov/trackingenergy.

Background

Pursuant to Public Utilities Code 913.4, the California Public Utilities Commission (CPUC) reports to the Legislature each November on the progress of California's electricity retail sellers in meeting the requirements of the Renewables Portfolio Standard (RPS) program. This report complies with sub-sections (a) through (g), which require the following to be addressed:

a. Progress on RPS procurement activities.
b. Details on RPS activities and implementation.
c. Projected ability to meet RPS under cost limitations.
d. Status of RPS plans, activities, procurement, and transmission.
e. Barriers and policy recommendations to achieving the RPS.
f. Efforts of electrical corporations related to workforce development, training, and diversity.
g. A systemwide assessment of delays to interconnection or transmission approvals for eligible renewable energy resources or energy storage resources.

Legislative History

The California RPS program was established in 2002 by SB 1078 (Sher, Chapter 516, Statues 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, Chapter 464, Statues of 2006), which required that the 20 percent mandate be met by 2010. In April 2011, SB 2 (1X) (Simitian, Chapter 1, Statues of 2011) codified achievement of the 33 percent RPS requirement by 2020. In 2015, SB 350 (De León, Chapter 547, Statues of 2015) changed the mandate to 50 percent RPS by December 31, 2030 and included interim annual RPS targets with three-year compliance periods. In addition, SB 350 requires that 65 percent of RPS procurement must be derived from long-term contracts of 10 or more years. In 2018, SB 100 (De León, Chapter 312, Statues of 2018) accelerated and increased the RPS to 60 percent by 2030 and established a goal of 100 percent of retail electricity sales being met with renewable and zero carbon resources by 2045.

California's RPS Program

California's ambitious RPS program is jointly implemented by the CPUC and the California Energy Commission (CEC) and requires the State's load serving entities (LSEs)[7] to procure 60 percent of their total electricity retail sales from renewable energy resources by 2030. Increasing the renewables in the State's energy mix provides a range of benefits to Californians, such as reducing GHG emissions and air pollution, stabilizing electricity rates, providing a physical hedge against methane gas price volatility and contributing to the reliable operation of the electrical grid.

All California electricity retail sellers, or entities engaged in the sale of electricity to end-use customers, are required to comply with the requirements of the RPS program.[8] Entities under the CPUC's jurisdiction serve approximately 74 percent of the total electricity demand in California. The Publicly Owned Utilities (POUs) serve the remaining 26 percent.[9] Of these retail sellers within the CPUC's jurisdiction, the IOUs served approximately 50 percent of the total electricity load in 2023, while small and multi-jurisdictional utilities (SMJUs) served 1 percent, community choice aggregators (CCAs) served 37 percent, and electric service providers (ESPs) served the remaining 12 percent.

7 LSEs include retail sellers, which are investor-owned utilities (IOUs), small and multi-jurisdictional utilities (SMJUs), community choice aggregators (CCAs), and electric service providers (ESPs), as well as publicly owned utilities (POUs). See Appendix E for a complete list of active retail sellers that the CPUC regulates.

8 *See* the Compliance & Enforcement section for more details on RPS program requirements.

9 POUs report their RPS compliance to the CEC and their information is not included in this report.

RPS Progress and Status

This chapter uses historical annual data through December 31, 2023, to illustrate the state of the RPS program. The data was obtained from the 2024 Draft RPS Procurement Plans[10] and the 2023 RPS Annual Compliance Reports[11] of all retail sellers, including the IOUs, SMJUs, CCAs, and ESPs. This report provides an update on the retail sellers' progress toward meeting RPS requirements for 2023, which is within the 2021-2024 compliance period, and highlights retail sellers' progress toward annual RPS procurement targets and RPS procurement requirements for the entire compliance period. Greater detail regarding the compliance process is provided in this report's Compliance and Enforcement section and Appendix B.

Current Renewable Portfolios

All electricity retail sellers had an annual target to serve at least 41.3 percent of their electric load with RPS-eligible resources by December 31, 2023.[12] In general, most retail sellers reported either meeting or exceeding the 41.3 percent interim RPS target.[13] Additionally, almost all met their 2017–2020 compliance period requirements of 33 percent.[14] Figure 1 below shows statewide progress towards meeting the 2030 60 percent RPS requirements.[15] This figure and similar figures below plot the renewable energy credits (RECs) produced from online generation and generation yet to come online, as well as REC quantities from expiring contracts and retail sellers' REC sales to other market participants, all of which are compared against the RPS requirement.

10 Each year, retail sellers are required to submit their RPS Procurement Plans to the CPUC for approval. Draft 2024 RPS Procurement Plans were submitted in July 2023.

11 Retail sellers are required to submit preliminary RPS Compliance Reports each year on August 1 to demonstrate progress towards meeting their RPS requirements.

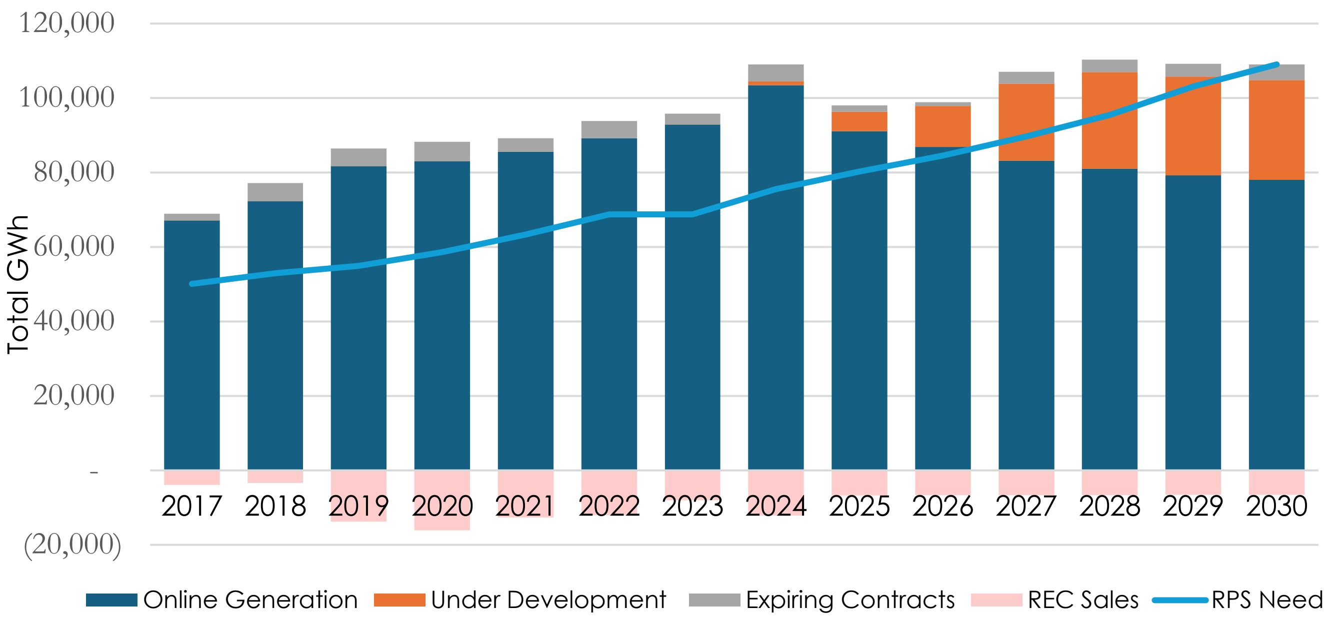
12 See D.19-06-023.

13 Compliance with California's RPS program is determined by multi-year compliance periods.

14 *See* the Compliance and Enforcement section for more information.

15 *See* the 2014 Administrative Law Judge Ruling on Renewable Net Short for full definitions of Online Generation, Under Development, and Expiring Contracts: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M091/K331/91331194.PDF.

Figure 1: Aggregated Retail Seller Progress Towards 60% RPS (2017-2030)



CPUC 2024 RPS Annual Report (November 2024)

Figure 1: Aggregated Retail Seller Progress Towards 60% RPS (2017-2030)
Data Source: All Retail Sellers' 2024 Draft RPS Procurement Plans (July 2024), Renewable Net Short Calculations

Investor-Owned Utilities (IOUs)

The IOUs serving electric load in California are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

PG&E's service territory spans from Santa Barbara to Shasta Counties, SCE's territory spans from Riverside to Mono Counties, and SDG&E serves San Diego County and southern Orange County.[16] The three IOUs are on track to meet their 60 percent 2030 RPS procurement mandate. Some IOUs have procured and contracted to be on track to either meet or surpass the 2024 annual RPS percentage target of 44 percent, while others are expected to utilize banked excess procurement from past years. Table 1 illustrates their 2023 procurement percentages towards this requirement.[17]

16 For more information on California electric utility service areas, see the CEC's California Energy Maps website: https://cecgis-caenergy.opendata.arcgis.com/documents/4d87af4f27054544bb3be7fe03b9cd9c/explore.

17 Based on their annual Draft 2024 RPS Procurement Plans, as well as Compliance Reports filed with the CPUC in 2024.

Table 1: Investor-Owned Utilities' RPS Procurement Percentages for 2023	
Pacific Gas and Electric	41%
Southern California Edison	41%
San Diego Gas & Electric	48%

Table 1: Investor-Owned Utilities' RPS Procurement Percentages for 2023
Data Source: IOUs' 2024 Draft RPS Procurement Plans (July 2024), Renewable Net Short Calculations

In contrast with previous compliance periods, the three IOUs no longer all forecast having excess procurement for the next three years. This change is primarily due to portfolio optimization efforts, primarily the Voluntary Allocation and Market Offer (VAMO) process and some increasing transportation electrification load but forecasts have also been impacted by procurement to meet other requirements such as those added by SB 1020 (Laird, Chapter 361, Statues of 2022) and the Integrated Resource Planning (IRP) proceeding. IOUs expecting shortfalls may choose to meet compliance requirements through additional procurement or by applying excess renewable electricity banked from procurement in prior years. Not all IOUs are facing the same degree of shortfall, however, and some may still choose to further optimize their portfolio through sales of renewable electricity and associated RECs[18] to other retail sellers, such as CCAs, ESPs, or POUs.

Figure 2 below uses the most current annual data to illustrate the actual and forecasted progress the IOUs have made toward meeting the 60 percent RPS mandate by 2030. Generation forecasts from projects "Under Development" are risk-adjusted to account for a certain degree of project failure.[19] The "Expiring Contracts" data represent the amount of generation associated with facilities that will no longer have a Power Purchase Agreement (PPA) with one of the IOUs.

18 *See* Appendix D: Glossary and Terms for the full definition of a renewable energy credit (REC).
19 Failure rate assumptions are provided by the IOUs in their renewable net short calculation provided with their Draft Annual RPS Procurement Plans.

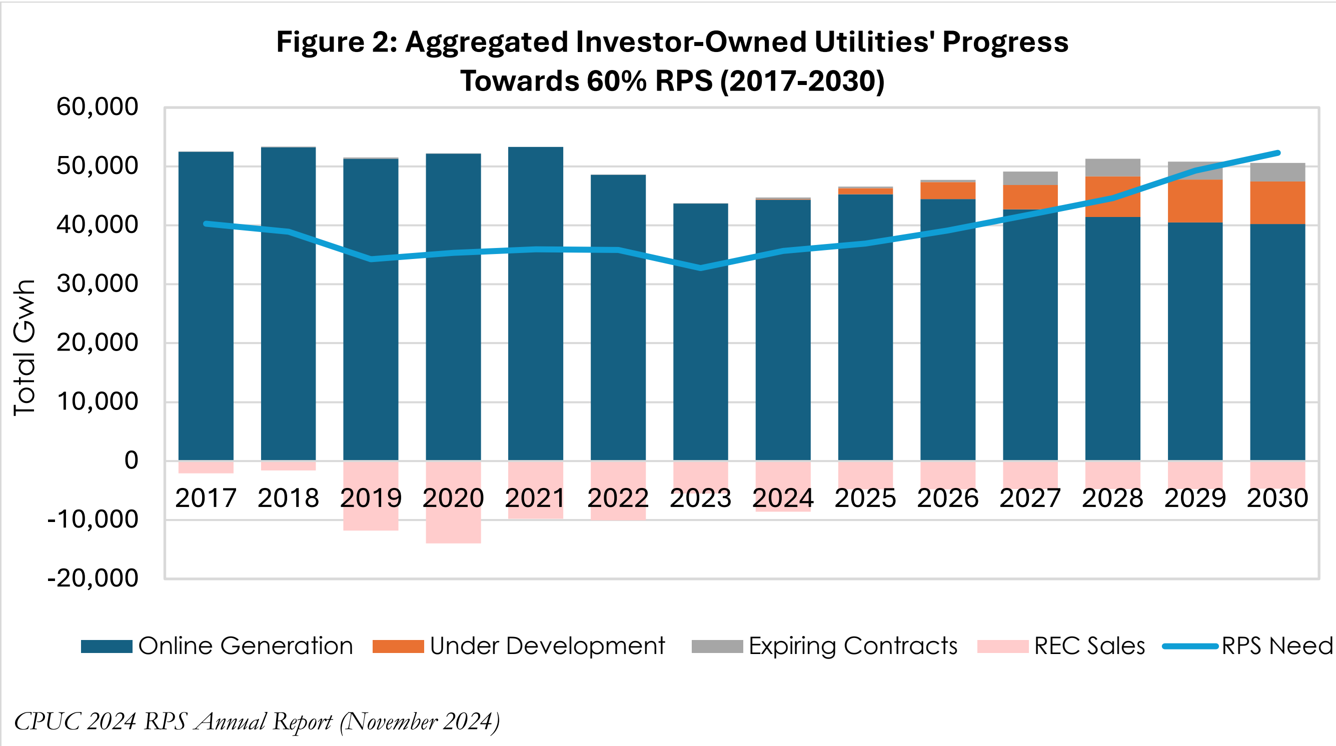


Figure 2: Aggregated Investor-Owned Utilities' Progress Towards 60% RPS (2017-2030)
Data Source: IOUs' 2024 Draft RPS Procurement Plans (July 2024), Renewable Net Short Calculations

The IOUs forecast that they will comply with RPS requirements through a combination of online generation from existing contracts and/or banked RECs, but some already report physical deficits which will make the use of the bank a necessity in the 2025-2027 compliance period. Given that the IOUs have historically had significant excess eligible RPS procurement to apply in later years, they did not conduct annual RPS procurement solicitations from 2016 to 2022. In 2023, both SCE and PG&E held solicitations, but neither resulted in any contracts. All three IOUs have procured for IRP mid-term reliability requirements during this time period, however, including for some RPS-eligible resources.[20]
Table 2 includes aggregate data[21] to demonstrate the IOUs' actual procurement and forecasted RPS procurement percentages. The data shows that the IOUs met their 2023 RPS compliance target and will

20 The CPUC must approve solicitations outlined in an IOU's annual RPS Procurement Plan in a Decision. D.23-12-008 approved retail sellers' 2023 RPS Procurement Plans.

21 Each retail seller must file its RPS Procurement Plan and Compliance Report annually. Renewable procurement data is not automatically confidential but may be claimed as such through a formal filing. In the formal confidentiality filing, the retail seller must justify why the information should be treated as confidential by the CPUC. Generally, historical data should be public. For contracts requiring CPUC approval, RPS procurement price and contract terms become public 30 days after commercial operation date / energy delivery start date or 18 months from the date of CPUC approval, whichever comes first. For contracts that do not require CPUC approval, contract price and contract terms shall be public 30 days after the commercial operation date/energy delivery start date or eighteen months after the contract execution date, whichever comes first. See the CPUC's Decision on Confidentiality (D.21-11-029) for more information: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M424/K520/424520189.PDF.

have procured approximately 41 percent of their total retail sales as RPS-eligible energy by the end of 2023. The forecasted RPS percentages of the aggregated IOUs decreases from 41 percent in 2023 to 35 percent in 2024, largely due to VAMO allocations despite load migration to CCAs in the IOUs' territories.

Table 2: Aggregated Actual and Forecasted Investor-Owned Utilities' Gross RPS Percentages (excludes bank usage) for Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric										
Compliance Period 2017–2020				Compliance Period 2021–2024				Compliance Period 2025–2027		
2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
34%	39%	36%	36%	43%	41%	41%	35%	47%	48%	47%

Table 2: Aggregated Actual and Forecasted Investor-Owned Utilities' Gross RPS Percentages (excludes bank usage) for Pacific Gas and Electric, Southern California Edison, and San Diego Gas & Electric
Data Source: IOUs' 2024 Draft RPS Procurement Plans (July 2024), Renewable Net Short Calculations

Although Table 2 shows a shortfall for the 2021-2024 compliance period, the table reflects only physical deliveries and does not include the impact of banked RECs. Including allowable usage of banked RECs, the IOUs forecast exceeding the State mandates through 2027.

Small and Multi-Jurisdictional Utilities (SMJUs)

The SMJUs[22] serving electric load in California are Bear Valley Electric Service, Inc. (BVES), Liberty Utilities, LLC[23] (Liberty), and PacifiCorp.[24] BVES provides electricity service to the Big Bear Valley in the San Bernardino Mountains and Liberty serves areas located in and around the Lake Tahoe Basin. PacifiCorp is a multi-jurisdictional utility that provides service in several states and to four Northern California counties: Del Norte, Modoc, Siskiyou, and Shasta.

As illustrated in Figure 3, the aggregate SMJU data indicates that the SMJUs are generally on target to meet the 2021–2024 compliance period requirements. Figure 3 also shows that the SMJU procurements are in line with the annual interim target of 41.25 percent for 2023 as well as the 2024 annual RPS interim target of 44 percent. However, in their most recent Compliance Reports, two out of the three SMJUs reported procurement positions falling short of compliance period 2021-2024 requirements, though these shortfalls are small.

As noted earlier, statutory RPS requirements utilize multi-year compliance periods, so this does not mean that any SMJUs will ultimately be out of compliance for the 2021-2024 compliance period – in fact, the SMJUs have historically met their requirements towards the end of the compliance period. Also, SMJUs'

22 SMJUs are also investor-owned utilities but are considered either small or multijurisdictional and have different rules per Public Utilities Code §§ 399.17 and 399.18.
23 Formerly CalPeco Electric.
24 d/b/a Pacific Power.

RPS procurements do not need to meet the Portfolio Balance Requirement rules, and they may procure unlimited unbundled REC contracts which tend to be from existing facilities and have quicker transaction times. For example, Figure 3 shows how SMJUs' renewable generation increased significantly in 2020, likely to meet their requirements for the 2017-2020 compliance period. Nevertheless, the remaining time in the current compliance period is short, so any final procurements would have to be well underway.

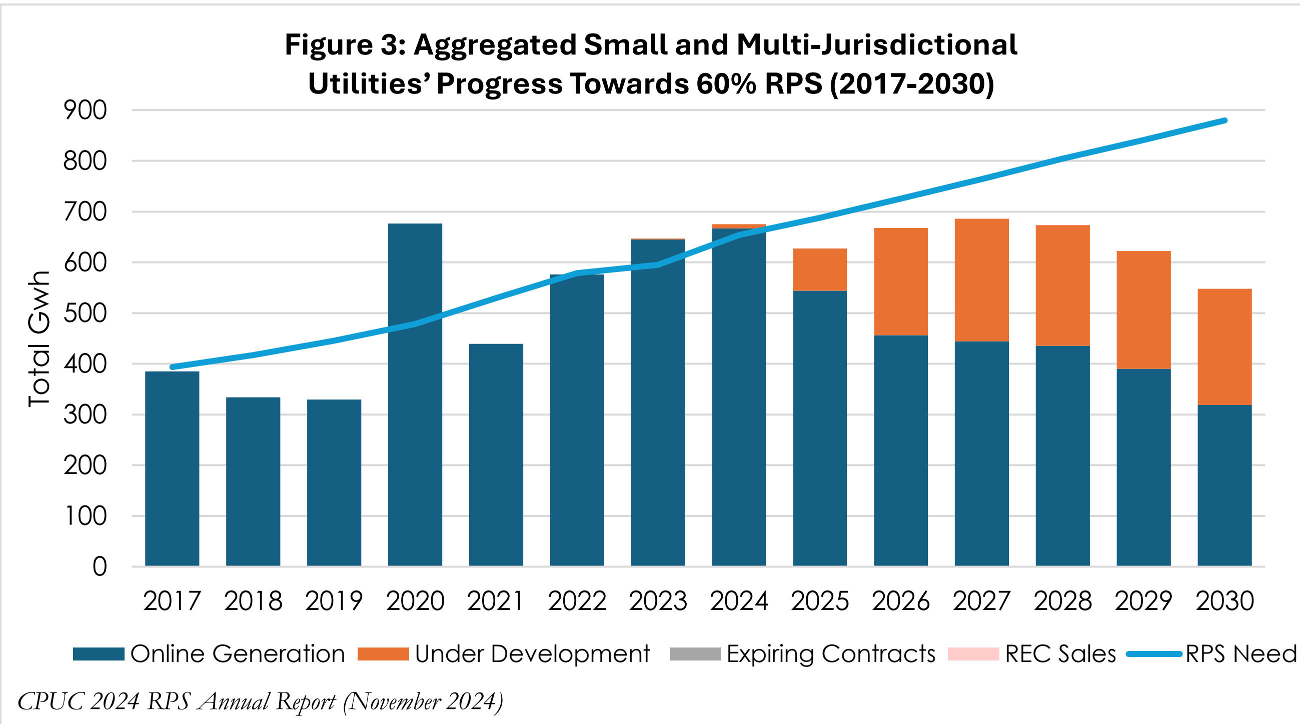


Figure 3: Aggregated Small and Multi-Jurisdictional Utilities' Progress Towards 60% RPS (2017-2030)
Data Source: SMJUs' 2024 Draft RPS Procurement Plans (July 2024), Renewable Net Short Calculations

Looking forwards, SMJUs are currently showing a continued need for procurement in the next compliance period, as illustrated in Table 3.

Table 3 shows aggregate SMJU data for their actual and forecasted RPS procurement percentages.[25]

25 The CPUC has aggregated RPS procurement data for confidentiality purposes, as reporting individual percentages would disclose market sensitive information.

Table 3: Aggregated Actual and Forecasted Small and Multi-Jurisdictional Utilities' Gross RPS Percentages for Bear Valley Electric Service, Liberty Utilities, and PacifiCorp[26]										
Compliance Period 2017–2020				Compliance Period 2021–2024				Compliance Period 2025–2027		
2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
26%	23%	23%	47%	32%	41%	47%	46%	43%	46%	47%

Table 3: Aggregated Actual and Forecasted Small and Multi-Jurisdictional Utilities' Gross RPS Percentages for Bear Valley Electric Service, Liberty Utilities, and PacifiCorp
Data Source: SMJUs' 2024 Draft RPS Procurement Plans (July 2024), Renewable Net Short Calculations

Community Choice Aggregators (CCAs)

CCAs are local government entities that are certified by the CPUC to procure electricity on behalf of their communities instead of being served by the IOUs.[27] The CCAs play an increasingly significant role in meeting the State's electric reliability, renewable energy, and GHG reduction goals. In 2023, 25 CCAs[28] operated in California and collectively served 36 percent of the total electric load within CPUC's jurisdiction.[29] All but four of the operating CCAs procured at or above the 2023 annual RPS target, as shown in Table 5.

Table 4 uses aggregated CCA data to show actual and forecasted RPS procurement percentages in the current and next compliance period.[30]

Table 4: Aggregated Actual and Forecasted Community Choice Aggregators' Gross RPS Percentages[31]										
Compliance Period 2017–2020				Compliance Period 2021–2024				Compliance Period 2025–2027		
2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
52%	50%	53%	49%	47%	55%	59%	69%	58%	60%	69%

Table 4: Aggregated Actual and Forecasted Community Choice Aggregators' Gross RPS Percentages
Data Source: CCAs' 2024 RPS Draft Procurement Plans (July 2024), Renewable Net Short Calculations

26 Gross RPS percentages reflect physical deliveries only – does not include the usage of banked RECs.
27 Assembly Bill (AB) 117 (Migden, Chapter 838, Statues of 2002) allows local governments to form Joint Powers Authorities to establish community choice energy programs.
28 *See* Table 5 for a list of operating CCAs and their first year of operation.
29 Retail Sellers' Annual RPS Compliance Reports, August 2024.
30 The aggregated RPS compliance percentages are adjusted for CCA launch years and include data from all 25 registered CCAs.
31 Gross RPS percentages reflect physical deliveries only – does not include the usage of banked RECs.

As is the case with all CPUC-jurisdictional retail sellers, CCAs submit annual compliance filings to the CPUC demonstrating their progress toward annual RPS procurement targets. While these forecasts are not determinative of their compliance status, they offer insight into retail sellers' ability to meet RPS requirements. The annual RPS Compliance Reports indicate that most CCAs will need to procure additional renewable resources to meet the 60 percent RPS target by 2030.[32]

Figure 4 illustrates the actual and forecasted progress the CCAs have made toward meeting the RPS requirements in aggregate, where they are forecast to exceed RPS targets during the remainder of the 2021-2024 compliance period. In aggregate, the CCAs are contracted to exceed their forecasted 2024 and 2025 targets. However this aggregate is impacted by a common CCA objective of exceeding RPS mandates, and this over procurement obscures the risk that some CCAs have of not meeting RPS requirements.

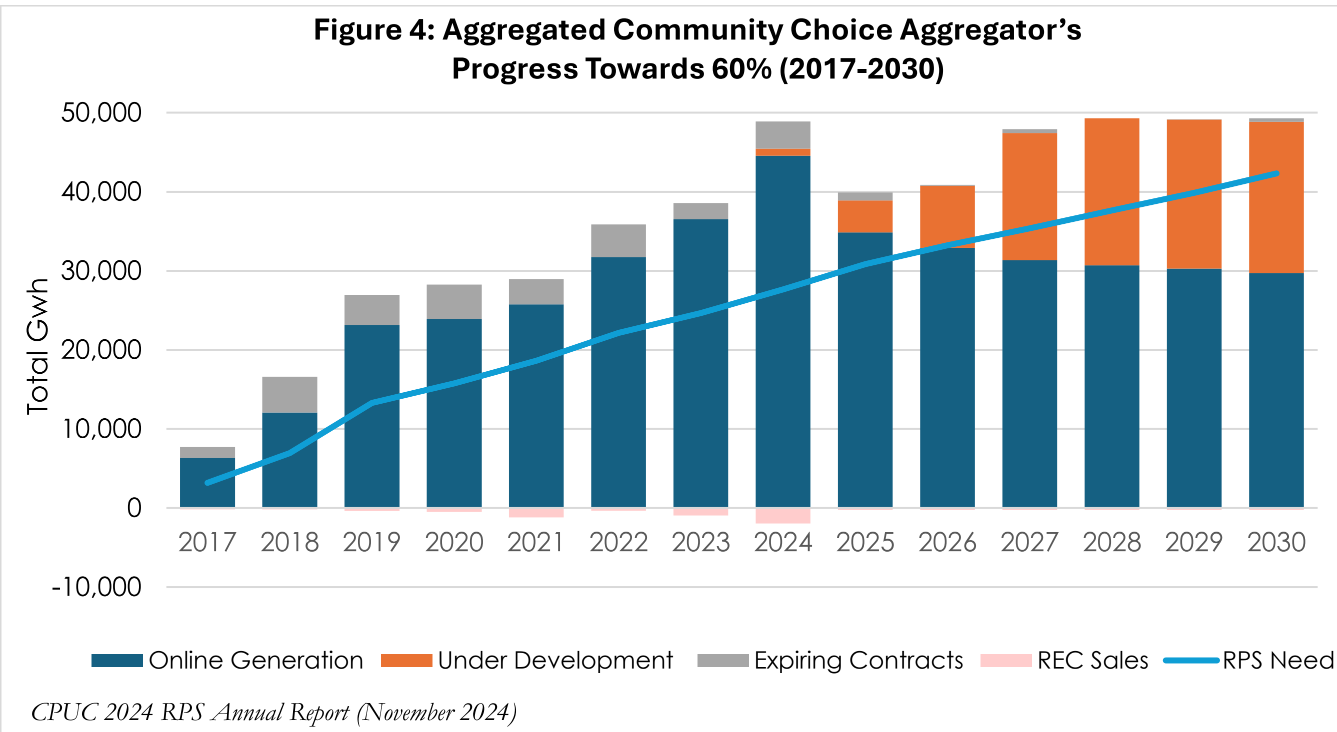


Figure 4: Aggregated Community Choice Aggregator's Progress Towards 60% (2017-2030)
Data Source: CCAs' 2024 Draft RPS Procurement Plans (July 2024), Renewable Net Short Calculations

In 2023, the operational CCAs served a total of approximately 60,000 GWh of load[33] and had an aggregated RPS position of 59 percent. The CCAs' generation has increased to keep pace with RPS requirements through 2024, even exceeding the 2024 forecasted target. The CCAs' forecasted renewable generation relies heavily on projects that remain under development and must come online, as aggregate online generation begins to decline past 2024, with only three of the 25 CCAs forecasting an increase in renewable generation

32 *See* Table 5 for a breakdown of RPS position by each individual operating CCA.
33 Calculated from 2023 Annual RPS Compliance Reports

from online projects in 2025, while 22 of the CCAs forecast a decrease. Table 5 below shows the actual positions of individual CCAs that were operational in 2023 and their forecasted positions for 2024 and 2025.

Table 5: Annual RPS Position of CCAs (%)

First Year Serving Load	CCA	Actuals		Forecast	
		2022	2023	2024	2025
2010	Marin Clean Energy	62%	68%	84%	62%
2014	Sonoma Clean Power	53%	54%	-	-
2015	Lancaster Choice Energy	39%	63%	73%	35%
2016	Peninsula Clean Energy	51%	51%	63%	67%
2016	CleanPowerSF	63%	60%	-	-
2017	Apple Valley Choice	30%	56%	43%	42%
2017	Pico Rivera	50%	49%	43%	40%
2017	Redwood Coast Energy Authority	49%	30%	59%	73%
2017	Silicon Valley Clean Energy	53%	44%	-	-
2018	Valley Clean Energy Alliance	18%	58%	73%	73%
2018	Central Coast Community Energy	37%	32%	-	-
2018	San Jacinto Power	37%	51%	46%	46%
2018	Rancho Mirage Energy Authority	39%	51%	41%	40%
2018	Clean Power Alliance	53%	73%	-	-
2018	Ava Community Energy	60%	68%	-	-
2018	Pioneer Community Energy	48%	44%	47%	44%
2018	San José Clean Energy	60%	57%	65%	62%
2018	King City Community Power	39%	41%	-	-
2020	Pomona Choice Energy	39%	48%	39%	35%
2020	Desert Community Energy	20%	80%	-	-
2021	Clean Energy Alliance	60%	52%	57%	38%

Table 5: Annual RPS Position of CCAs (%)					
First Year Serving Load	**CCA**	**Actuals**		**Forecast**	
		2022	**2023**	**2024**	**2025**
2021	San Diego Community Power	59%	59%	-	-
2021	Santa Barbara Clean Energy	50%	50%	37%	37%
2022	Energy for Palmdale's Independent Choice	39%	35%	47%	49%
2022	Orange County Power Authority	103%	84%	-	-

Table 5: Annual RPS Position of Community Choice Aggregators (%)
Data Source: CCA Draft RPS Procurement Plans (July 2024), CCA RPS Compliance Reports (August 2024). Forecast amounts of "-" indicate redacted information because these CCAs requested confidential treatment of their forecasted RPS position per CPUC D.06-06-066, as modified.

Electric Service Providers (ESPs)

ESPs serve customers in the Direct Access (DA) program.[34] ESPs currently serve approximately 16 percent or 26,000 GWh of electricity load within the CPUC's jurisdiction.[35]

Table 6 provides aggregate actual and forecasted RPS procurement percentages of ESPs, and it shows that in aggregate the ESPs met the 2023 annual RPS interim target of 41.25 percent, although this is distributed unevenly, and some ESPs will need to procure additional RPS energy to meet the 2021–2024 RPS compliance period requirements.

34 Direct Access (DA) service is retail electric service where customers have the choice to purchase electricity from an ESP, instead of from a regulated electric utility. For more information on DA, visit https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/electric-service-provider-list-and-registration-information.

35 *See* Appendix E for a list of active ESPs.

Table 6: Aggregate Actual and Forecasted ESPs' Gross RPS Percentages[36]										
Compliance Period 2017–2020				Compliance Period 2021–2024				Compliance Period 2025–2027		
2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
34%	28%	30%	29%	26%	31%	46%	53%	41%	40%	39%

Table 6: Aggregate Actual and Forecasted Electric Service Providers' Gross RPS Percentages
Data Source: ESPs' 2024 Draft RPS Procurement Plans (July 2024)

Though ESPs are required to file both RPS Compliance Reports and Procurement Plans, some do not go into as great of detail in describing their long-term plans for renewable procurement. The ESPs' forecasted procurement percentages are lower into the future because a substantial amount of the ESPs' RPS procurement are short-term contracts, but the amount of long-term contracts are increasing with the 65 percent long-term requirement that started in the 2021-2024 compliance period.

As illustrated in Figure 5, the aggregated ESP data indicates that ESPs are roughly in line with the RPS requirements in the 2021–2024 compliance period. However, there is a great deal of variability between ESPs with about half reporting in their 2023 Compliance Report a need for additional procurement. This need for procurement continues onward, with ESPs collectively needing significant procurement to meet the RPS requirements in the compliance periods for 2025-2028 and beyond.

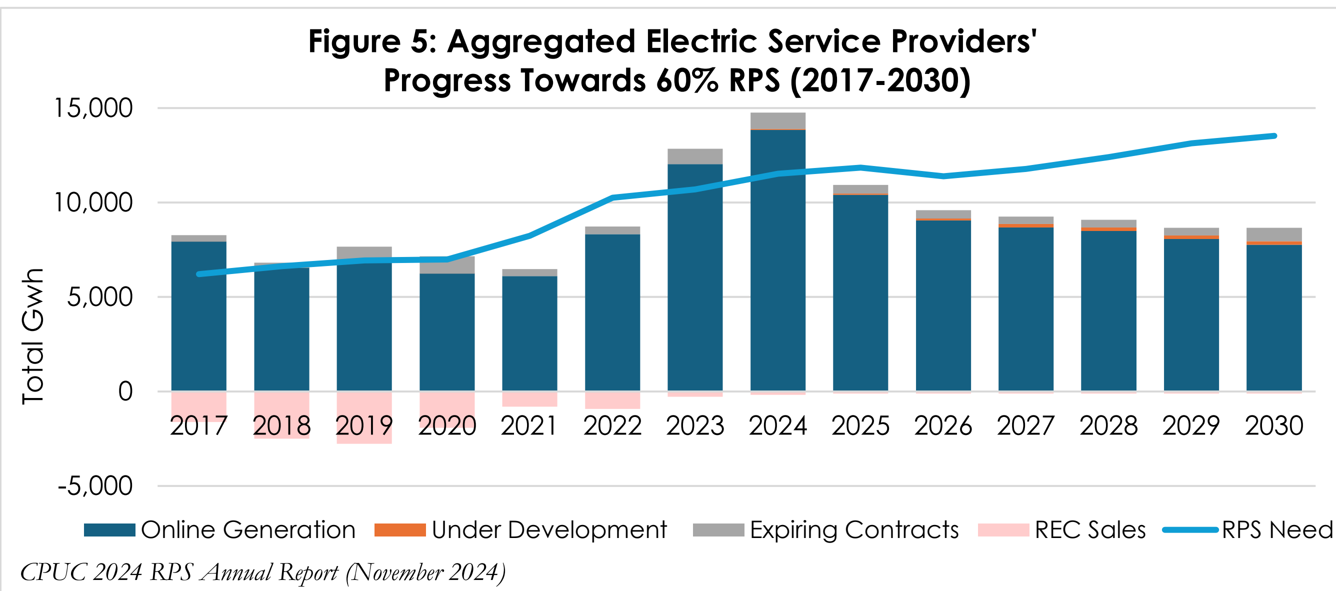


Figure 5: Aggregated Electric Service Providers' Progress Towards 60% RPS (2017-2030)
Data Source: ESPs' 2024 Draft RPS Procurement Plans (July 2024), Renewable Net Short Calculations

36 Gross RPS percentages reflect physical deliveries only – does not include the usage of banked RECs.

Renewable Technology Mix

Resource diversity can contribute to achieving a balanced and reliable energy generation portfolio.[37] Since the inception of the RPS program in 2002, the renewable technology mix of the State's energy portfolio has become increasingly diversified. A robust mix of renewable technologies will aid in the transition to a zero-carbon electricity portfolio by 2045, which is crucial for meeting the State's climate and emissions reduction goals.

Investor-Owned Utilities (IOUs)

As shown below in Table 7, the IOUs have procured a diverse mix of renewable energy resources including wind, solar thermal, solar photovoltaic (PV), geothermal, bioenergy, small hydroelectric facilities, and even some conduit hydro to meet the requirements of the RPS program.[38] In 2023, the majority of the IOUs' RPS portfolios were comprised of solar and wind technologies.

Table 7: Portfolio Percentages of 2023 RPS Mix for IOUs

	Bioenergy	Geothermal	Small Hydro[39]	Conduit Hydro[40]	Solar PV	Solar Thermal	Wind
PG&E	8%	1%	7%	-	46%	11%	28%
SCE	<1%	13%	2%	<0.1%	48%	1%	36%
SDG&E	1%	-	-	<1%	47%	-	51%

Table 7: Portfolio Percentages of 2023 RPS Mix for IOUs
Data Source: IOUs' Annual RPS Compliance Reports (August 2024)

Small and Multi-Jurisdictional Utilities (SMJUs)

In 2023, the SMJUs collectively procured a wide variety of resources, though the mix varied widely by SMJU. As depicted in Table 8 below, BVES procured RECs primarily from wind resources supplemented by solar in 2023, whereas Liberty was balanced between solar and geothermal, with a little

37 *See* Public Utilities Code § 399.11(b) for a list of the benefits the RPS program is intended to provide to California, among which is renewable resource diversity.
38 The technology category of "Bioenergy" consists of biomass, biogas, biodiesel, landfill gas, and municipal solid waste.
39 Small Hydro projects are defined as hydroelectric facilities that are under 30 MW in capacity by the CEC's RPS Eligibility Guidebook.
40 Conduit Hydro facilities use the hydroelectric potential of an existing man-made conduit that is operated to distribute water and must have a facility capacity of 30 MW or less to be considered RPS-eligible.

bioenergy. PacifiCorp had the most diverse renewable energy portfolio mix with six different technologies in its portfolio,[41] with most of its renewables being wind and solar.

Table 8: Portfolio Percentages of 2023 RPS Mix for SMJUs						
	Bioenergy	Geothermal	Small Hydro	Conduit Hydro	Solar PV	Wind
Bear Valley Electric Service	-	-	-	-	29%	71%
Liberty Utilities	1%	40%	-	-	58%	-
PacifiCorp	11%	1%	12%	<0.1%	28%	48%

Table 8: Portfolio Percentages of 2023 RPS Mix for SMJUs
Data Source: SMJUs' Annual RPS Compliance Reports (August 2024)

Community Choice Aggregators (CCAs)

In 2023, the majority of the CCAs' RPS portfolios were comprised of wind and solar resources, but many also included significant amounts of bioenergy, geothermal, and to a lesser degree small hydroelectric resources. Table 9 illustrates the renewable energy portfolio mixes of the CCAs that operated in California in 2023.

Table 9: Portfolio Percentages 2023 RPS Mix for CCAs							
	Bioenergy	Geothermal	Small Hydro	Conduit Hydro	Solar PV	Solar Thermal	Wind
Apple Valley Choice Energy	15%	4%	<1%	-	21%	-	59%
Ava Community Energy	13%	2%	2%	-	36%	-	46%
Central Coast Community Energy	2%	39%	1%	-	46%	-	11%
Clean Energy Alliance	-	-	-	-	49%	-	51%
Clean Power Alliance	3%	13%	2%	-	38%	<1%	44%
CleanPowerSF	1%	24%	1%	<0.1%	49%	-	25%
Desert Community Energy	-	1%	1%	-	50%	-	48%
Energy for Palmdale's Independent	-	30%	1%	-	34%	-	35%

41 PacifiCorp's California RPS portfolio refers to the portfolio of resources PacifiCorp uses to meet compliance with California's RPS program and does not refer to all resources in its portfolio.

Table 9: Portfolio Percentages 2023 RPS Mix for CCAs							
	Bioenergy	Geothermal	Small Hydro	Conduit Hydro	Solar PV	Solar Thermal	Wind
Choice							
King City Community Energy	-	-	-	-	79%	-	21%
Lancaster Choice Energy	14%	3%	<1%	-	38%	-	45%
Marin Clean Energy	3%	1%	11%	-	53%	-	31%
Orange County Power Authority	13%	17%	3%	-	34%	<1%	32%
Peninsula Clean Energy	-	26%	2%	-	34%	-	38%
Pioneer Community Energy	14%	10%	16%	-	31%	-	29%
Pico Rivera Innovative Municipal Energy	20%	1%	<1%	-	19%	-	60%
Pomona Choice Energy	16%	3%	<1%	-	11%	-	70%
Redwood Coast Energy Authority	67%	<1%	9%	-	10%	-	14%
Rancho Mirage Energy Authority	16%	1%	<1%	-	23%	<0.1%	60%
San Diego Community Power	12%	1%	1%	-	49%	-	37%
San Jacinto Power	15%	<1%	<1%	-	27%	-	58%
San José Clean Energy	2%	<1%	-	-	34%	1%	27%
Santa Barbara Clean Energy	-	<1%	3%	-	13%	<0.1%	83%
Silicon Valley Clean Energy	7%	34%	1%	-	29%	-	28%
Sonoma Clean Power	17%	40%	1%	-	16%	-	27%
Valley Clean Energy Alliance	-	3%	25%	-	72%	-	-

Table 9: Portfolio Percentages 2023 RPS Mix for CCAs
Data Source: CCAs' Annual RPS Compliance Reports (August 2024)

As Table 9 shows, CCAs vary widely in resource mix, with most showing a diversity in RPS procurement technologies.

Electric Service Providers (ESPs)

Table 10 illustrates the renewable energy portfolio mixes of the ESPs operating in California in 2023.

Table 10: Portfolio Percentages 2023 RPS Mix for ESPs						
	Bioenergy	**Geothermal**	**Small Hydro**	**Solar PV**	**Solar Thermal**	**Wind**
3 Phases Renewables	4%	1%	10%	79%	-	6%
BP Energy Retail	2%	-	-	69%	-	29%
Calpine Energy Solutions	5%	20%	12%	47%	-	16%
Calpine Power America	-	22%	-	78%	-	-
Commercial Energy of CA	3%	1%	2%	66%	-	27%
Constellation New Energy	1%	-	-	73%	-	26%
NRG (formerly Direct Energy Business)	4%	3%	1%	69%	-	23%
Pilot Power Group	<0.1%	19%	-	15%	-	66%
Shell Energy Solutions	1%	6%	2%	44%	-	48%
UC Regents	-	-	-	84%	-	16%

Table 10: Portfolio Percentages 2023 RPS Mix for ESPs
Data Source: ESPs' Annual RPS Compliance Reports (August 2024)

As Table 10 indicates, many ESPs have diverse RPS portfolios comprised of a variety of renewable technologies including bioenergy, geothermal, hydroelectric, solar, and wind. As with CCAs, ESPs procured the majority of their RECs from wind and solar, but only one ESP procured solely from these technologies.

Contracted Renewable Capacity

Since 2003, the three IOUs have contracted for over 19,803 MW of renewable capacity[42] under the RPS program. The CPUC must approve all new RPS capacity additions proposed by the IOUs and SMJUs but is not required to approve capacity additions for CCAs and ESPs. Accordingly, the data collected by the CPUC on approved capacity is primarily for the IOUs.

The approved RPS capacity shown in Figure 6 includes both in-state and out-of-state facilities that have contracted with the IOUs and have come online between 2003 and 2023. Most of the new facilities

42 Renewable capacity is defined as the maximum power generating capacity of power plants that use renewable energy sources to produce electricity.

procured for the RPS program are located in-state. Approximately 241 additional MW of renewables contracted by the IOUs are scheduled to come online in 2024.

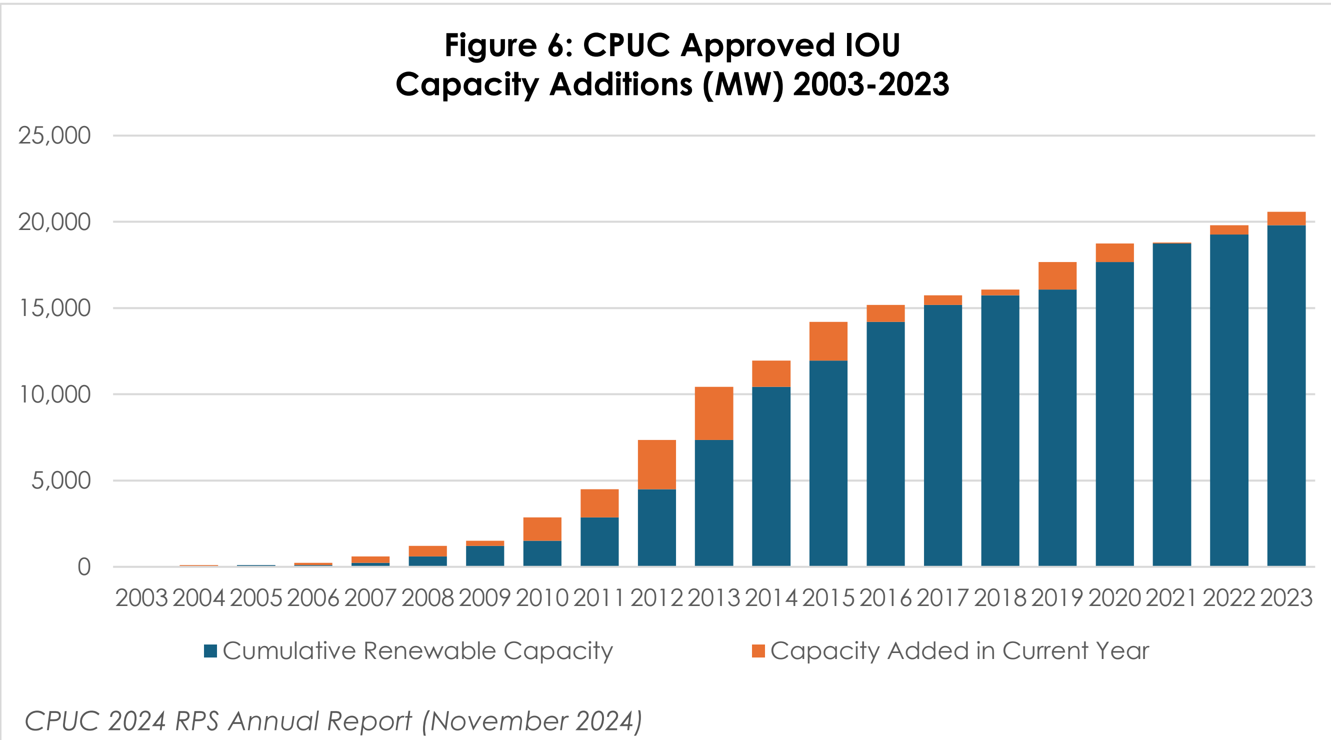


Figure 6: CPUC Approved IOU Capacity Additions (MW) 2003-2023
Data Source: CPUC RPS Database, September 2024

RPS Procurement Costs

To understand the impact that RPS procurement costs will have on ratepayers, the CPUC collects various pricing data to evaluate cost trends and analyzes rate impacts. The IOUs use competitive procurement mechanisms and a Least-Cost Best-Fit evaluation methodology[43] to procure renewable resources that provide the most value to their customers. Although the CPUC has not established cost limitations for RPS procurement, it uses the Integrated Resource Planning[44] (IRP) proceeding to identify the most cost-effective portfolio of resources to inform future procurement activities.

The overall contracted commitment in renewables by retail sellers in California has increased over time, which has contributed to the cost competitiveness of technologies, particularly solar and wind. Figure 7

43 The Least-Cost Best-Fit methodology is a valuation framework that the IOUs use for the rank ordering and selection of least-cost and best-fit renewable resources to comply with annual RPS obligations on a total cost basis.
44 For more information on the IRP proceeding (R.20-05-0023), visit https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning.

illustrates the average annual contract prices of new contracts executed each year for RPS eligible projects with capacities greater than 3 MW by technology category in cents per kilowatt-hour (¢/kWh) for retail sellers.

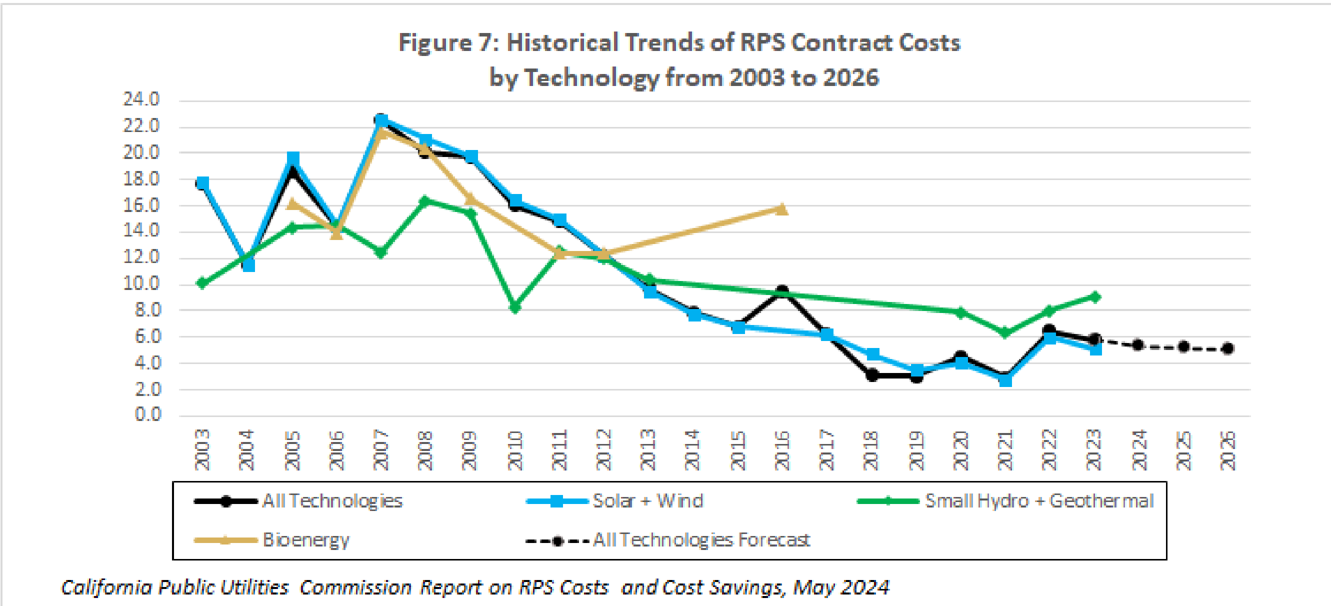


Figure 7: Historical Trends of RPS Contract Costs by Technology from 2003 to 2026

Figure 7[45] shows that RPS contract prices, in real dollars, decreased on average of 1.3 percent annually between 2007 and 2023 for the "all technologies" group. The overall downward trend in contract prices can be attributed to falling prices for wind and solar technologies, which together make up the majority of the IOUs' collective RPS generating capacity. To remove non-representational trends, contracts with a nameplate capacity of less than 3 MW and those reported as net cost instead of total contract price were not included in Figure 7.

The average price of IOU, CCA, and ESP contracts executed in 2023 was 5.8¢/kWh compared to 6.2¢/kWh in real-dollar value in 2022. Almost all procurement contracts with new facilities in 2023 were executed by CCAs. The average contract prices of recent periods have included notable purchases of higher cost renewable resource types such as geothermal. Continued supply chain impacts and inflation also likely impacted energy prices in recent periods. For more information on the costs of the RPS program, see the CPUC's 2024 Annual Report on RPS Costs and Cost Savings (Padilla Report).[46]

45 The average annual contract prices in Figure 7 are an average of the contracts executed that specific year by technology type and are not rolling averages of previous years.

46 https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/energy/rps/2024/2024-padilla-reportvfinal.pdf.

Renewable Procurement and Project Development

This chapter uses the most current procurement and contracting data available as of September 2024 for all retail sellers to evaluate the state of new renewable project development.

Contracting and New Projects in Development

Investor-Owned Utilities (IOUs)

The IOUs were authorized to hold RPS procurement solicitations in 2023 and 2024. They either did not hold RPS procurement solicitations or did not contract with new RPS projects. However, some RPS-eligible resource contracting was completed via IRP-directed procurement.

Table 11: New Renewables Projects with IOU Contracts COD 2024-2027

IOU	Technology	Capacity (MW)	County/ Location	Contract Term (Years)	COD
Pacific Gas and Electric	Solar PV	150	Kern, CA	15	2024
Pacific Gas and Electric	Solar PV	200	La Paz, AZ	15	2026
Pacific Gas and Electric	Solar PV	375	La Paz, AZ	15	2027
Pacific Gas and Electric	Solar PV	375	La Paz, AZ	15	2027
Pacific Gas and Electric	Solar PV	75	Maricopa, AZ	15	2025
Southern California Edison	Solar PV	20	Kern, CA	12	2025
Southern California Edison	Solar PV	20	Kern, CA	20	2024
Southern California Edison	Geothermal	70	Millard, UT	15	2027
Southern California Edison	Solar PV	150	San Bernardino, CA	15	2027
Southern California Edison	Solar PV	84.5	Fresno, CA	20	2025
Southern California Edison	Solar PV	20	Kern, CA	15	2025
Southern California Edison	Solar PV	200	La Paz, AZ	15	2026

Table 11: New Renewables Projects with IOU Contracts COD 2024-2027					
IOU	**Technology**	**Capacity (MW)**	**County/ Location**	**Contract Term (Years)**	**COD**
Southern California Edison	Solar PV	100	La Paz, AZ	15	2026
Southern California Edison	Solar PV	225	La Paz, AZ	15	2026
San Diego Gas & Electric	Solar +Storage	113.5	Fresno, CA	15	2025
San Diego Gas & Electric	Solar + Storage	65	Nye, NV	15	2026
Total MW		2,243			

Table 11: New Renewables Projects with IOU Contracts COD 2024-2027
Data Source: IOUs' Draft RPS Procurement Plans (July 2024), IOUs' Annual RPS Compliance Reports (August 2024)

Renewable Energy Credit (REC) Sales

Due to the IOUs' forecasted excess RPS procurement, the CPUC authorized the IOUs to hold REC sales solicitations in 2019, 2020, 2021, 2022 and 2023 to sell RPS energy from their portfolios.[47] The IOUs' long RPS position is a result of forecasted excess RPS procurement and customer load departure. REC sales solicitations provide IOUs with the opportunity to optimize their portfolios as well as provide renewable resources for other retail sellers. The IOUs' REC sales also offer a path for smaller or newer retail sellers to procure quantities to meet their RPS compliance needs.

All three of the IOUs have held REC sales solicitations in 2019, 2020, 2021, 2022, and 2023 and have requested CPUC approval to conduct additional REC sales solicitations in 2024. Additionally, the IOUs have allocated "slices" of their entire Power Charge Indifference Adjustment (PCIA)-eligible RPS portfolios as part of the Voluntary Allocation and Market Offer (VAMO) process. The IOUs completed their Voluntary Allocation contracting on July 29, 2022, approved on November 3, 2022, and executed the remaining Market Offer contracts in early 2023. With the VAMO process completed, we see REC sales have diminished greatly in 2023, reflecting better optimization in the IOUs' RPS portfolios.

In 2023, PG&E, SCE, and SDG&E executed a total of 15 REC sales contracts. Table 12 below shows REC sales solicitation summaries by IOU.

47 *See* D.19-12-042.

Table 12: IOU REC Sales Contracts Approved by the CPUC								
	PG&E		SCE		SDG&E		Totals	
	Contracts	GWh	Contracts	GWh	Contracts	GWh	Contracts	GWh
2021	9	2,107	32	7,986	1	159	**42**	**10,252**
2022	15	2,936	30	5,905	2	1,180	**47**	**10,021**
2023	-	-	4	432	11	824	**15**	**1,256**

Table 12: IOU REC Sales Contracts Approved by the CPUC
Data Source: CPUC RPS Database, September 2024

As Figure 8 below shows, the IOUs' REC sales solicitations have resulted in a stabilization of excess procurement bank size. In aggregate, the IOUs have sold approximately 25,000 GWh of RPS energy from their portfolios from 2020 to 2023 and will sell additional RPS energy in 2024 and 2025 from authorized REC sales and approved Market Offer contracts.

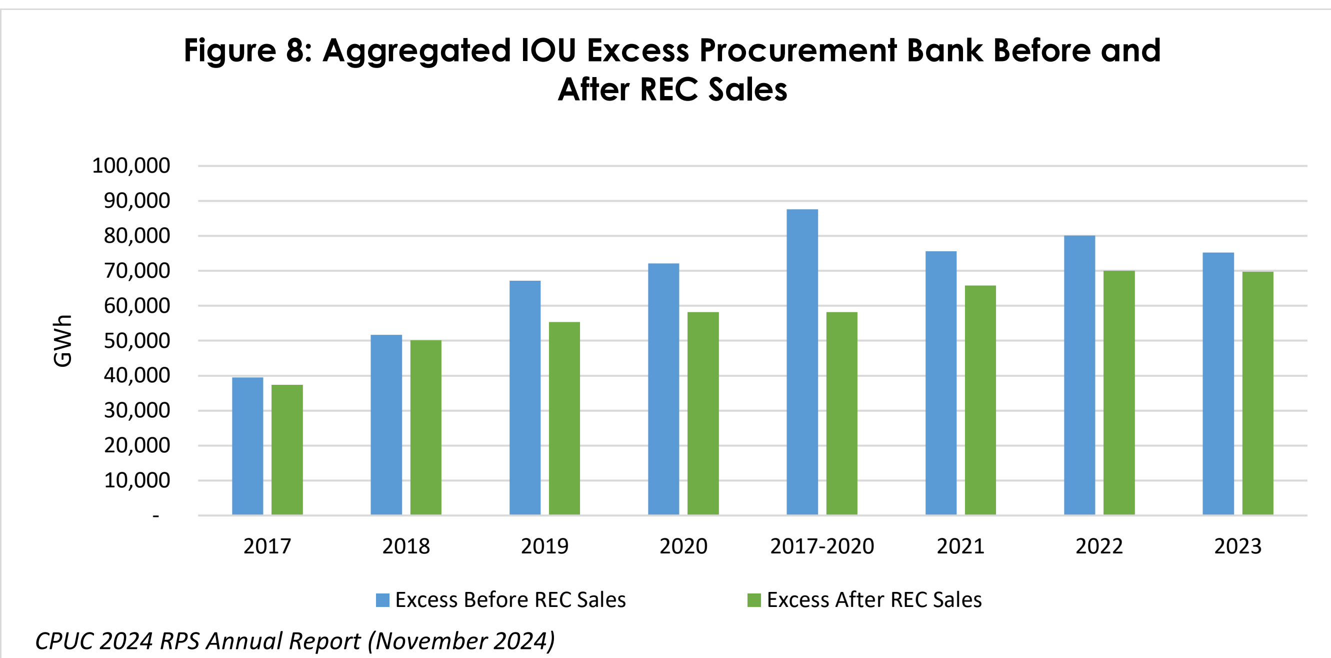


Figure 8: Aggregated IOU Excess Procurement Bank Before and After REC Sales
Data Source: IOUs' 2024 Draft Procurement Plans, Renewable Net Short calculations

Small and Multi-Jurisdictional Utilities (SMJUs)

Liberty did not execute any contracts to procure eligible renewable energy as part of its 2023 RPS Procurement Plan. BVES submitted an application (A.24-05-020) to the Commission for approval of a utility-owned solar project and a battery storage project near Big Bear City in San Bernardino County. Both are expected to reach Commercial Operation Date around year-end 2026. The solar project is expected to have a nameplate capacity of 5 MW, and the battery project will be a 5 MW/20 MWh battery energy storage system. On August 22, 2024, the CPUC approved PacifiCorp's procurement of long-term unbundled renewable energy credits.

The SMJUs may procure unlimited unbundled REC contracts which are normally from existing facilities and have quicker transaction times; thus, historically the SMJUs have tended to meet their requirements towards the end of the compliance period. As shown in Figure 3 in the RPS Progress and Status section, the SMJUs procurements are on course with the annual interim target of 41.25 percent for 2023 and the 2024 annual RPS interim target of 44 percent.

Refer to the RPS Progress and Status section for more information.

Community Choice Aggregators (CCAs)

To date, 15 CCAs have executed long-term contracts with new utility-scale[48] renewable projects that are in development. The data in the tables below include projects with future online dates and does not represent an exhaustive list of all CCA projects that have been contracted for and built over the last decade. Table 13 shows the in-state and in-development renewable energy projects contracted by CCAs with commercial online dates (CODs) in 2024 and 2025. Of the contracts listed, about 92 percent are for new solar PV resources, many of which include hybrid or co-located storage.

Table 13: New California Renewables Projects Contracted by CCAs with COD in 2024–2025

CCA	Technology	Capacity (MW)	County/ Location	Contract Term (Years)	COD
Central Coast Community Energy	Solar PV	20	Tulare	15	2024
Central Coast Community Energy	Solar PV	70	Kern	12	2024
Central Coast Community Energy	Solar PV	63	Fresno	15	2024
Central Coast Community Energy	Solar + Storage	120	Kern	20	2025
Clean Power Alliance	Solar PV	24	Kern	20	2025
Clean Power Alliance	Solar PV	89	Kern	15	2024

48 Utility-scale projects refer to contract capacities of 20 MW or greater.

Table 13: New California Renewables Projects Contracted by CCAs with COD in 2024–2025					
CCA	**Technology**	**Capacity (MW)**	**County/ Location**	**Contract Term (Years)**	**COD**
Clean Power Alliance	Solar PV	480	Tulare	15	2024
Clean Power Alliance	Solar PV	94	Riverside	15	2024
Clean Power Alliance	Solar PV	450	Riverside	15	2024
Clean Power Alliance	Solar PV	24	Kern	20	2025
East Bay Community Energy	Solar PV	125	Riverside	15	2024
East Bay Community Energy	Solar PV	100	Fresno	20	2024
Marin Clean Energy	Solar + Storage	100	Kern	15	2025
Peninsula Clean Energy	Solar PV	100	Riverside	15	2024
Pioneer Community Energy	Solar PV	200	Kern	14	2024
Redwood Coast Energy Authority	Solar PV	100	Kern	15	2024
San Diego Community Power	Solar PV	137	Imperial	20	2024
San Diego Community Power	Solar PV	42	Imperial	20	2025
San Jose Clean Energy	Solar PV	100	Fresno	20	2024
San Jose Clean Energy	Solar PV	48	Kern	15	2025
Silicon Valley Clean Energy	Solar PV	80	Kern	20	2025
Silicon Valley Clean Energy	Solar PV	62	Fresno	15	2025
Silicon Valley Clean Energy	Solar PV	100	Riverside	15	2024
Sonoma Clean Power Authority	Solar PV	60	Kern	10	2025
Valley Clean Energy Alliance	Solar PV	108	Kern	15	2024
Total MW		2,896			

Table 13: New California Renewables Projects Contracted by CCAs with COD in 2024–2025
Data Source: CCAs' Draft RPS Procurement Plans (July 2024), CCAs' Annual RPS Compliance Reports (August 2024)

The CCAs also contracted with new renewable projects with commercial online dates further into the future and located outside of California. The table below lists additional in-state renewables contracts with commercial online dates in 2026 – 2027. Of the contracts listed, most are for new solar PV resources in addition to wind and geothermal.

Table 14: New California Renewables Projects Contracted by CCAs with COD in 2026-2027					
CCA	**Technology**	**Capacity (MW)**	**County Location**	**Contract Term (Years)**	**COD**
CleanPowerSF	Solar PV	75	Alameda	25	2026
CleanPowerSF	Wind	147	Merced	20	2026
Clean Power Alliance of Southern California	Geothermal	100	Sonoma	10	2027
Central Coast Community Energy	Solar + Storage	20	Tulare	15	2026
Central Coast Community Energy	Solar + Storage	70	Kern	10	2026
East Bay Community Energy	Solar PV	37	Merced	20	2027
East Bay Community Energy	Solar PV	100	Imperial	15	2027
Orange County Power Authority	Solar PV	90	Riverside	22	2027
San Diego Community Power	Solar PV	160	San Bernardino	20	2026
San Diego Community Power	Solar PV	90	San Diego	20	2026
San Diego Community Power	Solar PV	440	Kern	15	2027
San Jose Clean Energy	Solar PV	37	Merced	20	2027
San Jose Clean Energy	Solar PV	105	Kern	15	2026
Silicon Valley Clean Energy	Solar PV	120	Riverside	15	2027
Silicon Valley Clean Energy	Solar PV	20	Tulare	15	2027
Valley Clean Energy Alliance	Solar PV	26	Yolo	20	2026
Total MW		**1,637**			

Table 14: New California Renewables Projects Contracted by CCAs with COD in 2026-2027
Data Source: CCAs' RPS Draft Procurement Plans (July 2024), CCAs' Annual RPS Compliance Reports (August 2024)

Table 15 lists the CCAs' out-of-state contracts for new renewables projects.

Table 15: New Out-of-State Renewables Projects Contracted by CCAs with COD 2024–2027					
CCA	**Technology**	**Capacity (MW)**	**County Location**	**Contract Term (Years)**	**COD**
Central Coast Community Energy	Solar PV	150	La Paz, AZ	10	2025
Central Coast Community Energy	Wind	205	Lincoln, Torrance, San Miguel, NM	15	2026
Central Coast Community Energy	Geothermal	22	Pershing, NV	20	2024
Clean Power Alliance of Southern	Wind	575	Torrance, NM	15	2026

Table 15: New Out-of-State Renewables Projects Contracted by CCAs with COD 2024–2027					
CCA	**Technology**	**Capacity (MW)**	**County Location**	**Contract Term (Years)**	**COD**
California					
East Bay Community Energy	Wind	250	Lincoln, NM	15	2026
East Bay Community Energy	Solar PV	42.5	Maricopa, AZ	20	2026
Peninsula Clean Energy	Geothermal	21	NV[49]	20	2026
Peninsula Clean Energy	Wind	220	Lincoln, NM	15	2026
Pioneer Community Energy	Solar PV	60	Clark, NV	20	2024
San Diego Community Power	Solar PV	35	Clark, NV	20	2025
San Diego Community Power	Solar PV	150	Torrance, NM	15	2027
San Diego Community Power	Solar PV	400	Clark, NV	20	2027
San Jose Clean Energy	Geothermal	25	Clark, NV	20	2026
San Jose Clean Energy	Solar PV	65	Clark, NV	20	2024
San Jose Clean Energy	Solar PV	42.5	Maricopa, AZ	20	2026
Silicon Valley Clean Energy	Wind	100	Lincoln, Torrance, San Miguel, NM	15	2026
Silicon Valley Clean Energy	Solar PV	50	La Paz, AZ	10	2025
Sonoma Clean Power Authority	Wind	100	Torrance, NM	15	2026
Total MW		**2,513**			

Table 15: New Out-of-State Renewables Projects Contracted by CCAs with COD 2024–2026
Data Source: CCAs' RPS Draft Procurement Plans (July 2024), CCAs' Annual RPS Compliance Reports (August 2024)

Electric Service Providers (ESPs)

Historically, most ESPs exclusively contracted with renewable energy facilities that had achieved commercial operation at the time of contract execution and preferred to procure short-term (1-3 year) contracts. This is no longer the case of ESP procurement. Since 2020, seven ESPs have executed long-term contracts with new utility-scale renewable resources to meet the 65 percent long-term contracting requirement.

Table 16 shows the new long-term contracts executed by ESPs that have not yet reached their commercial operation dates.

49 Various counties in Nevada.

Table 16: New Long-term Renewables Projects with ESP Contracts					
ESP	**Technology**	**Capacity (MW)**	**County Location**	**Contract Term (Years)**	**COD**
Calpine Energy Solutions	Solar PV	40	Kern	10	2024
Calpine Energy Solutions	Solar PV	44	Riverside	10	2024
Direct Energy Business	Solar PV	70	Riverside	10	2024
Shell Energy North America	Solar PV	414	Cochise (AZ)	15	2025
Shell Energy North America	Solar PV	100	La Paz County (AZ)	10	2024
The Regents of the University of California	Solar PV	20	Kern	15	2025
The Regents of the University of California	Solar PV	45	Kern	15	2025
Total MW		**733**			

Table 16: New Long-term Renewables Projects with ESP Contracts
Data Source: ESPs' Draft RPS Procurement Plans (July 2024) and ESPs' Annual RPS Compliance Reports (August 2024)

Projects in Disadvantaged Communities

SB 350 directs the CPUC to consider within its programs and policymaking environmental and economic benefits for disadvantaged communities (DACs). DACs are the areas that suffer the most from a combination of economic, health, and environmental burdens.[50] These burdens include poverty, high unemployment, air and water pollution, and the presence of hazardous wastes as well as high incidence of asthma and heart disease.

The CPUC has implemented a number of clean energy initiatives for DACs and low-income customers. These initiatives include the Disadvantaged Communities Advisory Group (DACAG)[51], the Electric Vehicle

50 *See* CalEPA's website for more information on the DAC definition: https://oehha.ca.gov/calenviroscreen/sb535.

51 The DACAG is an 11-member advisory group created by SB 350 that advises CEC and the CPUC on how to implement policies and programs to be more effective on behalf of disadvantaged communities and in the achievement of the State's clean energy and pollution reduction goals. For more information, see https://www.energy.ca.gov/about/campaigns/equity-and-diversity/disadvantaged-communities-advisory-group-dacag.

Charging Infrastructure programs[52], the Green Tariff Shared Renewables (GTSR) Program[53], and the Disadvantaged Communities Green Tariff (DAC-GT) Program.[54] The CPUC is working to further meet the goals of SB 350 by continuing to consider the way it facilitates the locations of clean energy technologies to benefit overburdened communities.

Prioritizing renewable energy projects in DACs can enhance equity in the transition to a clean energy economy and broaden access to renewable energy benefits. Renewable energy projects offer many direct and indirect benefits to the community a project resides in. For example, property taxes paid by renewable energy developers are a direct benefit to the local community, resulting in significant public funding for the community's public school system, transportation services, low-income assistance, and public safety. Renewable facilities also offer increased job creation and infrastructure upgrades within the community. Indirect benefits of renewable facilities include increased local spending from facility employees and increased public health outcomes associated with low-emitting renewables.

In alignment with the direction of SB 350, the RPS Program reviews renewable facility locations relative to DACs to ensure that these direct and indirect benefits alleviate the disproportionate burdens these communities face. The CPUC's Power Purchase Agreement (PPA) review process includes a renewable facility location analysis relative to DACs using the CalEnviroScreen tool if the facility is located in California.[55] If the facility is located outside of California, the Climate and Economic Justice Screening Tool (CEJST)[56] can be used to identify DACs that are marginalized by underinvestment and overburdened by pollution.[57]

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52 The CPUC's Transportation Electrification program applies its expertise in electric rate design, electric system infrastructure deployment, grid management, and safety to support ZEV deployment, with special attention to deployment in DACs, pursuant to SB 350. For more information on these programs, see https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/transportation-electrification.

53 Enacted by SB 43 (Wolk, Chapter 413, Statues of 2013), the GTSR Program aims to (1) expand access "to all eligible renewable energy resources to all ratepayers who are currently unable to access the benefits of onsite generation," and (2) "create a mechanism whereby institutional customers…commercial customers and groups of individuals…can meet their needs with electrical generation from eligible renewable energy resources.". For more information on the GTSR Program, see https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates/green-tariff-shared-renewables-program.

54 The Disadvantaged Communities Green Tariff (DAC-GT) provides utility scale clean energy at a 20% bill discount for income-qualified, residential customers in DACs who may be unable to install solar on their roof. For more information, see https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/customer-generation/solar-in-disadvantaged-communities/the-disadvantaged-communities-green-tariff-dac-gt-program#:~:text=The%20Disadvantaged%20Communities%20Green%20Tariff%20%28DAC-GT%29%20provides%20utility,DAC-GT%20program%20should%20visit%20each%20Program%20Administrator%E2%80%99s%20website%3A.

55 The California Environmental Protection Agency's Office of Environmental Health Hazard Assessment (OEHHA) created CalEnviroScreen through a public process in order to help the state identify disadvantaged communities, and the tool "uses environmental, health, and socioeconomic information to produce scores for every census tract in the state." (https://oehha.ca.gov/calenviroscreen/.)

56 The CPUC acknowledges that there are rural regions with economic and environmental challenges that are not captured in CEJST and CalEnviroScreen.

57 The Justice40 Initiative was implemented by the Federal government and aims for 40 percent of the overall benefits of certain Federal climate, clean energy, affordable and sustainable housing, and other investments flow to disadvantaged communities.

The RPS Program also includes avenues for retail sellers to report on renewable energy procurement in DACs, beginning with annual RPS Procurement Plans. Pursuant to Public Utility Code § 399.14(b), the CPUC receives and reviews RPS Procurement Plans from all retail sellers. This annual process requires that each retail seller include their bid evaluation criteria and methodology for how bids from competitive RPS solicitations will be selected, also known as the Least-Cost Best-Fit (LCBF) evaluation. In particular, the CPUC directs retail sellers to describe how their solicitations and procurement decisions give preference to renewables located in specific communities[58] and how their methodologies address state policies related to equity, the environment, and economic development. While the CPUC has not specified how retail sellers should incorporate environmental and economic benefits to DACs, the CPUC has reviewed and approved IOUs' LCBF methodologies that evaluate project impacts on DACs.

Further, the CPUC has directed retail sellers to include descriptions of solicitations and procurement preferences within RPS Procurement Plans. Most recently, in their 2024 Draft RPS Procurement Plans[59], retail sellers described how they consider additional qualitative criteria to determine if projects are a fit for their needs and existing portfolios. Many retail sellers also described how they consider affordability, local benefits, and the impacts on DACs for new-build renewables. Some retail sellers even noted a preference for projects located in DACs.

The table below summarizes the degree to which retail sellers consider DACs in their solicitation evaluations. Three out of the three IOUs, two out three SMJUs, 20 out of 24 CCAs, and nine out of 11 ESPs described considerations for DACs within their Draft 2024 RPS Procurement Plans.

Table 17: DAC Considerations in LCBF Methodologies

Retail Seller Name	Retail Seller Type	Consideration
3 Phases Renewables (3PR)	ESP	3PR notes that when two suppliers present comparable pricing, 3PR would be inclined to select the supplier that is sourcing from projects located in DACs.
Apple Valley Choice Energy (AVCE)	CCA	AVCE will consider the air pollution impacts and benefits to DACs, including projected new jobs from the adjacent community, projected direct and indirect economic benefits to the local economy, and emissions reduction.
Ava Community Energy Authority (AVA - formerly EBCE)	CCA	AVA notes that it focuses on project location and potential economic and environmental benefits to communities in Alameda County with a "focus on disadvantaged communities".
Bear Valley Electric Service (BVES)	SMJU	As part of its decision-making process, BVES says it considers a potential project's impact on DACs and gives preference to projects that provide environmental and economic benefits to DACs.
BP Energy Retail (BPERC-	ESP	Among other qualitative attributes considered during project selection,

58 *See* Public Utilities Code Section 399.13(a)(8).
59 *See* Section 10 of Draft 2020 RPS Plans for CCAs for more information on their bid selection methodologies.

Table 17: DAC Considerations in LCBF Methodologies		
Retail Seller Name	**Retail Seller Type**	**Consideration**
formerly EDF)		BPERC says it considers the underlying resource's location, with a preference for resources sited in DACs. BPERC also says that among offers from projects under development, BPERC would give explicit preference for projects under development in DACs.
Brookfield Renewable Energy Marketing (BREMUS)	ESP	Among other qualitative attributes considered during project selection, BREMUS says it considers the underlying resource's location, with a preference for resources sited in DACs. BREMUS also says that among offers from projects under development, BREMUS would give explicit preference for projects under development in DACs.
Calpine Energy Solutions (CES)	ESP	CES notes that it gives preference to resources located in DACs when all selection criteria converge on equal.
Calpine Power America (CPOA)	ESP	As part of its decision-making process, CPOA says it considers a potential project's impact on DACs.
Clean Energy Alliance (CEA- formerly SEA)	CCA	Considers the air quality and economic impacts of a project on disadvantaged communities as part of its evaluation criteria.
Central Coast Community Energy (3CE)	CCA	3CE notes it will implement its Project Selection Criteria in upcoming solicitations to highlight RPS projects in DACs, preferring capacity contracts from generators or energy storage projects that do not have emissions impacts on DACs.
Clean Power Alliance of Southern California (CPA)	CCA	CPA notes that the consideration of benefits to DACs is one of six evaluation criteria utilized in its project selection process. CPA's solicitation process demonstrates a preference for projects that are located within DACs and that can demonstrate that they provide those communities with workforce development opportunities and target hiring of DAC residents.
CleanPowerSF (CPSF)	CCA	No mention of DACs in CPSF’s LCBF methodology, but CPSF mentions a preference for local resources from nine bay area counties in alignment with San Francisco’s environmental justice policy.
Commercial Energy of Montana (COMCA)	ESP	COMCA's bid evaluation process demonstrates that the ESP seeks projects that are located within DACs and that provide support for DACs.
Desert Community Energy (DCE)	CCA	Considers the impact of a project on disadvantaged communities as part of its evaluation criteria.
NRG (formerly Direct Energy Business - DEB)	ESP	As part of its decision-making process, NRG says it considers a potential project's impact on DACs and gives preference to projects that provide environmental and economic benefits to DACs.
Energy for Palmdale's Independent Choice (EPIC - formerly CPALM)	CCA	Requires that projects located in DACs provide insight into the emissions, workforce, and economic impacts that could be imposed on the surrounding DAC.
King City Community Power (KCCP)	CCA	Considers the air quality and economic impacts of a project on DACs as part of its evaluation criteria.
Lancaster Choice Energy	CCA	Requires that projects located in DACs provide insight into the emissions,

Table 17: DAC Considerations in LCBF Methodologies		
Retail Seller Name	**Retail Seller Type**	**Consideration**
(LCE)		workforce, and economic impacts that could be imposed on the surrounding DAC.
Liberty Utilities CalPeco (LIBU)	SMJU	Does not mention specific consideration of projects located in DACs as part of it LCBF methodology.
Marin Clean Energy (MCE)	CCA	Evaluates offers according to their potential economic benefits to nearby communities with high levels of poverty and unemployment.
Orange County Power Authority (OCPA)	CCA	Considers the air quality and economic impacts of a project on DACs as part of its evaluation criteria.
Pacific Gas and Electric Company (PG&E)	IOU	PG&E may use a project's impact on DACs to determine its status for shortlisting and/or contract execution.
PacifiCorp (PCORP)	SMJU	PCORP notes that to the extent that California-based facilities participate in future solicitations, that it will consider and provide preference for facilities located in DACs.
Peninsula Clean Energy (PCE)	CCA	Evaluates whether projects located in DACs can demonstrate community benefits, as well as workforce and community development benefits within the nearby DAC.
Pilot Power Group (PPG)	ESP	Does not mention specific consideration of projects located in DACs as part of it LCBF methodology.
Pioneer Community Energy (PION)	CCA	Considers the air quality and economic impacts of a project on DACs as part of its evaluation criteria.
Pomona Choice Energy (POCE - formerly CPOM)	CCA	Considers the air quality and economic impacts of a project on DACs as part of its evaluation criteria.
Rancho Mirage Energy Authority (RMEA)	CCA	Considers the air quality and economic impacts of a project on DACs as part of its evaluation criteria.
Redwood Coast Energy Authority (RCEA)	CCA	RCEA says it recognizes the importance of considering DACs in its procurement processes.
San Diego Community Power (SDCP)	CCA	Considers the air quality, workforce, and economic impacts of a project on DACs as part of its evaluation criteria.
San Diego Gas & Electric (SDG&E)	IOU	Uses a project's impact on DACs as one factor to determine its status for shortlisting and/or contract execution.
San Jacinto Power (SJP)	CCA	Considers the air quality, workforce, and economic impacts of a project on DACs as part of its evaluation criteria.
San Jose Clean Energy (SJCE)	CCA	SJCE does not mention consideration of disadvantaged communities in its solicitation evaluation criteria.
Santa Barbara Clean Energy (SBCE - formerly CSB)	CCA	Considers the air quality and economic impacts of a project on disadvantaged communities as part of its evaluation criteria.
Shell Energy North America (SENA)	ESP	Gives consideration to projects located in DACs, though it does not have a specific value for such a consideration.

Table 17: DAC Considerations in LCBF Methodologies		
Retail Seller Name	**Retail Seller Type**	**Consideration**
Silicon Valley Clean Energy (SVCE)	CCA	When selecting green power projects, SVCE considers whether proposed facilities are located within DACs or otherwise contribute to DAC economic development.
Sonoma Clean Power Authority (SCPA)	CCA	SCPA does not mention consideration of disadvantaged communities in its LCBF evaluation criteria.
Southern California Edison (SCE)	IOU	Uses a project's impact on DACs as one factor to determine its status for shortlisting and/or contract execution.
UC Regents (UCR)	ESP	Does not mention specific consideration of projects located in DACs as part of it LCBF methodology.
Valley Clean Energy Alliance (VCEA)	CCA	There is no mention of consideration for DACs in the project selection criteria. VCEA says will consider equity and impacts on DACs in future solicitations.

Table 17: DAC Considerations in LCBF Methodologies
Source: 2024 Draft RPS Procurement Plans

The following map uses data from the 2024 Draft RPS Procurement Plans to show where new renewable projects contracted by IOUs, SMJUs, CCAs, and ESPs are being built relative to DAC census tracts, as informed by CEJST Disadvantaged Community results.

Figure 9: New RPS Projects Contracted by LSEs (CODs in 2024-2028)[60]

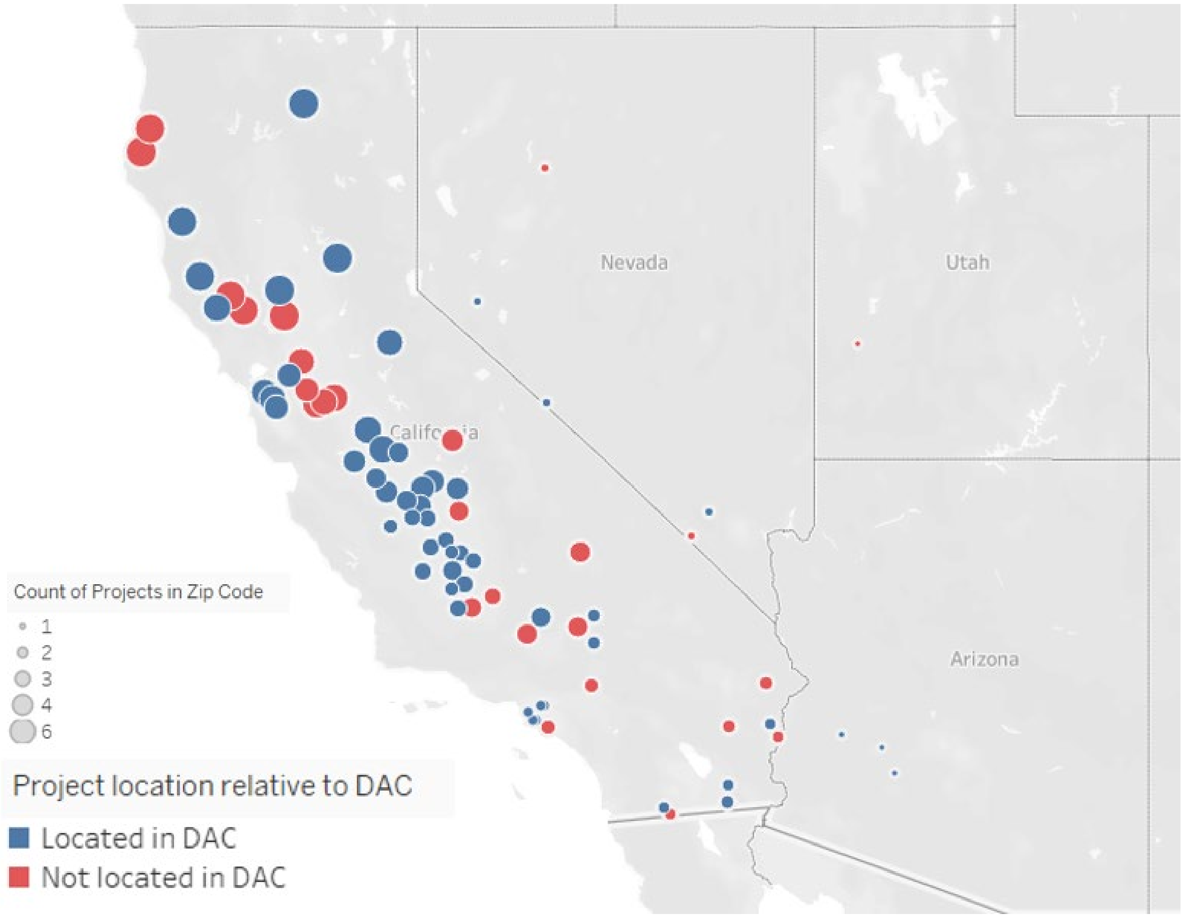


Figure 9: New RPS Projects Contracted by LSEs
Data Source: Project Development Status Update data from the 2024 Draft Procurement Plans

The following tables summarize the total number of new renewable projects contracted in DACs by LSE type, as well as a breakdown by resource type.

60 Excludes projects with "Multiple" or "Various" locations. 118 of the projects included on this map are in California, while 45 projects are out-of-state.

Table 18: New RPS Projects in DACs with CODs in 2024-2028[61]		
LSE Type	**Projects in DACs**	**New Projects**
CCAs	60	93
ESPs	4	8
IOUs	35	49
SMJUs	0	0
Total[62]	**99**	**150**

Table 18: New RPS Projects in DACs
Data Source: Project Development Status Update data from the 2024 Draft Procurement Plans

Table 19: New RPS Projects in DACs by Resource Type with CODs in 2024-2028[63]			
Resource Type	**Projects in DACs**	**(%) Projects in DACs**	**New Projects**
Biomass	6	66%	9
Biogas	0	0%	1
Digester Gas	1	100%	1
Geothermal	10	43%	23
Solar - Battery Storage	24	57%	42
Solar PV	54	77%	70
Solar Thermal - No Storage	1	100%	1
Wind	3	100%	3
Total	**99**	**66%**	**150**

Table 19: New RPS Projects in DACs by Resource Type
Data Source: Project Development Status Update data from the 2024 Draft Procurement Plans

Progress in Long-Term Contracting

A key aspect of meeting RPS requirements is meeting the long-term contract procurement requirement which requires all retail sellers to procure 65 percent of their RPS portfolios through long-term contracts[64]

61 Excludes projects with "Multiple" or "Various" locations.
62 Total number of RPS Projects does not include those categorized as Multiple or Various locations.
63 Excludes projects with "Multiple" or "Various" locations, as well as three Pre-Construction projects that did not have a technology type listed.
64 Long-term contracts are defined as contracts with a term of ten or more years.

beginning in the 2021–2024 compliance period.[65] This section uses RPS compliance report data to identify the status and progress of all retail sellers in meeting the long-term contract procurement requirement. Progress is measured as a percentage of a retail seller's total long-term contract procurement requirement, based on their Procurement Quantity Requirement (PQR). See the Compliance and Enforcement section of this report for the status and progress regarding overall RPS requirements.

Investor-Owned Utilities: Each of California's three IOUs is expected to exceed its long-term contract procurement requirement for the 2021-2024 compliance period. Most of the IOUs' RPS procurement is met from long-term contracts; each IOU surpassed their long-term contract procurement requirement by over 50 percent.

Small and Multi-Jurisdictional Utilities: One of the three SMJUs (PacifiCorp) is contracted to meet their long-term contract procurement requirements for the 2021-2024 compliance period. BVES and Liberty currently forecast a 1 percent shortfall in procuring long-term Renewable Energy Credits (RECs) in 2024 to meet their long-term contract procurement requirement.

Community Choice Aggregators: As reflected in Table 20, 22 out of 25 of the CCAs are projected to meet their long-term contract procurement requirements for the 2021-2024 compliance period. Since last year's compliance reporting, three CCAs have fallen below their long-term contract procurement requirements. Desert Community Energy, Lancaster Choice Energy and Clean Power Authority each forecast satisfying more than 90 percent of their long-term contract procurement requirement, but there is little time left in the 2021-2024 compliance period to procure the remainder.

Table 20: Percentage of CCA 65% Long-Term Contract Procurement Requirements

CCA Name	2017-2020 Compliance Period	2021-2024 Compliance Period
Apple Valley Choice Energy	100%	100%
Ava Community Energy	100%	100%
Central Coast Community Energy	100%	100%
City of Baldwin Park66	100%	N/A
Clean Energy Alliance	N/A	100%
Clean Power Alliance	100%	94%
CleanPowerSF	100%	100%
Desert Community Energy	100%	93%
Energy for Palmdale's Independent Choice	N/A	100%
King City Community Power	100%	100%

65 See D.17-06-026 "Decision Revising Compliance Requirements for the California Renewables Portfolio Standard in Accordance with Senate Bill 350," for more information.
66 City of Baldwin Park deregistered as a CCA and is no longer serving load.

Table 20: Percentage of CCA 65% Long-Term Contract Procurement Requirements		
CCA Name	**2017-2020 Compliance Period**	**2021-2024 Compliance Period**
Lancaster Choice Energy	100%	99%
Marin Clean Energy	100%	100%
Orange County Power Authority	N/A	100%
Peninsula Clean Energy	100%	100%
Pico Rivera Innovative Municipal Energy	100%	100%
Pioneer Community Energy	100%	100%
Pomona Choice Energy	100%	100%
Rancho Mirage Energy Authority	100%	100%
Redwood Coast Energy Authority	100%	100%
San Diego Community Power	N/A	100%
San Jacinto Power	100%	100%
San Jose Clean Energy	100%	100%
Santa Barbara Clean Energy	N/A	100%
Silicon Valley Clean Energy	100%	100%
Solana Energy Alliance[67]	100%	N/A
Sonoma Clean Power Authority	100%	100%
Valley Clean Energy	100%	100%
Western Community Energy[68]	100%	N/A

Table 20: Percentage of CCA 65% Long-Term Contract Procurement Requirements
Data Source: CCAs' Annual RPS Compliance Reports (August 2024)

Electric Service Providers: Four out of ten electric service providers' compliance reports forecast them falling short of their long-term contract procurement requirement for the 2021-2024 compliance period.

Three ESPs stopped serving load in the 2021-2024 compliance period, and there is one new market entrant, Brookfield Renewable Energy Marketing, however they have yet to serve load.

Table 21: Percentage of ESP 65% Long-Term Contract Procurement Requirements		
ESP Name	**2017-2020 Compliance Period**	**2021-2024 Compliance Period**
3 Phases Renewables	100%	100%

67 Solana Energy Alliance deregistered as a CCA and is no longer serving load.
68 Western Community Energy deregistered as a CCA and is no longer serving load.

Table 21: Percentage of ESP 65% Long-Term Contract Procurement Requirements		
ESP Name	**2017-2020 Compliance Period**	**2021-2024 Compliance Period**
American PowerNet[69]	100%	N/A
BP Energy Retail	100%	83%
Brookfield Renewable Energy Marketing U.S.[70]	N/A	N/A
Calpine Energy Solutions	100%	67%
Calpine Power America	100%	100%
Commercial Energy of California	100%	100%
Constellation NewEnergy	100%	97%
NRG (Direct Energy Business)	100%	100%
Just Energy Solutions[71]	100%	N/A
Pilot Power Group	100%	100%
Shell Energy North America	100%	81%
Tiger Natural Gas72	100%	N/A
UC Regents	100%	100%

Table 21: Percentage of ESP 65% Long-Term Contract Procurement Requirements
Data Source: ESPs' Annual RPS Compliance Reports (August 2024)

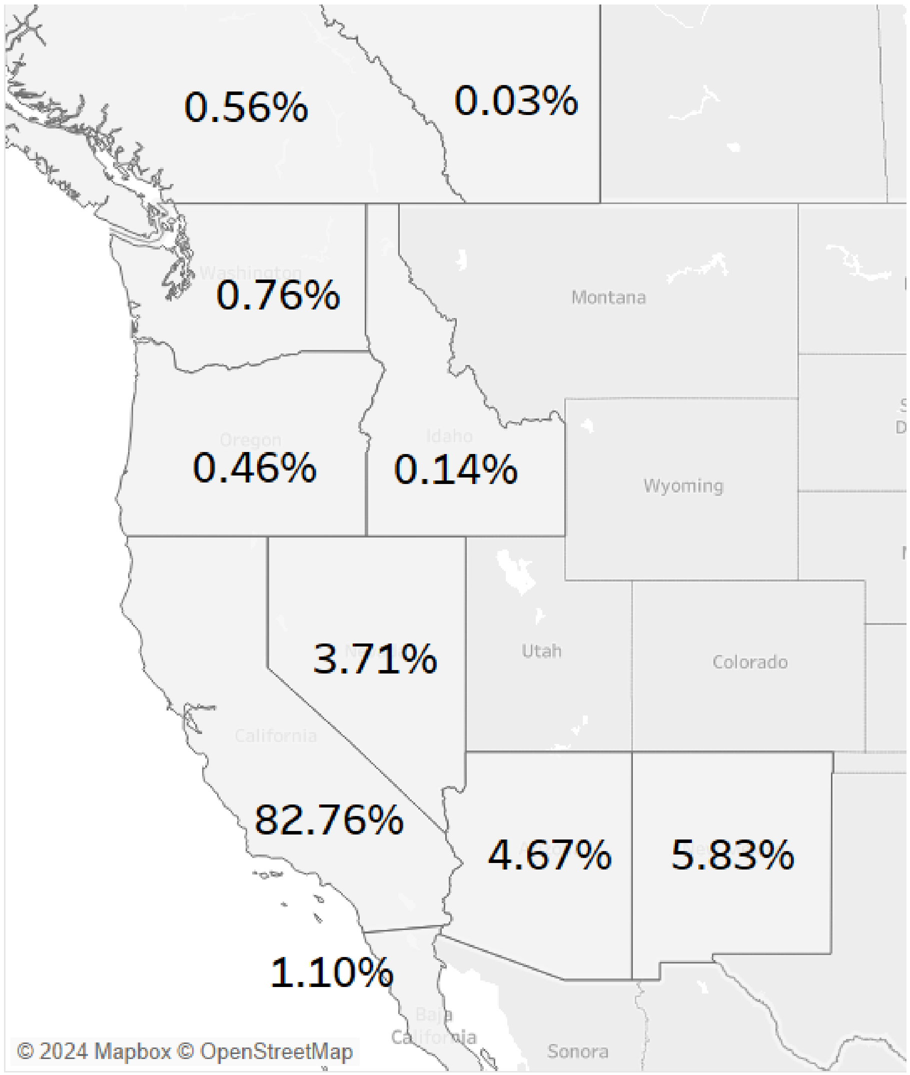
Project Location and Mapping

The RPS Portfolio Balance Requirement (PBR) requires retail sellers to now procure 75 percent of their RPS requirements from Portfolio Content Category (PCC) 1 RECs, which are defined as RECs procured with associated generation from generation sources with a first point of interconnection within a California balancing area, scheduled into the California grid without substituting energy from other sources, or be dynamically scheduled to a California balancing authority.[73] The PBR has fostered development of California renewable energy resources; as depicted in Figure 10, it is expected that 82 percent of the PCC 1 RECs in the compliance period 2021-2024 are generated within California, with the remainder generated throughout the Western interconnect.[74] A variety of factors can contribute to developers siting projects

69 American PowerNet plans to not serve load in the 2021-2024 compliance period.
70 Brookfield Renewable Energy Marketing U.S. (BREMUS) is a new ESP that registered with the CPUC as an effective May 3, 2022 and is not yet serving load.
71 Just Energy Solutions plans to not serve load in the 2021-2024 compliance period.
72 Tiger Natural Gas plans to not serve load in the 2021-2024 compliance period.
73 See D.12-06-038: Decision Setting Compliance Rules for the Renewables Portfolio Standard Program and D.11-12-052: Decision Implementing RPS Portfolio Content Categories
74 PCC determination is made during the RPS compliance determination process that takes place after the end of the compliance period.

outside of California, including resource diversity and availability, permitting considerations, available transmission capacity, and labor costs.

Figure 10: Locations of PCC 1 RECs Forecasted to be Retired in Compliance Period 2021-2024



Source: California Public Utilities Commission 2023 RPS Compliance Reports

Figure 10: Locations of PCC 1 RECs Forecasted to be Retired in Compliance Period 2021-2024

Figure 11 shows the distribution of the currently expected Compliance Period 2021-2024 generation from renewable resources within California by county; buildout in Kern County's strong sun and wind resources contribute to 27 percent of the state's renewable energy generation. Riverside, Imperial, and Sonoma counties also show strong generation profiles. Resource availability, ease of local permitting, land value, terrain and accessibility, and transmission availability are factors contributing to site selection. According to their draft 2024 RPS procurement plans, retail sellers are beginning to notice negative effects of high concentrations of generation in single geographic regions, specifically an increase in the frequency of negative energy prices when generation is robust, and demand is low or moderate. Based on retail sellers' currently executed RPS contracts, Figure 12 shows that while the majority of the new projects and renewable capacity expected to come online in 2024-2028 will be located in California, there is a significant amount of expected capacity from outside of California.

Figure 11: Distribution of CA Renewable Energy Generation for Compliance Period 2021-2024

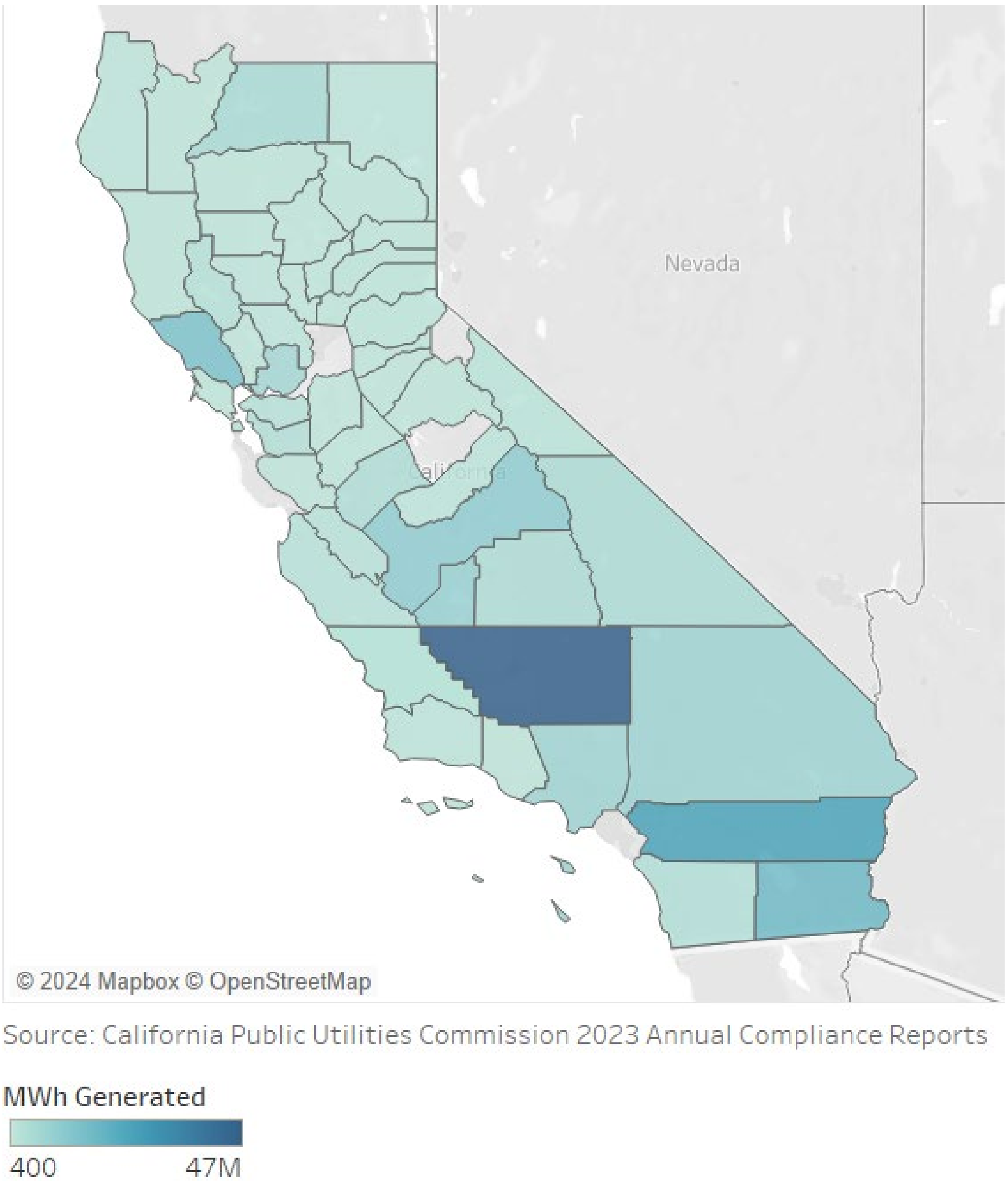


Figure 11: Distribution of CA Renewable Energy Generation for Compliance Period 2021-2024

Figure 12: New Renewable Projects by Total MW and State (CODs in 2024-2028)[75]

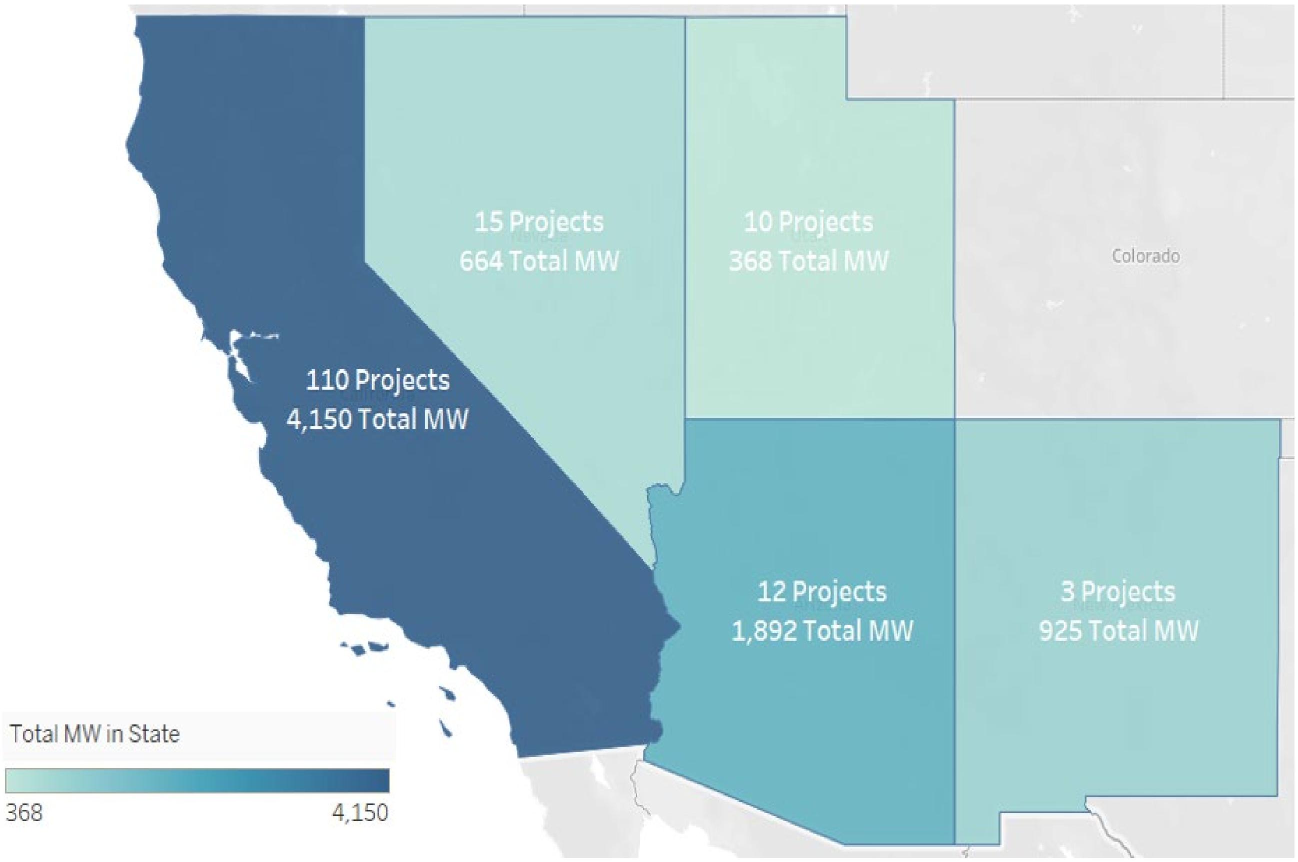


Figure 12: New Renewable Projects by Total MW and State (CODs in 2024-2028)
Data Source: Project Development Status Update data from the 2024 Draft Procurement Plans

75 Excludes projects with "Multiple" or "Various" locations.

2023 RPS Program Activities

This chapter identifies and discusses key 2023 and 2024 RPS program activities and accomplishments including implementation of legislation, procurement activities, and interagency planning and coordination. Appendix C includes a detailed list of RPS program activities.

New RPS Proceeding

On January 25, 2024, a new Order Instituting Rulemaking (OIR) (R.24-01-017)[76] was issued to continue implementation and administration of the California RPS program. As a successor docket to R.18-07-003, this proceeding provides a home for all the elements of the ongoing administration of the RPS program that require recognition or action in a formal Commission proceeding. R.24-01-017 includes many elements of the RPS program that are continuous, such as review and approval of RPS procurement plans and IOU RPS contracts; assessment of retail sellers' compliance with their RPS procurement obligations; review and revision of analytic tools that can improve the value of the RPS program and streamline its administration; and coordination across Commission proceedings and with other agencies. The proceeding also includes some elements of the program that are addressed only intermittently, such as incorporation of legislative changes to the RPS statute, potential enforcement action when a retail seller does not comply with its RPS procurement obligations, or possible further development of the RPS program. Finally, the proceeding includes the ongoing monitoring, reviewing and revising, as needed, of all RPS procurement methods and tariffs, such as IOU solicitations, the renewable auction mechanism (RAM), the Renewable Market Adjusting Tariff (ReMAT), and the Bioenergy Market Adjusting Tariff (BioMAT).

The Commission issued a Scoping Memo[77] for R.24-01-017 on May 9, 2024, to set forth the initial schedule and issues for consideration in the proceeding. According to the Scoping Memo, the issues to be determined or considered can be grouped into three overall areas: continuing and completing specific tasks from the previous RPS proceeding that were not completed; continuing the monitoring, reviewing, and improvement of the RPS program; and implementing new statutory requirements, if any. Specific issues that are scheduled to be addressed in 2024 and 2025 include: reviewing RPS procurement plans, considering IOU proposals to streamline short-term RPS transactions, clarifying RPS confidentiality rules, and coordination and alignment with the IRP proceeding and process.

76 See R.24-01-017 at https://apps.cpuc.ca.gov/apex/f?p=401:56::::RP,57,RIR:P5_PROCEEDING_SELECT:R2401017.
77 The full Scoping Memo can be found at https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=531247661.

Integrated Resource Planning and RPS Alignment

Since the adoption of SB 350 in 2015, the CPUC has been identifying opportunities for coordination between the RPS program and the IRP program.[78] The CPUC adopted an IRP framework in 2018 to coordinate and refine long-term planning requirements for CPUC-jurisdictional retail sellers, which includes planning for increasing renewables.[79] Activities in the IRP proceeding are complementary to RPS procurement activities and resource planning for the electric sector.

The CPUC is working to align the IRP and RPS proceedings further to coordinate planning efforts and address the overlap in reporting and procurement requirements. Since 2019, retail sellers' annual RPS procurement plans have been required to show how they align or conform with their respective IRPs. In 2023, the IOUs were permitted to use capacity values generated in the IRP proceeding for the evaluation of renewable project bids in their RPS solicitations.[80] This will serve to remove analytical inconsistencies and redundant processes in the IRP and RPS proceedings, thereby increasing resource planning efficiency and sending more consistent signals to the renewables market regarding the ability of resources to contribute to system reliability. Next steps in IRP and RPS alignment include further coordinating due dates, filings, planning materials, and reporting requirements in order to mitigate administrative burden as well as considering the integration of IRP preferred system plans with the RPS procurement plans. These alignment activities are scheduled to be undertaken in the RPS proceeding in 2025.[81]

Voluntary Allocation and Market Offer Process for RPS Portfolio Optimization

On May 24, 2021, the CPUC issued Decision (D.) 21-05-030 to authorize new Voluntary Allocation, Market Offer, and Request for Information (RFI) processes for IOU RPS contracts subject to the Power Charge Indifference Adjustment (PCIA). The adopted Voluntary Allocation and Market Offer (VAMO) mechanism is an authorized process for PG&E, SCE, and SDG&E to allocate a "slice" of their entire PCIA-eligible RPS portfolios to eligible retail sellers (such as CCAs, ESPs, and the IOUs themselves) in proportion to their vintaged, forecasted annual load share. The purpose of the VAMO and RFI processes is to reduce excess and uneconomic resources in the IOUs' PCIA-eligible RPS portfolios through voluntary and market-based solutions.

78 For more information on the IRP proceeding (R.20-05-0023), visit https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning.

79 *See* D.18-02-018.

80 *See* D.23-08-003.

81 *See* the Assigned Commissioner's Scoping Memo and Ruling, dated May 9, 2024, issued in R.24-01-017. The full Scoping Memo can be found at https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=531247661.

Voluntary Allocations

As the initial step in the VAMO process, some eligible retail sellers elected to take Voluntary Allocations of their share, or "slice", of an IOU's PCIA-eligible RPS portfolio. Voluntary Allocations featured standard offer contracts with fixed prices that are based on the applicable year's market price benchmark. Eligible retail sellers were permitted to elect a short-term allocation, a long-term allocation, or were permitted to decline all or a portion of their allocation of RPS resources. Although Voluntary Allocations may be held no more than once in an RPS compliance period, a newly formed retail seller may request an initial Voluntary Allocation if its launch does not coincide with a regular VAMO cycle.

The IOUs completed their initial Voluntary Allocation contracting on July 29, 2022. While the IOUs elected to receive 100 percent of their respective shares of Voluntary Allocations, the results for the non-IOU retail sellers' Voluntary Allocations were mixed across the three IOU service territories. Twenty-four of the eligible 35 non-IOU retail sellers elected to receive 45.7 percent of the total PCIA-eligible RPS resource volumes available to them for Voluntary Allocation through a mix of short- and long-term allocations.[82] The CPUC approved the Voluntary Allocations on November 3, 2022.

Market Offers

After the Voluntary Allocations, the IOUs solicited Market Offers for all remaining PCIA-eligible RPS resources. Unlike Voluntary Allocations, IOUs were permitted to propose more than one Market Offer in an RPS compliance period. Market Offers are closely based on previously approved IOU REC sales solicitations in the CPUC's RPS proceeding in terms of solicitation processes, contract formats, and fixed pricing. The IOUs each held two Market Offer solicitations in 2023. In January, the IOUs conducted Short-Term Market Offer solicitations, and the resulting executed contracts were approved by the CPUC in May 2023. In March and April of 2023, the IOUs conducted Long-Term Market Offer solicitations for volumes that remained after Voluntary Allocations from long-term contracts in their PCIA-eligible RPS portfolios. The IOUs were required to offer 35 percent of their respective remaining volume as long-term product, and 65 percent of their respective remaining volume as either long or short-term product. The CPUC reviewed the Market Offer solicitation and contracts via the advice letter and resolution process. Short-term Market Offer contracts were approved in April 2023[83] and Long-term Market Offer contracts were approved in November and December 2023.[84]

As shown below in Table 22, the IOUs executed 17 contracts for an expected total of 46.2 million MWh.

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82 Calculated as the statewide weighted total of non-IOU retail seller Voluntary Allocation Elections.

83 Short-term Market Offer contracts approved via Advice Letters 4986-E, 6894-E, and 4188-E for Southern California Edison, Pacific Gas and Electric, and San Diego Gas & Electric, respectively.

84 Long-Term Market Offer contracts approved by Resolution E-5291, E-5295, and E-5305 for Southern California Edison, Pacific Gas and Electric, and San Diego Gas & Electric, respectively.

Table 22: Summary of IOU Market Offer Contracts of PCIA-Eligible RPS Resources in 2023		
Service Territory	**Quantity of Contracts**	**Estimated Total Quantity of Generation (MWh)**
Pacific Gas and Electric	13	28,432,387
Southern California Edison	4	15,533,297
San Diego Gas & Electric	4	1,034,617
Total	21	**46,429,625**

Table 22: Summary of IOU Market Offer Contracts of PCIA-Eligible RPS Resources in 2023
Data Source: CPUC 2023 VAMO 90-Day Reports

Requests for Information

D.21-05-030 additionally directed the three IOUs to issue at least two requests for information (RFI) for contract modifications and assignments. The IOUs each included RFIs in their 2021 and 2022 RPS Procurement Plans, each for the subsequent year. Although no contract amendments or assignments have yet been submitted for CPUC approval, two of the IOUs (PG&E and SDG&E) are currently engaging with counterparties for contract termination, assignment, or modification as a result of their 2023 RFI solicitations. As in their 2023 RPS Procurement Plans, none of the IOUs propose additional RFIs in their draft 2024 Procurement Plans.

Workshop and Report

Ninety days following conclusion of the market offer solicitations, the IOUs submitted reports (90-Day Report). In their 90-Day Reports, all three IOUs conclude that VAMO was a success with all or nearly all VAMO-eligible resources either allocated or sold. As a result, the IOUs anticipated having physical short RPS positions starting as early as 2023 but being able to meet RPS requirements using previous excess RPS procurement (or “banked” RECs). The IOUs jointly held a workshop on November 6, 2023, on VAMO effectiveness. After the workshop, each IOU was required to file an advice letter with their recommendation of whether or not to continue to conduct VAMO processes for subsequent RPS compliance periods. The CPUC received these advice letters on December 19, 2023, and approved the IOUs’ unanimous request not to conduct future VAMO processes.

Implementation of AB 843

Assembly Bill (AB) 843 (Aguiar-Curry, Chapter 234, Statues of 2021) authorizes CCAs to submit eligible bioenergy projects for cost recovery equivalent to that authorized for IOUs under the current BioMAT program. Under AB 843, CCAs are permitted to submit contracted projects for cost recovery purposes if unsubscribed capacity exists within the 250 MW BioMAT program capacity target. Approximately 50 MW is currently subscribed. In addition, AB 843 requires that every kilowatt-hour (kWh) of electricity purchased from a CCA bioenergy project count towards the CCA's RPS procurement requirements as well as the RPS procurement requirements of the electrical corporation where a CCA provides service.

On October 26, 2022, an Order Instituting Rulemaking (OIR) (R.22-10-010) was issued to implement AB 843.[85] The proceeding considered the ability of CCAs to use any available procurement capacity in the BioMAT program. On April 28, 2023, RPS staff conducted a public workshop to solicit input on several proposed BioMAT program changes from a wide range of stakeholders including IOUs, CCAs, the CPUC Public Advocates Office, numerous industry groups, local jurisdictions, environmental justice advocates, and local air quality regulators.

Parties discussed potential changes related to CCA and tariff structure and filing requirements, contract management processes, project queue design and management, Commission adoption and oversight of new prudent contract management standards for CCAs, as well as important issues pertaining to program cost and benefit allocation, tracking, and recovery. Parties were furthermore asked to consider how CCA participation in BioMAT may impact environmental and social justice communities.

On November 30, 2023, the CPUC adopted D.23-11-084 which sets rules to enable CCAs to participate in the BioMAT program, as authorized by AB 843. On January 29, 2024, the Joint CCAs submitted a Joint Tier 2 Advice Letter requesting Energy Division approval of a suite of BioMAT program implementation documents. The Joint CCAs include Central Coast Community Energy, Orange County Power Authority, Pioneer Community Energy, and Redwood Coast Energy.

On June 24, 2024, the four CCAs (Central Coast Community Energy, Orange County Power Authority, Pioneer Community Energy, and Redwood Coast Energy Authority) each submitted a Tier 3 Advice Letter requesting approval of Bioenergy Market Adjusting Tariff (BioMAT) Program 2024 and 2025 Forecasted Revenue Requirements Pursuant to D.23-11-084.

D.23-11-084 requires CCAs that elect to participate in the BioMAT program to consult with the IOUs and Accion Group - the IOUs current BioMAT program platform vendor - to open pre-designed CCA program portals within the new IOU/CCA web-based joint procurement management platform. By doing so, IOUs and CCAs are each able to inform project applicants in real time about available BioMAT program capacity within their respective project queues and to receive and timestamp Program Participation Requests (PPRs) such that contracting eligibility for procurement allocation can be effectively established. Currently, Central

85 AB 843 amended Public Utilities Code Section 399.20 to extend to CCAs within an IOU's service territory the existing renewable feed-in tariff (BioMAT) for qualifying bioenergy electric generation facilities. AB 843 authorizes a CCA to execute contracts for eligible bioenergy projects and submit those contracts for cost recovery pursuant to the BioMAT program, if open capacity exists within the 250 MW BioMAT program limit. AB 843 additionally requires that every kilowatt hour of electricity purchased from a qualifying bioenergy electric generation facility count toward both the CCA's RPS procurement requirements and the BioMAT project procurement requirements of the IOU whose service territory encompasses the CCA.

Coast Community Energy, Orange County Power Authority, Pioneer Community Energy, and Redwood Coast Energy Authority each have an active BioMAT website.

Additional Mandated RPS Procurement Activities

The IOUs are required to procure renewable energy through mandated programs to meet additional State policy goals. SMJUs, CCAs, and ESPs are not required to procure RPS resources through these mandated programs. However, bioenergy program costs are allocated to all IOU, CCA, and ESP customers.[86]

Feed-in Tariff Programs

California's Feed-in Tariff (FIT) program is a policy mechanism designed to accelerate investment in small, distributed renewable energy technologies. The goal of the FIT program is to offer long-term contracts and price certainty for financing renewable energy investments to aid in transforming these markets. The RPS program has two FIT programs:

- Renewable Market Adjusting Tariff (ReMAT)
- Bioenergy Market Adjusting Tariff (BioMAT)

Both programs have capacity procurement amounts established by the California Legislature, which are allocated to each IOU based on their proportionate share of statewide electric load served.

ReMAT

ReMAT[87] is a FIT program established by SB 32 (Negrete McLeod, Chapter 328, Statues of 2009) and SB 2 and commenced offering fixed-price standard contracts in 2013. Small RPS-eligible facilities generating up to 3 MW[88] can sell renewable electricity to utilities under ReMAT's standard terms and conditions for terms of 10 to 20 years. ReMAT features administratively set prices by product category with a time-of-delivery adjustment that matches the retail sellers RPS contracts. In June of 2024, the CPUC approved an annual ReMAT pricing update per the methodology adopted in D.20-10-005.[89]

Table 23 below provides an overview of the progress that each IOU has made toward their ReMAT capacity mandate[90] from the program's inception in 2013 to present. It should be noted that contracts

86 Per SB 859 (Chapter 368, Statues of 2016), all customers are required to support the BioRAM program through a non-bypassable charge as implemented in D.18-12-003; the BioMAT program implemented a similar non-bypassable charge in D.20-08-043 as part of program improvements.

87 The ReMAT program replaced California's original FIT program established by AB 1969 (Yee, Chapter 731, Statues of 2006) to expand the program and increase eligible project size from a maximum of 1.5 MW to 3 MW.

88 AB 1979 (Bigelow, Chapter 665, Statues of 2016) modified the program to increase the maximum project capacity to 4 MWs for conduit hydroelectric facilities, if they deliver no more than 3 MW.

89 See D.20-10-005 at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M348/K746/348746212.PDF.

90 PUC § 399.20 establishes a program capacity that LSEs must procure.

procured under the CPUC's original FIT program, prior to ReMAT's creation in 2013, count towards an IOU's procured total of their allocation of the mandated 493.6 MW capacity. The "ReMAT Remaining (MW)" column in Table 23 considers these previously procured contracts in determining the IOUs remaining ReMAT procurement amounts. The ReMAT program has approximately 206 MW of capacity left to procure.

Table 23: IOU ReMAT Procurement			
IOU	**Procurement Mandate[91]**	**ReMAT Contracted (MW)**	**ReMAT Remaining (MW)[92]**
PG&E	218.8	45.29	107.56
SCE	226	45.81	77.70
SDG&E	48.8	7.58	20.91
Total	**493.6**	**98.68**	**206.17**

Table 23: IOU ReMAT Procurement
Data Source: PG&E, SCE, and SDG&E ReMAT Program web pages (August 2024).

BioMAT

BioMAT is a FIT program established by SB 1122 (Rubio, Chapter 612, Statues of 2012), which set a 250 MW procurement program requirement for small-scale bioenergy projects.[93] The goal of the BioMAT program is to promote competition for entrants to the bioenergy market using a simplified procurement mechanism. BioMAT procurement is allocated to three discrete bioenergy categories: Biogas, Agriculture, and Sustainable Forest Management. The program was implemented in 2014[94] and uses a standard contract and a market-based mechanism to arrive at the offered program contract price. AB 843 authorized CCAs to participate in the BioMAT program and was implemented in 2024. See the above Implementation of AB 843 section for more information on AB 843.

Table 24 shows the BioMAT targets and capacity (MW) procured over the life of the program by the three IOUs.[95] As of September 2024, no BioMAT contracts have been executed by CCAs.

91 D.12-05-035 allocates a portion of a 750 MW program cap (PUC § 399.20) to each IOU. See http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/167679.pdf.
92 Remaining amount accounts for contracting done via the original FIT program as well as contracting via ReMAT.
93 AB 1923 (Wood, Chapter 663, Statues of 2016) increased eligible project size to 5 MW, and more recently AB 843 expanded the program to CCAs that wish to participate.
94 *See* D.14-12-081.
95 While several CCAs began offering BioMAT contracts in 2024, none have been executed to date.

Table 24: BioMAT Mandated Allocation by IOU					
BioMAT Category	**BioMAT MW Allocation**	**MW Contracted**	**MW Remaining**	**# of Contracts**	**Current Contract Price ($/MWh)**
Biogas	110	24.82	85.18	10	127.72
Dairy/Agriculture	90	27.82	62.18	21	187.72 (Dairy) 183.72 (Other Agriculture)
Sustainable Forest Management	50	32.48	17.52	14	199.72
Total	**250**	**85.12**	**164.88**	**45**	**-**

Table 24: BioMAT Mandated Allocation by IOU
Data Source: CPUC Database (September 2024).

BioMAT contracts were initially offered at $127.72/MWh. All contracts in the Biogas category have been executed at the program starting price of $127.72/MWh. All contracts in the Dairy/Agriculture category have been executed at $187.72/MWh. All contract executions in the Sustainable Forest Management category have occurred at a price of $199.72/MWh. The current price offerings are shown in Table 24.

BioMAT Technical Working Group on GHG Emissions

Pursuant to D.20-08-043, in April 2021 the CPUC established a technical working group of stakeholders to develop a project-specific lifecycle greenhouse gas (GHG) emissions reduction model to quantify the net emissions of the BioMAT program's project operations. The CPUC solicited participation from technical experts from parties, public agencies, academia, industry, national labs, and research institutions. The working group is utilizing a Lifecycle Assessment (LCA) approach to assessing BioMAT project emissions by analyzing the quantity of lifecycle emissions from BioMAT projects relative to an alternate baseline scenario. The final BioMAT LCA tool is expected to be available for public comment in late 2024.

BioRAM

In 2016, the CPUC implemented Governor Brown's October 2015 Emergency Order Addressing Tree Mortality by establishing the Bioenergy Renewable Auction Mechanism (BioRAM) program. BioRAM uses the RPS standardized renewable auction mechanism (RAM) contract to streamline the procurement process.[96] Subsequently, SB 859 (Chapter 368, Statues of 2016)[97] directed additional BioRAM procurement from the IOUs, resulting in the procurement order of 146 MWs of bioenergy from High Hazard Zones (HHZ)[98] fuel. SB 901 (Dodd, Chapter 626, Statues of 2018) further amended the BioRAM program to add program flexibility and extend certain biomass contracts by five years. SB 1109 (Caballero, Chapter 364, Statues of 2022) further extended certain eligible biomass contracts by a minimum of five years but not to exceed fifteen years.

To implement SB 1109, the CPUC approved Resolution E-5288 which requires the IOUs to extend their existing BioRAM contracts and/or procure new contracts to fulfill their proportional share of the 125 MW established in Resolution E-4805, by December 1, 2023. In order to be eligible for new contracts, biomass resources cannot be located in a federal reserve or extreme non-attainment area for particulate matter or ozone, and must have emissions more stringent than, or equivalent to, the best available retrofit control technology as determined by the local air pollution control or air quality district.

More recently AB 2750 (Gallagher, Chapter 575, Statues of 2024) amends and extends the BioRAM program. The CPUC will be implementing the program revisions in 2025. The table below lists the IOUs' active BioRAM contracts.

Table 25: IOU BioRAM Contract Summary[99]

IOU	Facility Name	Location/County	Capacity (MW)
PG&E	Burney Forest Products	Shasta County, CA	29
PG&E	Shasta Sustainable Resource Management	Shasta County, CA	34
PG&E	Woodland Biomass	Yolo County, CA	25
SCE	Rio Bravo Rocklin	Placer County, CA	24
SCE	Pacific Ultrapower Chinese Station	Tuolumne County, CA	18
SDG&E	Honey Lake Power Company	Lassen County, CA	24
		Total	**154**

Table 25: IOU BioRAM Contract Summary
Data Source: CPUC RPS Database, September 2024

The IOUs collect quarterly data from the BioRAM facilities to track the amount of bioenergy that is being produced from HHZ forest fuel. In addition, the IOUs are required to perform an annual audit to verify

96 *See* https://www.ca.gov/archive/gov39/wp-content/uploads/2017/09/10.30.15_Tree_Mortality_State_of_Emergency.pdf.
97 Senate Bill 859 (Committee on Budget and Fiscal Review, 2016) directs the CPUC to extend contracts for biomass facilities and addresses the statewide tree mortality issue by requiring that 60 percent of forest biomass used to create bioenergy is harvested from Tier 1 and Tier 2 high hazard zones. In 2018, Governor Brown signed SB 901, which modifies the HHZ definition and expands flexibility for certain BioRAM facilities that choose to modify their contracts.
98 For more information on high hazard zone areas, see CALFIRE's website: https://frap.fire.ca.gov/mapping/maps/.
99 SCE's BioRAM contract with Rio Bravo Fresno for 24 MW of capacity ended in September 2022.

and measure the amount of HHZ fuel that BioRAM facilities utilize on a calendar year basis. In 2024, the IOUs completed independent audits on each facility's 2023 HHZ fuel usage.

HHZ fuel usage data for the current IOU-contracted BioRAM facilities is aggregated in Table 26.

Table 26: HHZ Forest Fuel Usage from BioRAM Contracts

Year	BioRAM HHZ % Requirements	Average % of Total Biomass Fuel from HHZ Fuel	Total HHZ Delivered (BDT) [100]	Total HHZ Usage To-Date (BDT)
2017	50%	54.6%	267,745	267,745
2018	60%	56.5%	671,846	939,591
2019	60% and 80%[101]	84%	1,557,050	2,505,641
2020	60% and 80%	79%	862,147	3,367,788
2021	60% and 80%	82.5%	844,527	4,212,315
2022	60% and 80%	84%	951,677	5,136,208
2023	60% and 80%	82%	968,355	6,104,563

Table 26: High Hazard Zone (HHZ) Forest Fuel Usage from BioRAM Contracts
Data Source: CPUC Aggregated Data from IOUs as Described in Annual HHZ Fuel Verification Reports

Interagency Program Planning and Coordination

The CPUC coordinates closely with its sister state agencies on an ongoing basis to promote and implement consistent statewide RPS policies that benefit all Californians. The CPUC, for instance, works with the CEC, California Air Resources Board (CARB), California Independent System Operator (CAISO), and California Department of Forestry and Fire Protection (CAL FIRE) on issues and projects such as: statewide RPS compliance and enforcement, offshore wind development, transmission planning, integration of storage, and wildfire safety and mitigation.

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100 Bone Dry Tons, which commonly accepted to be a 1:1 equivalent with megawatt-hours (MWh), refers to the measurement of biomass that has a 0 percent moisture content.

101 Individual tree mortality BioRAM facility HHZ requirements vary based on the contract. Legislation required that at least 80% of the feedstock must be a byproduct of sustainable forestry management and at least 60% of the feedstock must come from HHZs.

Compliance and Enforcement

The CPUC coordinates closely with the CEC to ensure a consistent policy approach for RPS compliance and enforcement. The CPUC depends on the CEC's compliance verification report to inform its RPS compliance determinations. To perform verifications, the CEC depends on the Western Renewable Energy Generation Information System (WREGIS) to issue and track RECs. In 2022, WREGIS implemented a system overhaul which affected its ability to issue RECs. Throughout 2023 and 2024, the CEC and CPUC monitored WREGIS' efforts to implement corrections. It is expected that the issues will be fully resolved by the end of the year. See the Compliance and Enforcement Section and Appendix B for more details on RPS compliance and enforcement.

Bioenergy Issues and Forest Management

The issue of forest health and its impact on wildfire mitigation intersects with the RPS programs of BioMAT and BioRAM. To ensure that these programs effectively address the State's policy goals, CPUC staff work with stakeholders and other agencies, such as CEC, CARB, Department of Conservation, CAL FIRE, and United States Department of Forestry (USFS) to address program costs and barriers to HHZ woody biomass procurement.

The CPUC participates in regular, ongoing forums that address the State's wildfire mitigation efforts due to high fire threat exacerbated by prolonged drought conditions, bark beetle infestation, and climate change. Specifically, the CPUC is an active participant in the Governor's Wildfire and Forest Resilience Task Force, and RPS staff participate in quarterly meetings with other State and Federal agencies that support forest biomass utilization.

Offshore Wind

The CPUC has participated in the Bureau of Ocean Energy Management (BOEM) California Intergovernmental Renewable Energy Task Force (Task Force) and the Marine Renewable Energy Working Group (MREWG), inter-agency efforts for offshore wind development led by BOEM and the California Ocean Protection Council, respectively. The Task Force serves as a forum to discuss offshore wind issues and concerns; exchange data and information about biological and physical resources, ocean uses and priorities; and facilitate early and continual dialogue and collaboration opportunities. The MREWG coordinates across state agencies to streamline regulatory processes. The CPUC's role in the Task Force and MREWG is to offer insight into the RPS procurement and Integrated Resource Planning (IRP) processes, as well as details of CPUC proceedings that inform procurement need from offshore wind. The CPUC supports offshore wind development for its potential clean energy and reliability benefits but is wary of its high cost of development. The CPUC considers offshore wind in its IRP process, where the resource is available for potential selection in the IRP capacity expansion model. The IRP proceeding continues to refine offshore wind data to optimally inform the procurement process.

On September 15, 2022, the Biden-Harris Administration announced a goal to deploy an additional 15 GW of floating offshore wind by 2035 and decrease the cost to $45/MWh.[102] Such a decrease would be significant given the National Renewable Energy Lab estimated the current levelized cost of energy to be $145/MWh.[103] In December 2022, BOEM held an offshore wind energy lease sale for areas on the Outer Continental Shelf off central and northern California resulting in five leases.[104] The next offshore wind energy lease sales for areas off California's coast are scheduled for 2028.[105]

On July 10, 2024, the CEC adopted a final report[106] that evaluates offshore wind capacity in waters off the California coasts and establishes offshore wind planning goals. Preliminary findings in the report set planning goals of 2-5 gigawatts (GW) of offshore wind by 2030 and 25 GW by 2045, enough electricity to power 3.5 million homes initially and 25 million homes by mid-century. The Pacific Offshore Wind Summit convened the State's policy leaders, including the CPUC, in May 2024 to discuss state and federal offshore wind policies and development progress.

On October 7, 2023, Governor Newsom signed AB 1373 (Garcia, Chapter 367, Statues of 2023) which permits the state to sign long-term contracts for the purchase of electricity from offshore wind facilities. Specifically, AB 1373 provides a mechanism that allows the California Department of Water Resources (CDWR) to centrally procure long-lead time resources, such as offshore wind, upon specific findings by the CPUC that it should be procured to meet the state's growing need for cost-effective resource diversity. The CPUC issued Decision (D.) 24-08-064 on August 29, 2024, which makes an initial need determination under the provisions of AB 1373, under which the CPUC may request that the CDWR procure up to 10.6 GW of electricity from diverse long lead-time resources on behalf of customers of all LSEs under the CPUC's IRP purview. This initial need determination includes up to 7.6 GW of offshore wind. A subsequent informal request may be sent to CDWR within six months of the adoption of D.24-08-064 asking that CDWR initiate procurement activities. Finally, D.24-08-064 also sets a tentative schedule of solicitations, asking CDWR to conduct three rounds of solicitations for offshore wind beginning in 2027.

Hydrogen

The CPUC plays a role to support several state agency efforts for hydrogen development and production for electric generation and long-term energy storage, provided that clean hydrogen[104] is used for electricity production. Presently under Renewable Portfolio Standards (RPS) rules, a facility converting hydrogen gas to electricity may qualify for RPS-certification if the conversion takes place utilizing a fuel-cell and if the hydrogen was derived from a non-fossil fuel or feedstock through a process powered using an eligible renewable energy resource.[107] AB 1921 (Papan, Chapter 556, Statues of 2024) amends the definition of "renewable electrical generation facility" such that fuel cells which only use renewable fuels will be eligible

102 https://www.energy.gov/eere/wind/floating-offshore-wind-shot.
103 Stehly, Tyler and Patrick Duff. 2022 Cost of Wind Energy Review.
104 California Activities | Bureau of Ocean Energy Management (boem.gov).
105 Secretary Haaland Announces New Five-Year Offshore Wind Leasing Schedule | U.S. Department of the Interior (doi.gov).
106 *See* CEC's Final Commission Report: *Assembly Bill 525 Offshore Wind Energy Strategic Plan*, June 2024.
107 Renewables Portfolio Standard Eligibility, Ninth Edition, January 2017 – California Energy Commission.

under the RPS program.[105] This would limit the use of hydrogen to only that which is from renewable fuels, as defined in Public Resource Code Section 25741(a)(1).

CARB, pursuant to SB 1075 (Skinner, Chapter 363, Statues of 2022) is coordinating with the CPUC and CEC to produce a comprehensive report on hydrogen that will cover the deployment, development, and use of hydrogen across all sectors as a key part of achieving the State's climate, air quality, and energy goals. Additionally, the CPUC continues to assess the feasibility and safety implications of utilizing clean hydrogen as a decarbonization strategy for the natural gas system and hard-to-electrify industries. In D.22-12-055 the CPUC approved Southern California Gas Company (SoCalGas) to proceed with an initial phase of feasibility studies for the Angeles Link Project, which would be a gas transmission pipeline dedicated for clean renewable hydrogen transport to serve hard to electrify uses in the Los Angeles Basin.

Phase One of the project began early 2023 which included feasibility studies that were completed in mid-2024. Completion of Phase One is expected to take 12-18 months. Three additional phases will follow prior to Angels Link Project being built.[108] Additional hydrogen related projects are either in development or are being pursued via a number of different opportunities. In D.22-12-057, the CPUC ordered PG&E, Southwest Gas Corporation, SoCalGas, and SDG&E to continue filing biomethane-related reports and to develop pilot projects to evaluate standards for the safe injection of renewable hydrogen into California's pipeline system by designing and testing real-world hydrogen blending program. Further, in the Joint IOU Amended Application 22-09-006, the IOUs request to establish hydrogen blending demonstration projects.

The Clean Hydrogen Program was established by the CEC pursuant to AB 209 (Chapter 251, Statues of 2022) and also promotes hydrogen demonstration projects by providing financial incentives to eligible in-state projects that demonstrate or scale-up hydrogen projects that produce, process, deliver, store, or use hydrogen derived from water using eligible renewable energy resources, or produced from these eligible renewable energy resources.[109] Recently enacted SB 1420 (Caballero, Chapter 608, Statues of 2024) also supports development of hydrogen production facilities in that it allows certain hydrogen production facilities and onsite storage and processing facilities to be eligible for centralized permitting and expedited review under the California Environmental Quality Act (CEQA).

In addition to various projects and programs, market and economic interest in hydrogen has recently occurred. Notably, in 2022, the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES), a public-private partnership was developed to decarbonize California's public transportation, heavy duty trucking, and port operations by two million metric tons a year. In July 2024, the U.S. Department of Energy (DOE) and ARCHES signed a $12.6 billion agreement to build a clean, renewable Hydrogen Hub in California, including $1.2 billion in federal funding. The agreement follows California's 2023 selection as one of the seven hydrogen hubs in the country. The CPUC directed SoCal Gas (in D.22-12-055, OP 3d) to

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108 SoCal Gas Angeles Link Quarterly Report (Phase One) (April 1, 2024 through June 30, 2024).

109 California Energy Commission, Clean Hydrogen Program: www.energy.ca.gov/programs-and-topics/programs/clean-hydrogen-program.

join ARCHES, to form a public-private California partnership to accelerate the deployment of clean, renewable hydrogen projects and to apply for federal funding for a localized clean energy hydrogen hub.

Transmission Development Supporting RPS Implementation

The CPUC works with other State agencies and organizations in the planning of transmission, necessary to support the delivery of renewable energy to California homes and businesses. Transmission planning can take several years from the initial Transmission Planning Process with the California Energy Commission and the CAISO to the CPUC's role in required environmental review. The CPUC is responsible for permitting transmission projects and ensuring that transmission-related projects comply with the California Environmental Quality Act (CEQA). CPUC staff perform detailed CEQA analysis to identify and mitigate environmental impacts from large-scale utility projects and to identify alternatives to the projects. Not all transmission projects require permits or environmental review from the CPUC. Of the transmission projects implemented or currently in progress by the IOUs, less than 6% required a CPUC permit

The CPUC is the lead CEQA agency for the five transmission projects listed within this section. Each of the transmission projects that this section focuses on supports RPS resources and are in the active permitting, construction, and/or post-construction phases. The following section, SB 1174 – Assessment of Renewable and Storage Resources Associated with Delayed Transmission Projects, focuses on transmission projects that support renewable generation and storage resources and that have been delayed.

SCE's West of Devers 220kV Upgrade Project

The West of Devers Upgrade was approved in D.16-08-017 (Application A.13-10-020) by the CPUC. After a lengthy CEQA/National Environmental Policy Act (NEPA) review in conjunction with the Bureau of Land Management, construction of this major project was completed, and on May 14, 2021, the project was fully energized. Commercial operation of the line began six months ahead of schedule in May 2021. This project will allow deliverability of new renewable resources — more than 7,000 MW of renewable and battery energy storage in the coming years — from desert areas in the eastern part of California to the population centers of the Inland Empire and San Gabriel Valley. The total cost of the project was $740 million, with Morongo Transmission investing $400 million.

SCE's Eldorado – Lugo – Mojave Series Capacitor Project

SCE filed an application (A.18-05-007) with the CPUC for a Certificate of Public Convenience and Necessity (CPCN) on April 19, 2019, requesting to construct the Eldorado – Lugo – Mojave ("ELM") 500 kV Series Capacitor Project. The project had previously been approved through the CAISO's 2013-2014 Transmission Planning Process. SCE proposed the ELM Project to deliver electricity from renewable and conventional generation resources outside of California to help meet growing electricity demand in the region, as well as to reduce GHGs.

The ELM Project consists of the following major components: 1) Construct two new 500 kV mid-line series capacitors (the proposed Newberry Springs Series Capacitor and Ludlow Series Capacitor) and associated equipment; and 2) Relocate, replace, or modify existing transmission, sub-transmission, and distribution facilities at approximately 12 locations along the Eldorado-Lugo, Eldorado-Mohave, and Lugo-Mohave 500 kV Transmission Lines to address 14 potential overhead clearance discrepancies.

The CPUC approved the CPCN for the ELM Project on August 27, 2020, in D.20-08-032, with a cost cap of $239 million (including contingency costs). Preconstruction compliance review has been completed and Notice to Proceed (NTP) #1 was issued December 14, 2020, NTP #2 was issued April 1, 2021, NTP #3 was issued May 19, 2021, and NTP #4 was issued June 8, 2021. Construction on California non-federal lands began January 2021.

On May 24, 2023, SCE filed a Petition for Modification (PFM) to its application, requesting the cost cap be increased to $295 million (2019). Construction is now scheduled to continue through May 2025.

Delaney Colorado River Transmission (DCRT) Ten West Link Project

The CPUC approved the Ten West Link (TWL) Project in November 2021 to increase access to out-of-state resources and lower costs to California ratepayers, primarily through production cost benefits and increased delivery of renewable generation in the Southwest. The project also provides reliability and policy benefits and congestion relief in addition to the economic benefits.

The proposed project includes installation of a 500-kV transmission line, transmission supporting structures between 72 and 190 feet in height, conductors, overhead ground wire, and a new series compensation[110] system substation. This 500-kilovolt (kV) transmission line will traverse approximately 114 miles, including a 17-mile segment in California. The portion of the proposed project in California begins at the Colorado River Substation west of the City of Blythe and runs eastward to the Colorado River near the Interstate 10 corridor in western Riverside County, California.

The proposed project will increase transmission capacity by 3,200 megawatts and provide interconnection capability for new energy projects located near the proposed project. In November 2021 the CPUC issued D.21-11-003 granting Delaney Colorado River Transmission (DCRT) a CPCN for the Ten West Link Project, with a cost cap of $389 million (including contingency costs).[111] On June 9, 2023, DCRT made a filing with the Federal Energy Regulatory Commission (FERC) in Docket ER23-2309 requesting recovery of costs totaling $553 million. The construction of the Project is complete, and CAISO indicated an in-service date of July 1, 2024.

110 Series compensation is the method of improving the system voltage by connecting a capacitor in series with the transmission line.

111 Selected as a regional project in the CAISO's 2013-2014 Transmission Plan, Ten West Link, despite being mostly in Arizona, is being paid for in full by California ratepayers.

LS Power Grid California (LSPGC) Collinsville 500/230 kV Substation Project

LS Power Grid California, LLC (LSPGC) filed an application for a CPCN for the Collinsville 500/230 Kilovolt (kV) Substation Project on July 29, 2024 (Application No. A.24-07-018). The CAISO 2021-2022 Transmission Plan identified the Proposed Project as a needed upgrade to the California electric grid. The proposed project is located in Solano, Sacramento, and Contra Costa counties within an existing regional transmission system that provides electricity to the northern Greater Bay Area.

The main components of the Proposed Project include the following:

- Constructing a new 500/230 kV substation. The proposed Collinsville Substation would be located to the south and west of Stratton Lane and approximately 0.75-mile northeast of the unincorporated community of Collinsville.
- Constructing two new approximately 1.5-mile-long, single-circuit 500 kV transmission line segments extending to interconnect Pacific Gas and Electric Company's (PG&E) existing Vaca Dixon-Tesla 500 kV Transmission Line into the proposed LSPGC Collinsville Substation.
- Constructing a new approximately 6-mile-long, double-circuit 230 kV transmission line to connect the proposed LSPGC Collinsville Substation to PG&E's existing Pittsburg Substation, with approximately 4.5 miles of submarine cables running beneath the Sacramento-San Joaquin River Delta waterways.
- Extending and connecting an existing PG&E 12 kV distribution line to the proposed LSPGC Collinsville Substation.
- Constructing new telecommunications paths to the proposed Collinsville Substation, a new microwave tower at the proposed substation, and a new fiber optic path between existing fiber in the City of Pittsburg and the proposed substation.
- Modifying PG&E's existing Vaca Dixon and Tesla Substations, including line relays and microwave towers to support the new Collinsville Substation interconnection.

The Project would facilitate deliverability of load from existing and proposed renewable generation projects in the northern Greater Bay Area, including offshore wind in the Humboldt area, and corresponding progress toward achieving California's RPS goals in a timely and cost-effective manner by California utilities.

LSPGC Manning 500/230 kV Substation Project

LSPGC filed an application for a CPCN for the Manning 500/230 Kilovolt (kV) Substation Project on June 28, 2024 (Application No. A.24-06-017).[112] The CAISO 2021-2022 Transmission Plan identified this proposed project, located in western Fresno County, as a needed upgrade to address reliability and capacity issues on the existing PG&E system in the Fresno area as well as to facilitate the advancement of renewable

112 More information on projects that the CPUC is overseeing the California Environmental Quality Act (CEQA) process can be found at: https://www.cpuc.ca.gov/ceqa.

energy generation in the region. Specifically, this project is estimated to allow deliverability of approximately 44 MW of new solar generation in the Westlands area of the San Joaquin Valley.

The proposed project includes construction and operation of the new Manning Substation; construction of one new overhead double-circuit 230 kV transmission line that would extend approximately 12 miles from the proposed new Manning Substation to interconnect with PG&E's existing Tranquillity Switching Station; interconnection of PG&E's existing Los Banos-Midway #2 500 kV transmission line, Los Banos-Gates #1 500 kV transmission line, and Panoche-Tranquillity Switching Station #1 and #2 230 kV transmission lines to the proposed new Manning Substation; reconductoring of approximately seven miles of PG&E's existing Panoche-Tranquillity Switching Station #1 and #2 230 kV transmission lines; and extension of an existing underground fiber cable adjacent to PG&E's existing Tranquillity Switching Station to the optical ground wire of the new 230 kV transmission line. The 2021-2022 CAISO Transmission Plan estimated that this project will cost between $325 million and $485 million.

The CPUC is preparing an Initial Study and Mitigated Negative Declaration (IS/MND) to evaluate the environmental impacts of the proposed project, with a final version of the IS/MND expected to be released in the second quarter of 2025 and a CPUC decision on the CPCN application expected by early 2026. The CAISO-identified in-service date is June 1, 2028.

SB 1174 – Assessment of Renewable and Storage Resources Associated with Delayed Transmission Projects

Background

SB 1174 (Hertzberg, Chapter 229, Statues of 2022) requires electrical corporations that own transmission facilities to prepare and submit to the CPUC annually, a report on any changes to previously reported in-service dates (ISDs) of transmission and interconnection facilities necessary to provide transmission deliverability to eligible renewable energy resources or energy storage resources that have executed interconnection agreements.

Additionally, SB 1174 requires that the CPUC provide a systemwide assessment of delays to interconnection or transmission approvals for eligible renewable energy resources or energy storage resources based on the annual information provided by transmission owners. Data included with transmission owner reporting and the assessment include all transmission and interconnection projects and generation resources currently in development, as well as any transmission and interconnection projects that were completed on or after January 1, 2019, and experienced a delay of in-service from the original in-service date.

As electrical corporations and participating transmission owners (PTOs), PG&E, SCE, and SDG&E reported data related to SB 1174 within their 2024 Draft RPS Procurement Plans.[113] Their data on eligible renewable energy resources and energy storage resources were considered for the following systemwide assessment. SDG&E reported that they had no delayed transmission and interconnection projects, so the bulk of the CPUC's assessment summarized below focuses on the systems owned by PG&E and SCE. Additionally, in September 2024, all three investor-owned utilities (IOUs) filed a Motion to Update for their 2024 Draft RPS Procurement Plans that included updated SB 1174-related information and data. Due to time constraints, only the updated data was considered for this assessment, but the IOUs updated narratives on SB 1174 requirements were not. The narratives within the original 2024 Draft RPS Procurement Plans were considered, however.

Transmission Overview

The IOUs were required to report all transmission and system network upgrades (interconnection) that are currently in development and or were completed on or after January 1, 2019 and experienced a delay of in-service from the original in-service date. These transmission, interconnection, and system network upgrades are hereinafter referred to as "transmission projects". According to the IOUs, a large number of transmission project in-service date delays can be attributed to customer actions, land rights, materials, and other issues. These reasons for delays are discussed in more detail in this assessment.

Additionally, the IOUs were required to report on currently in development renewable generation and storage resources. The SB 1174 reporting complements a variety of other reporting underway related to interconnection and transmission, including:

- The IOUs report regularly on their immediate past and near-term future transmission portfolio (including but not limited to transmission projects that are associated with generation and storage resource development) in the CPUC's Transmission Project Review report (TPR)[114], and the SB 1174 data discussed herein represents a subset of transmission projects that are currently in development or were completed on or after January 1, 2019.
- The California Independent System Operator (CAISO) has routinely started publishing information about generator and storage resources available for near-term interconnection, and the resources reported on by the CAISO are either (1) not dependent on transmission; (2) only dependent on relatively easier to develop remedial action schemes; and (3) dependent on transmission already under construction.[115]

113 Non-electrical corporations (non-IOUs) that are participating transmission owners did not participate in the SB 1174 data collection process in 2024.
114 More information on the TPR can be found here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/transmission-project-review-process.
115 More information on the CAISO Report on Resources Available for Near Term Interconnection can be found here: https://www.caiso.com/generation-transmission/generation/generator-interconnection.

The SB 1174 required reporting analyzed here demonstrates that a large percentage of interconnection projects for generators and storage projects are subject to timelines that can be severely impacted by transmission project timelines. The IOUs reported delays of in-service dates for 119 out of 167 (71 percent) of transmission projects related to interconnections, including:

- PG&E reported 58 transmission projects linked to interconnection, 42 of which (72 percent) were reported as delayed.
- SCE reported 93 transmission projects linked to interconnection, 77 of which (83 percent) were reported as delayed.
- SDG&E reported 16 transmission projects linked to interconnection, none of which were reported as delayed.

In the case of SDG&E, the Original In-service Date for their reported transmission projects were labeled as a "mutually agreed date". This may indicate that SDG&E interpreted an Original In-service Date for a transmission project differently than the other IOUs.

Table 27: Reported Transmission Project Delays by IOU

IOU	Transmission Projects	Transmission Projects Delayed	Percent of Transmission Projects Delayed
PG&E	58	42	72%
SCE	93	77	83%
SDG&E	16	0	0%
TOTALS	**167**	**119**	**71%**

Table 27: Reported Transmission Project Delays by IOU
Data Source: PG&E, SCE, SDG&E 2024 SB 1174 Data Request (within their 2024 Draft RPS Procurement Plans)

Categorizing Risk of Transmission Timelines on Renewable Generation and Storage Resource Development Timelines

To assess the risk of transmission timeline delays on the development of interconnection of renewable generation and storage resources, CPUC staff reviewed the dependencies between the projects in the interconnection queue and the transmission projects. The 119 delayed transmission projects described above are dependencies for 172 renewable energy and energy storage resources (defined as a queue position) with executed interconnection agreements, representing 28.4 GW of new capacity for the electric grid.[116]

116 The 28.4 GW of renewable energy and energy storage resources discussed in the assessment do not represent the total of resources currently in queue, but only the resources reported as dependent on in-development transmission projects and reported by the IOUs within their draft 2024 RPS Procurement Plans SB 1174 data.

However, based on the data provided in the SB 1174 Data Request, staff estimates that only 16 GW of the 28.4 GW of renewable generation and storage resources reported by the IOUs are currently impacted by delayed transmission projects. This 16 GW estimate includes only generation and storage resources dependent on already delayed transmission projects. The remaining 12.4 GW of the 28.4 GW are not yet delayed or currently at risk of being delayed, despite being dependent on delayed transmission projects. If transmission projects were to be delayed further, then the remaining 12.4 GW of the 28.4 GW could be impacted as well.

For additional context as to the magnitude of these 16 GW, CPUC staff estimate that over 20 GW of new clean generation and storage resources have come online in California since January 2020, despite any delays in transmission projects.[117] Additionally, the 28.4 GW discussed in this assessment does not include renewable generation and energy storage resources reported that are not dependent on in-development transmission projects.

In some cases, the IOUs were not able to provide details on the transmission projects that a generation or storage resource was dependent on, as the IOU may not be both the transmission project owner and the primary point of interconnection (i.e. the PTO) for the dependent generation or storage resource owner.

To consider the current and potential impacts of transmission project delays on dependent generation and storage resources, staff developed a categorization rubric to assess delays. Reported generation and storage resources were assigned into one of three categories: Not Delayed, At Risk, and Delayed. The Delayed category provides insight into current impacts while the At Risk category provides additional insight into possible and probable impacts. The Not Delayed category provides additional context to the significance of Delayed and At Risk dependent generation and storage resources. These three categories are defined as:

1) Not Delayed: The generation or storage resource's in-service date is scheduled after the current in-service date of the transmission project it depends on, or the generation or storage resource does not depend on any of the listed transmission projects.
2) At Risk: The generation or storage resource's current in-service date is scheduled before the current in-service date of the transmission project that it depends on; however, the delayed transmission project this resource depends on is associated with a median delay time which puts this resource at risk of becoming delayed.
3) Delayed: The generation resource's current in-service date comes before the current in-service date of the transmission project that it depends on.

Figure 13 below illustrates the total capacities for generation and storage resources reported, categorized by the three categories described above: At Risk, Delayed, Not Delayed.

117 See Briefing on Recent Resource Development, available at www.cpuc.ca.gov/trackingenergy.

Figure 13: Renewable Generation and Storage Resources (28.4 GW) as of September 2024 Impacted by Delayed Transmission Projects

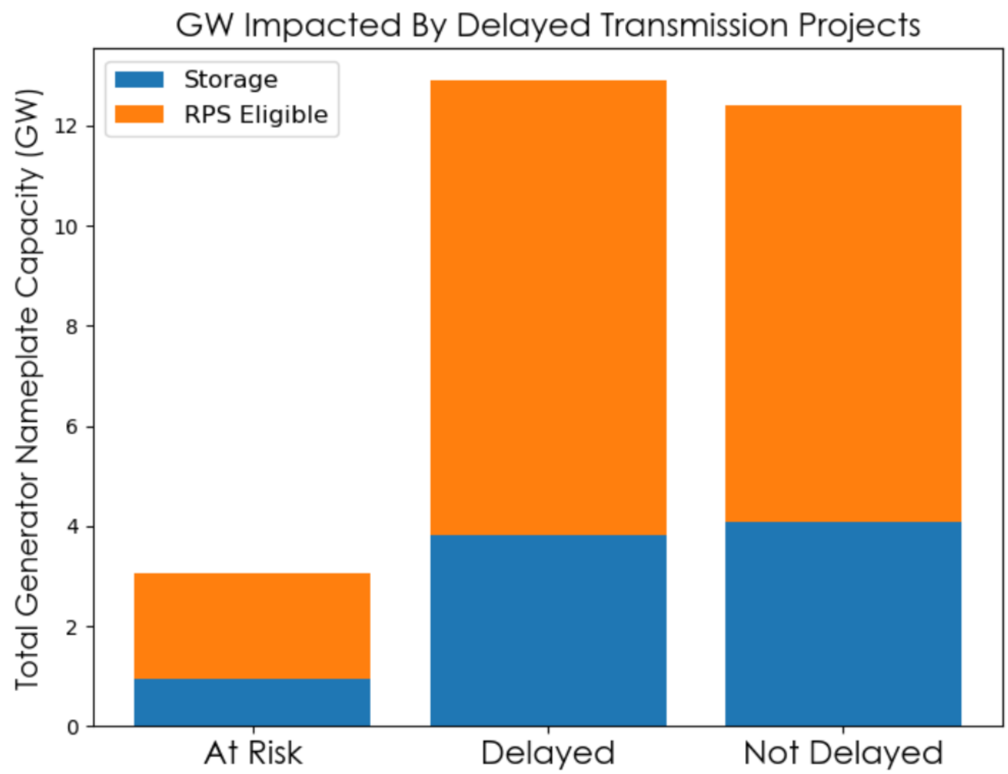

Figure 13: Renewable Generation and Storage Resources (28.4 GW) as of September 2024 Impacted by Delayed Transmission Projects
Data Source: PG&E, SCE, SDG&E 2024 SB 1174 Data Request (within their 2024 Draft RPS Procurement Plans)

At Risk resources were categorized based on the median delay times for the delay reason of the transmission project they depend on. The median delay times by delay reason are further detailed later in the assessment. Figure 14 below illustrates an example of a transmission project that has experienced a delay due to Supply Chain constraints, and the delay's effects on dependent generation resources. In this example, generation resources one to three have been delayed because the transmission project that they depend on now has an in-service date that is past the generation resource's in-service dates due to Supply Chain-related delays. Generation resource four is at risk of being delayed as its in-service date is within the median delay time for transmission projects that have been delayed due to Supply Chain reasons, but not yet delayed because it still has an in-service date after the transmission project current in-service date. Generation resource five is not delayed or expected to become delayed due to its in-service date being after the transmission project's in-service date and after the median delay time for Supply Chain delays.

Figure 14: Example Illustration of Not Delayed, At Risk, and Delayed Generation Resources

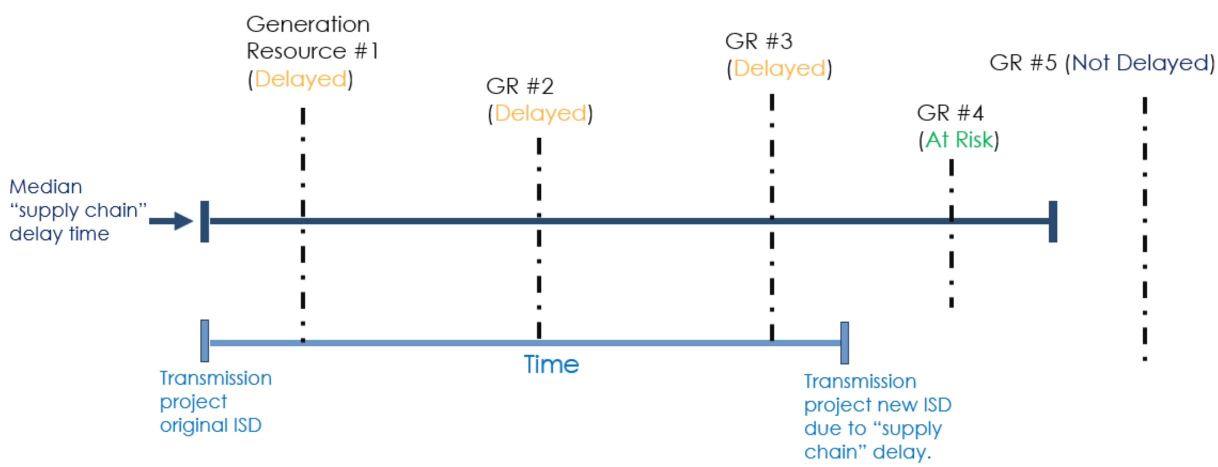

Figure 14: Example Illustration of Not Delayed, At Risk, and Delayed Generation Resources

It is worth noting that the assessment focused solely on eligible renewable energy resources and energy storage resources that have been impacted by transmission delays. The assessment did not consider other potential reasons for eligible renewable energy resources and energy storage resources being delayed, and resources categorized here as Not Delayed can still experience delays and in-service date changes that are not related to the transmission projects that they depend on.

Impact of Transmission Project Delays on Renewable Generation and Storage Resources

Out of the 28.4 GW of renewable generation and storage resources reported by the IOUs, approximately 19.5 GW are RPS eligible resources, and approximately 15.9 GW of the 28.4 GW are RPS eligible resources that are dependent on transmission projects that have been delayed. The remaining resources were comprised of storage resources that are not RPS eligible.

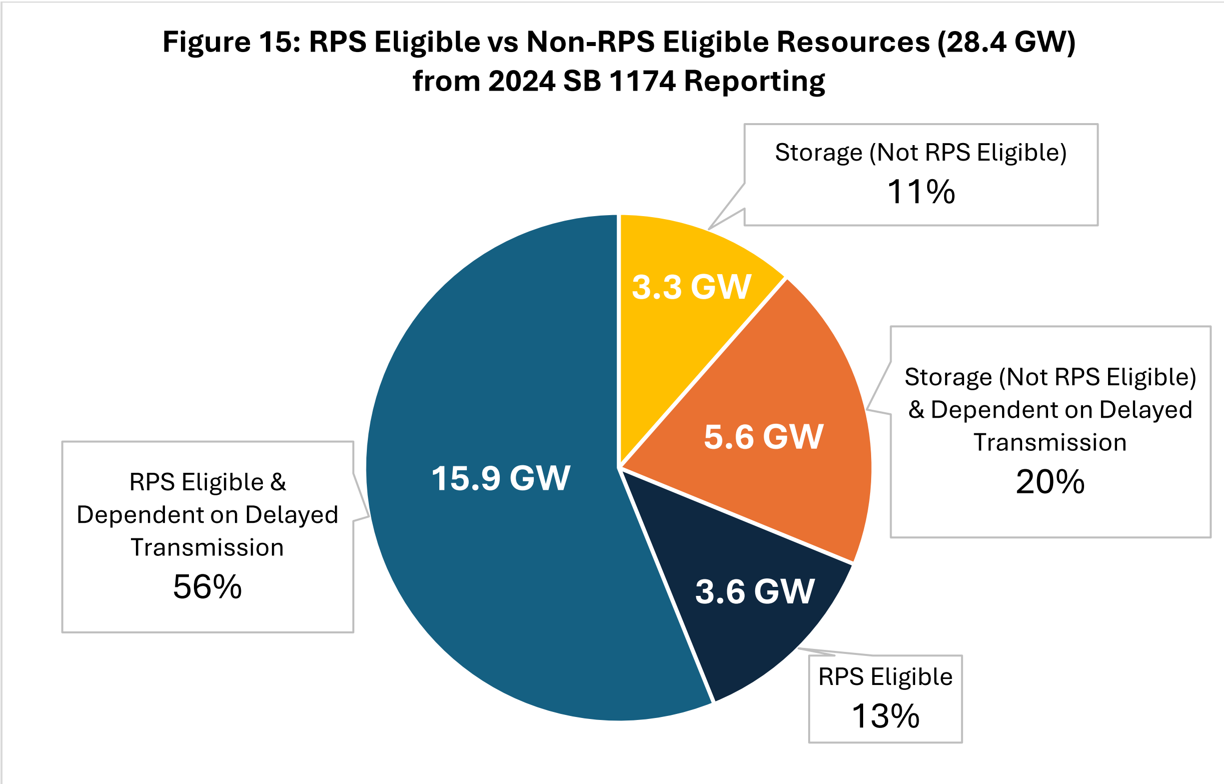

Figure 15: RPS Eligible vs Non-RPS Eligible Resources (28.4 GW) from 2024 SB 1174 Reporting
Data Source: PG&E, SCE, SDG&E 2024 SB 1174 Data Request (within their 2024 Draft RPS Procurement Plans)

It is important to note that of the 15.9 GW of RPS eligible resources dependent on delayed transmission projects, not all of these resources are considered Delayed or At Risk, with 9 GW of the 15.9 GW being impacted (delayed or at risk) as described below.

Based on the data reported by the IOUs, staff estimate that between SCE's and PG&E's combined approximately 28.4 GW of in-development RPS eligible and storage resources, 13 GW (45 percent) are projected to be delayed because of delayed dependent transmission projects, with an additional 3 GW (10 percent) of these resources at risk of becoming delayed (16 GW total impacted). Of the 13 GW of resources projected to be delayed due to delayed dependent transmission projects, 9 GW are RPS eligible resources while the remaining 4 GW are storage (mostly battery) resources.

Staff also estimate that for SCE, 50 percent of in-development renewable generation and storage resources are currently projected to be delayed, and 17 percent are currently at risk of becoming delayed, due to delayed transmission projects that they depend on. For PG&E, 39 percent of in-development generation resources are currently projected to be delayed, and three percent are currently at risk of becoming delayed, due to delayed transmission projects that they depend on.

Reasons For Transmission Project Delays

From the transmission project data reported by the IOUs, delayed transmission projects experienced an overall median delay time of 24 months (two years). However, this is not necessarily representative of a typical delay for transmission projects and the specific reason for a delay provides more comprehensive insight. Transmission project development data is extremely difficult to track because projects can change over time and the timelines can change numerous times over project development lifetime. As a project moves through its development lifecycle from planning through engineering, permitting, funding and construction – various factors influence schedule. Likewise, generation and storage resources have schedules that are constantly being reassessed, for various reasons, including contracting, permitting, and transmission dependency delays.

Based on the data request template provided, IOUs self-reported transmission delays into 14 categories or reasons for changes to in-service dates. Based on the template provided, the IOUs were only able to indicate a single delay reason, although it may be possible that multiple factors have contributed to a transmission project's delay. IOUs were also able to indicate a category labeled as "Other" for projects where the delay reason was not easily categorizable from the list of delay reasons provided by the CPUC. Figure 16 below illustrates the varying median delays by in-service date change reason.

Figure 16: Number of Delayed Transmission Projects and Median Delay Time by Transmission Project Delay Reason

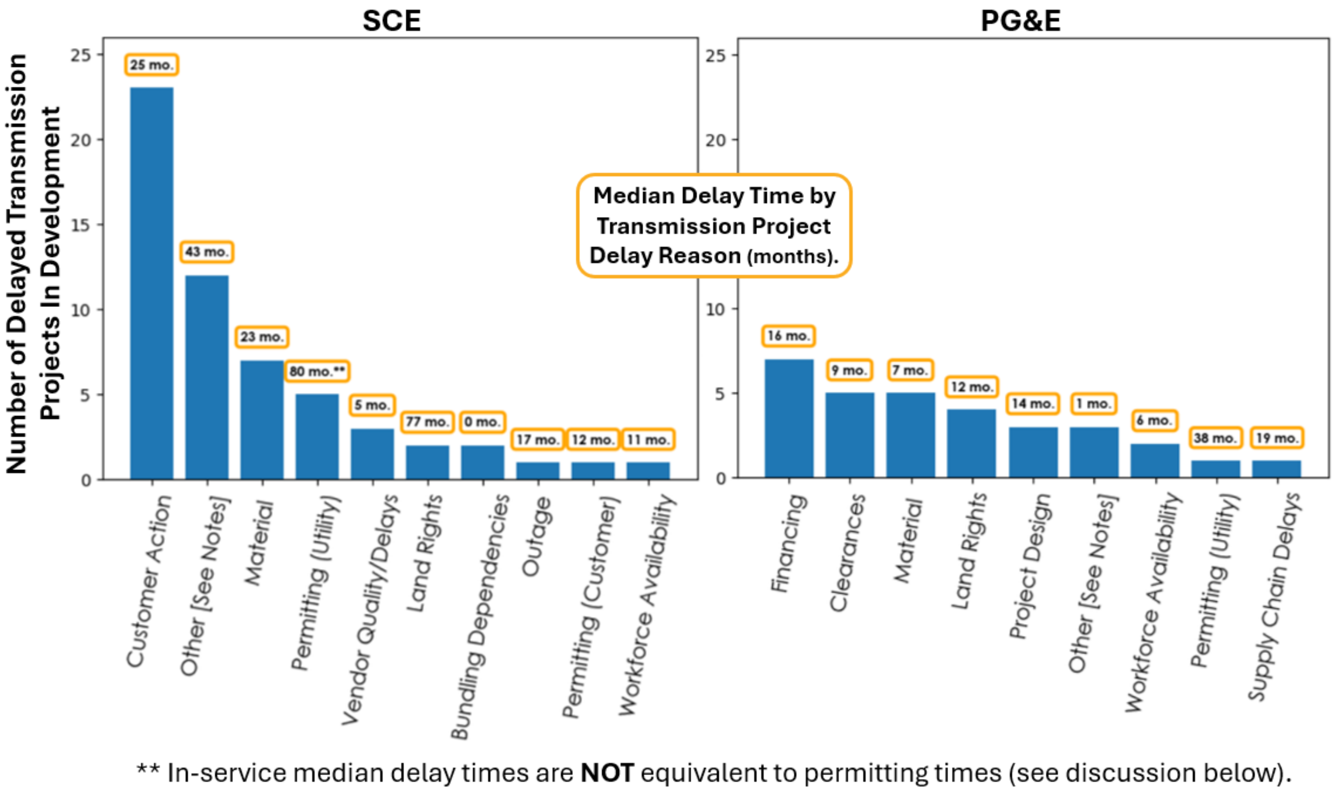

Figure 16: Number of Delayed Transmission Projects and Median Delay Time by Transmission Project Delay Reason
Data Source: PG&E and SCE 2024 SB 1174 Data Request (within their 2024 Draft RPS Procurement Plans)

Figure 16 above illustrates that between PG&E and SCE, the median delay time varies significantly in general, but also between the various delay reasons.

In SCE's 2024 Draft RPS Procurement Plan, SCE provides additional explanation for both the Customer Action and Other delay reasons. SCE explains that "Customer Action includes generation projects suspending their projects and also phasing or pushing out their in-service dates through the CAISO's Material Modification Assessment ("MMA") process. Furthermore, Customer Action can also include Municipal Utilities putting approved transmission projects on hold to explore alternatives, such as additional undergrounding." Customer Action could also include projects where customers are changing the project scope or timing in response to a transmission delay. Although SCE does not provide significant elaboration, SCE provides three specific reasons for categorizing a delayed transmission project reason as Other: Prioritization, Scope Change, and Third-Party Transmission Builder.

Out of the 20 SCE transmission projects delayed for Other, SCE noted that 12 were for Prioritization. Although notes to explain the Prioritization delays within the 2024 SB 1174 Data Reporting Template varied for these 12 projects, as an example SCE cited for several of these projects that, "based on area needs, the projects within the region were prioritized by internal transmission planning and grid controls thus impacting this projects construction start and in-service date. In addition, delays in predecessor projects in the area have impacted these dates." The second largest reason SCE defined for Other was Scope Change at five projects.

Although Utility Permitting has the longest median delay time for both IOUs, in-service date changes (or median delay times) are not equivalent to actual permitting times. Upon further examination of the six delayed SCE projects that CPUC staff used to calculate the median Utility Permitting delay time, staff could only verify that four of these transmission projects have ongoing or completed permitting, with a median permitting time of 49.5 months. For PG&E, only one delayed transmission project was attributed to utility permitting-related reasons. SCE defines Utility Permitting as "environmental activities required by the CEQA and the National Environmental Policy Act", while PG&E does not specifically define Utility Permitting. CPUC staff note that permitting includes encroachment permits, local agency permits, and resources agency permits.

Neither IOU provided any additional context on these delays within their 2024 Draft RPS Procurement Plans, other than SCE categorizing Utility Permitting as one of its top delay reasons and defining it as quoted above. Furthermore, the IOUs did not identify the lead permitting agencies for these transmission delays, but permits can be required at the local, state (including the CPUC), and federal level.

Capacity of Impacted Generation

Table 28 below displays for each transmission project delay reason reported by the IOUs, the combined number of transmission projects delayed for that reason, and the dependent RPS eligible and storage resource generation from the greatest GW to lowest GW. It should be noted that generation and storage resources in Table 28 may be counted within multiple In-Service Date Change Reasons if the generation resource is dependent on multiple transmission projects that have been delayed for different reasons. Despite Other being the most cited delay reason as discussed above (26 projects), these projects did not represent the total highest amount of potentially impacted dependent RPS eligible and storage resources in terms of generation.

Table 28: IOU In-Service Date Change Reasons and Generation Impacts

In-Service Date Change Reason	Transmission Projects Impacted	Dependent Generation - RPS Eligible (GW)	Dependent Generation - Non-RPS Eligible Storage (GW)	Total Dependent Generation - RPS Eligible & Storage (GW)
Customer Action	25	6.46	2.13	**8.59**
Other	26	4.71	1.06	**5.77**
Material	14	2.48	3.27	**5.75**

Table 28: IOU In-Service Date Change Reasons and Generation Impacts				
In-Service Date Change Reason	**Transmission Projects Impacted**	**Dependent Generation - RPS Eligible (GW)**	**Dependent Generation - Non-RPS Eligible Storage (GW)**	**Total Dependent Generation - RPS Eligible & Storage (GW)**
Clearances	5	3.68	0.15	**3.83**
Financing	9	1.14	2.21	**3.35**
Permitting (Utility)	8	1.85	1.18	**3.04**
Bundling Dependencies	13	2.68	0.09	**2.77**
Vendor Quality/Delays	3	1.90	0.00	**1.90**
Land Rights	6	1.51	0.03	**1.55**
Project Design	3	0.71	0.13	**0.84**
Permitting (Customer)	2	0.20	0.00	**0.20**
Workforce Availability	3	0.00	0.10	**0.10**
Supply Chain Delays	2	0.00	0.00	**0.00**
Outage	1	0.00	0.00	**0.00**

Table 28: IOU In-Service Date Change Reasons and Generation Impacts
Data Source: PG&E, SCE, SDG&E 2024 SB 1174 Data Request (within their 2024 Draft RPS Procurement Plans)

Table 28 above demonstrates that transmission projects delayed due to Customer Action have the largest amount of dependent eligible renewable energy and storage resources (8.59 GW), despite being the delay reason with the second most impacted transmission projects (25), behind Other (26). However, both delay reasons represent the top two delay reasons in terms of both total transmission projects impacted and total dependent renewable energy storage resources. As noted above, there was a large discrepancy in the number of delayed transmission projects due to Other and Customer Action between PG&E and SCE. Material is the third largest cited delay reason in terms of both the number of projects (14) and dependent eligible renewable energy and storage resources (5.75 GW), just behind Other (5.77 GW). These top three delay reasons represent 53 percent of the dependent eligible renewable energy and storage resources GW in Table 28. Anecdotal reports of transformers having 36-48 month lead times instead of the pre-pandemic 12 month lead time could be a factor in Material delays. Additionally, utilities have typically used a small number of preferred suppliers to streamline the operation of their systems; but lead times have forced the utilities to start considering additional suppliers for transformers.

Figure 17 below breaks down the number of GW of in-development resources categorized as (At Risk, Not Delayed, and Delayed) for each delay reason (Customer Action, Permitting (Utility), etc.). In Figure 17 generation and storage resources (GW) that are dependent on multiple transmission projects are counted multiple times, highlighting the impact of resources that depend on multiple delayed transmission projects. Figure 17 emphasizes the large impact of SCE transmission projects delayed due to Customer Action and Other (Scope Change and Prioritization). This figure also emphasizes the large impact to PG&E resources by transmission projects delayed due to Land Rights and Material.

Figure 17: Status of Dependent Generation and Storage Resources by Transmission Project Delay Reason

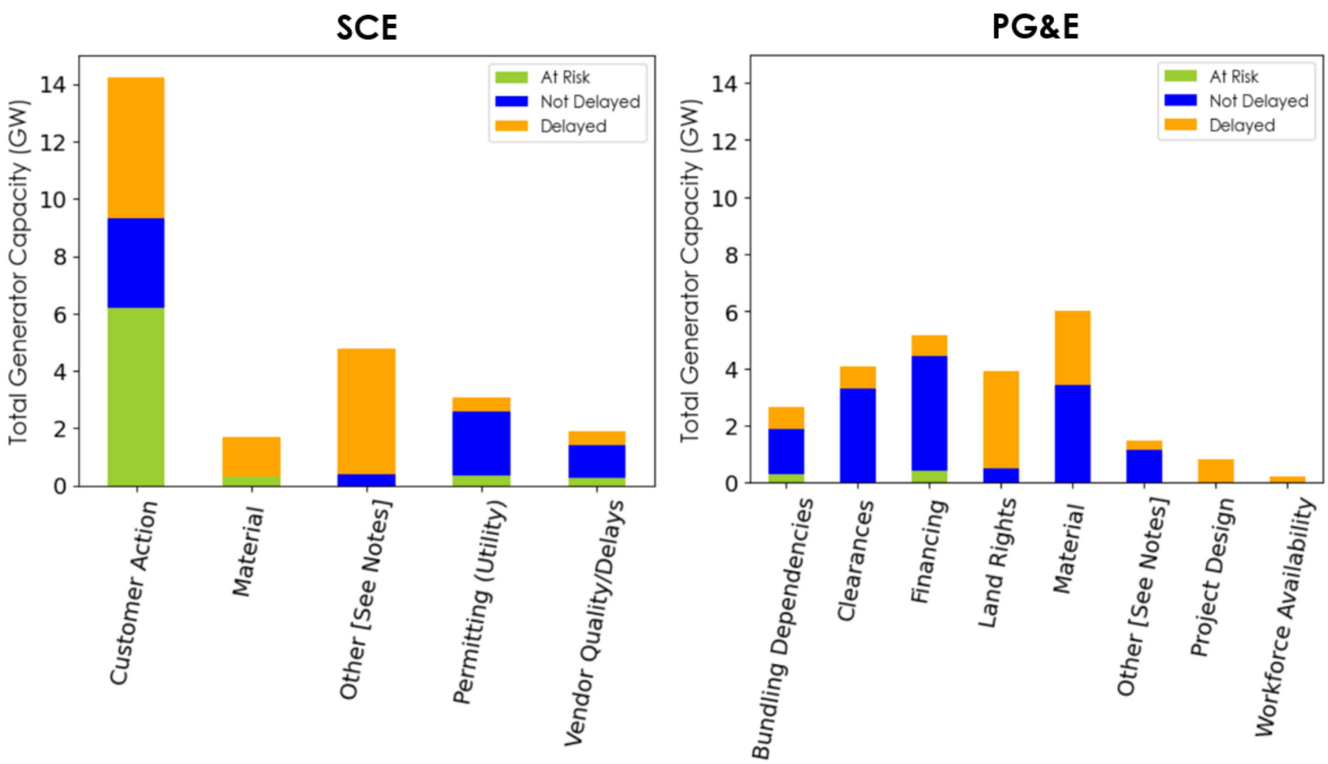

Figure 17: Status of Dependent Generation and Storage Resources by Transmission Project Delay Reason
Data Source: PG&E and SCE 2024 SB 1174 Data Request (within their 2024 Draft RPS Procurement Plans)

PG&E does not provide any significant context for Project Design within its 2024 Draft RPS Procurement Plans but provides some insight into Material-related delays: "material delivery issues and associated delays were a key source of delay from our suppliers."

High-Impact Delayed Transmission Projects

The 11 delayed transmission projects listed in Table 29 below have the largest amounts of delayed or at risk dependent resources (GW) out of all the transmission projects reported by the IOUs. Overall, 19 resources (9.2 GW) are expected to be delayed or at risk by these 11 transmission projects, representing 32 percent of the RPS eligible and storage resources reported by the IOUs. Some of these resources are being delayed or put at risk by multiple delayed transmission projects, and in Table 29 below their generation (GW) is counted multiple times (once for each transmission project they depend on), to capture the relative impact of each of these high impact delayed transmission projects.

Table 29: Delayed Transmission Projects with Highest Delayed or At Risk Dependent Generation (GW)

IOU	Transmission Project Name	Delayed Transmission Project ID	In-Service Date Change Reason	Delayed or At Risk Resource Queue numbers	Delayed or At Risk Generation (GW)
SCE	Lugo Substation Upgrade	8029	Other (Prioritization)	Q1796, Q1636, Q1643, Q1757, Q1761, Q1764, Q1768, Q2042	3.69
SCE	Tehachapi Centralized Remedial Action Schemes: monitoring infrastructure addition	8355	Customer Action	Q1631, Q1632	2.12
SCE	WOCR Centralized Remedial Action Schemes Inland/Devers Extension Additional Monitoring at Wildlife Sub	8381	Customer Action	Q1636, Q1643, Q1757, Q1761, Q1764	1.79
SCE	Sanborn Hybrid 3	8342	Customer Action	Q1632	1.62
SCE	South of Vincent Centralized Remedial Action Schemes	8483	Material	Q1779, Q1782, Q1784, Q1791	1.30
PG&E	Convert Midway Substation 230 kV Bus D to BAAH	T.0001650	Material	Q1949	1.15
PG&E	Borden-Gregg 230 kV Lines #1 & #2	T.0007056	Land Rights	Q1129, Q1135, Q1158, Q1713	0.93

Table 29: Delayed Transmission Projects with Highest Delayed or At Risk Dependent Generation (GW)					
IOU	**Transmission Project Name**	**Delayed Transmission Project ID**	**In-Service Date Change Reason**	**Delayed or At Risk Resource Queue numbers**	**Delayed or At Risk Generation (GW)**
PG&E	Padre Flat-Panoche 230 kV Line #1	T.0003792	Land Rights	Q1129, Q1135, Q1158	0.90
PG&E	QC8RAS-08 Gates 500/230 kV Transformer Banks 11 and 12	T.0003009	Bundling Dependencies	Q1135, Q1158	0.70
PG&E	Pole Line Switching Station - "aka New 230 kV switching station to loop Dos Amigos – Panoche # 3 230 kV"	T.0009177	Project Design	Q1129, Q1135, Q1713	0.63
PG&E	Dos Amigos-Panoche #3 230 kV	T.0004255	Land Rights	Q1129, Q1135, Q1713	0.63

Table 29: Delayed Transmission Projects with Highest Delayed or At Risk Dependent Generation (GW)
Data Source: PG&E and SCE 2024 SB 1174 Data Request (within their 2024 Draft RPS Procurement Plans)

Out of the 11 transmission projects listed in Table 29, six were delayed due to the top three delay reasons (Customer Action, Other, and Material) and are delaying (or putting at risk) a combined 8.26 GW of dependent resources. For SCE, 3.69 GW of resources are projected to be delayed behind reliability upgrades to the Lugo substation; but even more of SCE's delayed and At Risk resources (5 GW) are associated with Centralized Remedial Action Schemes (CRAS), especially Tehachapi CRAS projects which are causing 3.38 GW of resources to be delayed or at risk of being delayed. SCE has reported to the CPUC that they are currently implementing changes to improve their timelines and technical capabilities to implement CRAS schemes. Since CRAS help avoid some transmission buildout, it is important for SCE to continue to accelerate its ability to maximize the utility of CRAS but also speed up implementation.

Based on PG&E's data response, a single 1.15 GW generator (Darden Hybrid Solar, Q1949) is projected to be delayed due to material delivery issues from PG&E's suppliers, while 0.93 GW of PG&E resources are projected to be delayed behind multiple transmission projects that are having trouble obtaining new land rights to reroute lines. Anecdotal reports of material delays impacting other PG&E projects have been received by CPUC staff, however those projects may be captured elsewhere in data reporting with other causes of delays.

Transmission Project Delay Impacts on the IOUs' RPS Compliance

The IOUs provided some narrative context within their 2024 Draft RPS Procurement Plans as to how transmission delays have or have not had an impact on their RPS compliance. All three IOUs report that transmission project delays will have no to minimal impact on their expected RPS compliance. These transmission delays may have an impact on the IOUs and other load serving entities ability to comply with the CPUC's Integrated Resource Planning procurement orders, but that question was not explored in the assessment but is being tracked in twice yearly reporting on Integrated Resource Planning (IRP) procurement compliance[118]. Below are further details as reported by the IOUs on the delay impacts on RPS compliance specifically.

PG&E

In its 2024 Draft RPS Procurement Plan, PG&E states that "over 90 percent of PG&E's forecasted RPS eligible generation is expected from projects that are already online and delivering to PG&E's bundled service customers. Given that most of the expected generation is from operating projects, PG&E's current project development status update has a minimal impact on PG&E's procurement decisions over the 10-year planning horizon."

SCE

Despite having transmission project delays, SCE does not expect these delays to impact its RPS requirements for RPS Compliance Periods 2025-2027 and 2028-2030. However, SCE specifically mentions four projects that could be impacted by transmission delays, including Overnight Solar, LLC, Atlas Solar V, LLC, Atlas Solar VI, LLC, and Atlas Solar X, LLC.

SDG&E

SDG&E notes in its 2024 Draft RPS Procurement Plan that it experienced no transmission project delays during the reporting period of January 1, 2019, to the time of its draft 2024 RPS Plan.

Mitigation Efforts for Transmission Project Delays

Within their 2024 Draft RPS Procurement Plans, the IOUs also described mitigation efforts and business process improvements from July 22, 2023, to July 22, 2024, which was the twelve months prior to the 2024 Draft RPS Procurement Plan due date, to address the most significant reasons for delays to transmission in-service dates. Additionally, the IOUs provided details on mitigation efforts and business process

118 See IRP Procurement Track information: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/more-information-on-authorizing-procurement/irp-procurement-track.

improvements to be undertaken by the transmission side of the utility over the next twelve months (July 22, 2024, to July 22, 2025) to address the most significant reasons for delays to transmission in-service dates.

Overall, the IOUs provide some insight into previous and future mitigation efforts for some of the common delay reasons discussed in the assessment, including Customer Action and Material-related delays. However, PG&E does not mention any specific mitigation efforts to address Land Rights, which is the delay reason for transmission projects tied to the most dependent generation and storage resources (2.7 GW). SCE does not provide any specific mitigation efforts to address transmission projects delayed for Other, which SCE subcategorized as Prioritization, Scope Change, and Third-Party Transmission Builder. Additionally, neither IOU addresses Utility Permitting, which has the longest median delay time for both IOUs.

PG&E

To address the most significant reasons for transmission project delays, PG&E points out three mitigation efforts implemented over the last 12 months. First, PG&E reallocated funds to transmission projects that were previously delayed due to capital and financial constraints. Second, PG&E expanded its approved material and equipment vendor list to address supply chain constraints. Lastly, PG&E considered projects with readily available materials and equipment that had schedule flexibility and that could be delayed with no to little impact, and how readily available materials could be reallocated to projects deemed at-risk. These mitigation efforts addressed some of the delay reasons for transmission projects identified as most significant by PG&E, including Financing and Materials.

No new specific mitigation efforts were identified by PG&E as being implemented over the 12 months following the 2024 Draft RPS Procurement Plan date. However, PG&E states that its previous initiative to identify supplies and place bulk orders of materials and equipment will continue. These mitigation efforts address Materials, which was identified by PG&E as a significant delay reason for transmission projects.

SCE

In 2022, SCE conducted a review of its generator interconnection process, including examining the generator interconnection study application submission process, construction start date, and project billing. The review led to several process improvements in 2023 and 2024.

To better track the interconnection process, SCE implemented a tracking dashboard that utilizes Power BI. SCE made improvements to its work order phase by removing the Emergent Project Evaluation Form as a step. A pilot program to evaluate this change demonstrated an average reduction in the work order phase by 34 percent (approximately 1.5 months). SCE also deployed its Grid Interconnection Processing Tool to intake interconnection requests and created a risk matrix for its customers.

SCE also identified that the Centralized Remedial Action Schemes (CRAS) component of its interconnection process, when needed, could potentially delay a project. To address this, SCE is expanding CRAS' technical capabilities and adding two new staff that will potentially shorten the CRAS timeline. This mitigation effort addresses some of the delay reasons for transmission projects identified as most significant by SCE, including customer action. Additionally, SCE has also been recommending that new delayed renewable energy and energy storage resources request a Limited Operation Study (LOS) through CAISO to determine the extent their generation may operate prior to the completion of applicable transmission upgrades. Over the 12 months prior to SCE's 2024 Draft RPS Procurement Plan, the CAISO and SCE have completed 13 LOS, allowing 2.4 GW of the requested 2.9 GW to be generated by the requested in-service dates.

SCE expects to continue exploring efficiencies in the project execution phase and CRAS processes, as well as continuing to suggest that new renewable energy and energy storage resources request LOS from the CAISO when applicable. SCE will also implement new procurement processes to address equipment delays via interconnection forecasting and factory capacity reservations. These mitigation efforts address Customer Action and Materials, which were identified by SCE as a significant delay reason for transmission projects.

SDG&E

SDG&E did not report any transmission delays, however, it stated that "SDG&E is continually documenting processes, lessons learned, benchmarking best practices, and working collaboratively to provide exceptional customer service and most accurate assessments for projects' implementations. Currently, there is no quantification of impacts from our continuous improvement processes."

SDG&E also stated that "SDG&E will continue its ongoing efforts to avoid impacts to in-service dates of renewable projects."

Future Reporting and Systemwide Assessments

Staff have noted various instances where future SB 1174-related data requests can be improved to allow for more uniform and comprehensive data from the IOUs. There are instances where instructions should be clarified, and key terms can be better defined. For example, the high prevalence of transmission project delays being attributed to "Customer Action" and "Other" indicate that these two delay reasons, and maybe others, should be redefined to more accurately describe the core reason(s) for each transmission project delay.

Additionally, staff will revisit important terms and concepts in the data request, such as "transmission and interconnection projects" and "original in-service date" to ensure that there is a mutual understanding and standardized reporting on this data and other identified terms between the IOUs. Staff interpreted "transmission and interconnection projects" based on SB 319 (McGuire, Chapter 390, Statues of 2023), which includes all in-progress transmission projects in each PTOs portfolio, including CAISO approved projects such as those found in CAISO's Transmission Development Forum (TDF). However, the data request for the assessment was less specific stating that "Electrical corporations shall list each of their transmission facility and system network upgrades that are currently in development". More specific instructions will be used in future assessments.

The "original in-service date" for each reported transmission project is defined in the data request as "the expected in-service start date when the project was first approved." However, the sources for these dates, such as the CAISO transmission planning process, are not specified. Future assessments will give examples of sources to use for "original" and "current" in-service dates.

In future assessments, staff will consider how to cross reference the transmission projects listed in each IOU's SB1174 data templates against those listed in the latest TDF data and TPR data. There is currently some uncertainty about the completeness of the information provided to staff by the IOUs, specifically in the case of SDG&E who reported no delayed transmission projects in its SB1174 data templates, but in the July 31, 2024 TDF reported six approved transmission projects in the permitting or design phase whose in-service dates have been pushed back.

Lastly, staff will consider any obstacles that the IOUs can experience when complying with the SB 1174 data request. Especially the requirement of comprehensive data on both transmission projects and generation and storage resources. This creates a unique challenge for IOUs that need to keep specific transmission and generation separate between the transmission development side and resource procurement side of their organizations, to prevent unfair market practices. Staff will consider this issue and develop ways to streamline future data requests. Lastly, CPUC staff will continue to coordinate with participating transmission owners to better identify causes of long and impactful transmission project delays.

Compliance and Enforcement

This chapter provides an overview of the RPS program's compliance and enforcement process. Each August, retail sellers are required to submit annual preliminary RPS Compliance Reports to the CPUC that contain historical and forecasted data on their renewable procurement. The CPUC uses these reports to conduct analysis of retail sellers' progress towards their RPS mandates and identify any compliance risks based on the information provided by retail sellers. The reports are necessary for the CPUC to quantify each retail seller's procurement and facilitate the CPUC's determination of the forecasted compliance status of each retail seller.

Specifically, compliance with the RPS program is measured in eligible Renewable Energy Credits (RECs)[119] and evaluated on a multi-year compliance basis. The CPUC works closely with the CEC to make formal compliance determinations, using the CEC's Procurement Verification Report[120] to confirm each retail seller's actual REC claims. The CEC utilizes reports from the Western Renewable Energy Generation Information System (WREGIS)[121] to determine the amount of renewable electricity generated by each RPS-eligible facility. The CEC analyzes the eligibility of the facility, the quantity of RECs created, and ensures each REC claimed by retail sellers is eligible for compliance and not double-counted. The CPUC reviews retail sellers' final RPS Compliance Reports and RPS contracts in conjunction with the CEC's Procurement Verification Report to determine compliance. These compliance determinations cannot take place until the CEC completes its verification process and the CPUC thereafter completes its compliance review. Additional details regarding RPS compliance and enforcement are in Appendix B of this report.

CPUC Compliance Determinations

To ensure electricity' retail sellers meet their RPS requirements, the CPUC is responsible for establishing enforcement procedures and imposing penalties for non-compliance with the RPS program. As noted above, requirements are based on multi-year compliance periods. Compliance is determined after a compliance period has been completed and the CEC has verified REC claims.

119 A REC is 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 represent a claim on the renewable attributes of one unit of energy (MWh) generated from a renewable resource. RECs are "created" by a renewable generator and its creation is simultaneous with the production of electricity. When an LSE decides to use RECs for compliance with the State's RPS program, it must be retired and cannot be used again.

120 See https://www.energy.ca.gov/programs-and-topics/programs/renewables-portfolio-standard/renewables-portfolio-standard-5 for the most recent RPS Verification Report issued by the CEC.

121 The Western Renewable Energy Generation Information System (WREGIS) is an independent renewable energy tracking system for the region covered by the Western Electricity Coordinating Council (WECC). All renewable generation in the WECC must be tracked through WREGIS and used for state RPS programs.

In 2017, the CPUC evaluated RPS-eligible procurement and made final compliance determinations for compliance period 2011–2013 and determined that six retail sellers were non-compliant with their RPS procurement obligations.[122]

In 2019, the CPUC made final compliance determinations for compliance period 2014–2016 and found that out of 26 retail sellers, 3 were non-compliant with their RPS procurement obligations. Two of these three retail sellers did not meet the long-term contracting requirement and, therefore, could not count their short-term procurement toward their procurement quantity requirement (PQR).[123] The third non-compliant retail seller did not procure enough RECs to meet its requirements.

In 2023, the CPUC made final compliance determinations for compliance period 2017-2020 and found of 41 retail sellers, 5 were non-compliant with their RPS obligations. One retail seller retired too few Portfolio Content Category (PCC) 1 RECs to meet their Portfolio Balance Requirement[124] and one was not able to claim RECs that were retired outside of the allowable 36-month post-generation period. The remaining three retail sellers were found out of compliance with RPS contract and reporting requirements due to one or more contracts missing required RPS non-modifiable standard terms and conditions.[125]

Enforcement

Compliance Period 2011-2013

In December 2017, the CPUC issued compliance determination letters to the 20 retail sellers operating in compliance period 2011–2013. Six entities failed to comply with either the long-term contracting requirement and/or the PQR. Four retail sellers accepted the CPUC's determination and paid their non-compliance penalties. Two retail sellers, Gexa Energy California and Liberty Power Holdings, filed for waivers of their respective RPS penalties under § 399.15 of the Public Utilities Code. In August 2019, the CPUC issued a decision denying the two retail sellers' requests for waiver of their penalties. These two retail sellers were required to pay a cumulative sum of over $2 million.[126] The total penalties collected for compliance period 2011–2013 were approximately $4.1 million which went to the state's General Fund.

Compliance Period 2014-2016

In October 2019, the CPUC issued compliance determination letters to the 26 retail sellers operating in compliance period 2014–2016. Three entities failed to comply with either the long-term contracting

122 The six retail sellers determined non-compliant for compliance period 2011-2013 include Commercial Energy of California, Commerce Energy (Just Energy Solutions), Direct Energy Business, Gexa Energy, Liberty Power Holdings, and Tiger Natural Gas.

123 See D.17-06-026 for more information on the RPS long-term contracting rules

124 Refer to D.11-12-052 and D.16-12-040 for complete rules governing the classification of RPS procurement.

125 Requirements for standard terms and conditions in RPS contracts can be found in D.08-04-009, D.11-01-025, and D.07-11-025

126 See D.19-08-007.

requirement and/or the PQR. One retail seller, Commercial Energy, accepted the compliance determination and timely paid their non-compliance penalty. One of the non-compliant retail sellers, Agera Energy, filed for Chapter 11 bankruptcy in October 2019 and neither filed a waiver request nor paid $392,230 penalty. Consequently, collection of Agera Energy's compliance period 2014-2016 penalties was contingent on Agera Energy's bankruptcy proceedings. In April 2023 and March 2024, Agera provided partial payments of $15,988.44 and $23,206.75, respectively, and the remaining amount is uncollectable. Gexa Energy California, again, filed for a waiver of their assessed RPS penalty of $3,704,675, and the CPUC adjudicated their waiver request resulting in a revised penalty of $352,500. The total penalties collected for compliance period 2014–2016 were $526,223.44. These penalties were deposited in the Electric Program Investment Charge Fund reducing ratepayers' investment costs in scientific and technological research to meet the state's energy and climate goals.[127]

Compliance Period 2017-2020

In April 2023, the CPUC issued compliance determination letters to the 42 retail sellers serving load in compliance period 2017-2020. One retail seller failed to comply with the Portfolio Balance Requirement and four retail sellers failed to comply with the PQR due to RECs found ineligible. The two retail sellers who reported RPS deficiencies, Liberty Utilities and EDF Industrial Power Services, accepted their compliance determinations and timely paid their non-compliance penalties. The remaining three retail sellers, CleanPower SF, Direct Energy Business, and Pilot Power Group, all procured sufficient RECs to satisfy RPS requirements, but each had RECs disqualified due to their respective contracts missing CPUC's RPS non-modifiable standard terms and conditions. All three retail sellers filed motions to waive the assessed penalties. The CPUC adjudicated their waiver requests, finding that each of the three retail sellers fulfilled their RPS procurement requirements, but failed to fully comply with RPS contract and reporting requirements, resulting in a revised penalty of $500 each. Total penalties collected from noncompliance in the 2017-2020 compliance period amounted to $1,238,930. Citations pursuant to the waiver motions total $1,500 to be paid by November 16, 2024. As in the prior compliance period, these penalties and citations are deposited in the Electric Program Investment Charge Fund to reduce ratepayers' investment costs.

127 Per Public Utilities Code § 399.15(b)(8), the penalties collected for the RPS program are deposited into the Electric Program Investment Charge (EPIC) fund.

RPS Workforce Development and Diversity

This chapter describes RPS workforce development activities of the Investor-Owned Utilities (IOUs), Small and Multi-Jurisdictional Utilities (SMJUs), Community Choice Aggregators (CCAs), and some of the Electric Service Providers (ESPs), consistent with Public Utilities Code 913.4(f).[128] The state requires collection of this information to ensure an adequately trained and available workforce that can support California's increasing dependence on advanced renewable energy technologies. The sections below provide data and trends on workforce development related to retail sellers' current RPS workforce, diversity of staff, strategies used to proactively recruit and train their staff to support California's ambitious goals for reliable, clean energy. To provide this overview, the CPUC collected information on workforce development data directly from the IOUs, SMJUs, CCAs, and ESPs.

IOU Workforce Development

The IOUs report a significant focus on offering equal employment opportunities with respect to the recruitment, hiring, and professional development practices associated with the implementation of the RPS program.

Current IOU RPS Workforce

Table 30 and Figure 18 provide an overview of the number of full-time PG&E, SCE, and SDG&E employees who worked on RPS-related issues from 2015 – 2024. In total, the three IOUs reported a cumulative increase in total employees working on RPS issues from 228 to 381 in the past year.

Table 30: Total RPS Employees at Investor-Owned Utilities (2015-2024)										
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Totals	206	161	169	135	302	271	307	172	228	381

Table 30: Total RPS Employees at Investor-Owned Utilities (2015-2024)
Data Source: PG&E, SCE, SDG&E, September 2024

Figure 18 illustrates how the number of RPS employees for the three IOUs has changed over the past ten years.[129]

128 Public Utilities Code § 913.4(f) applies to retail sellers and the reporting in this chapter does not reflect the workforce development and diversity efforts of renewables project developers.
129 This time series data is current as of August 2024 and includes employment data from January 2014 through July 2024.

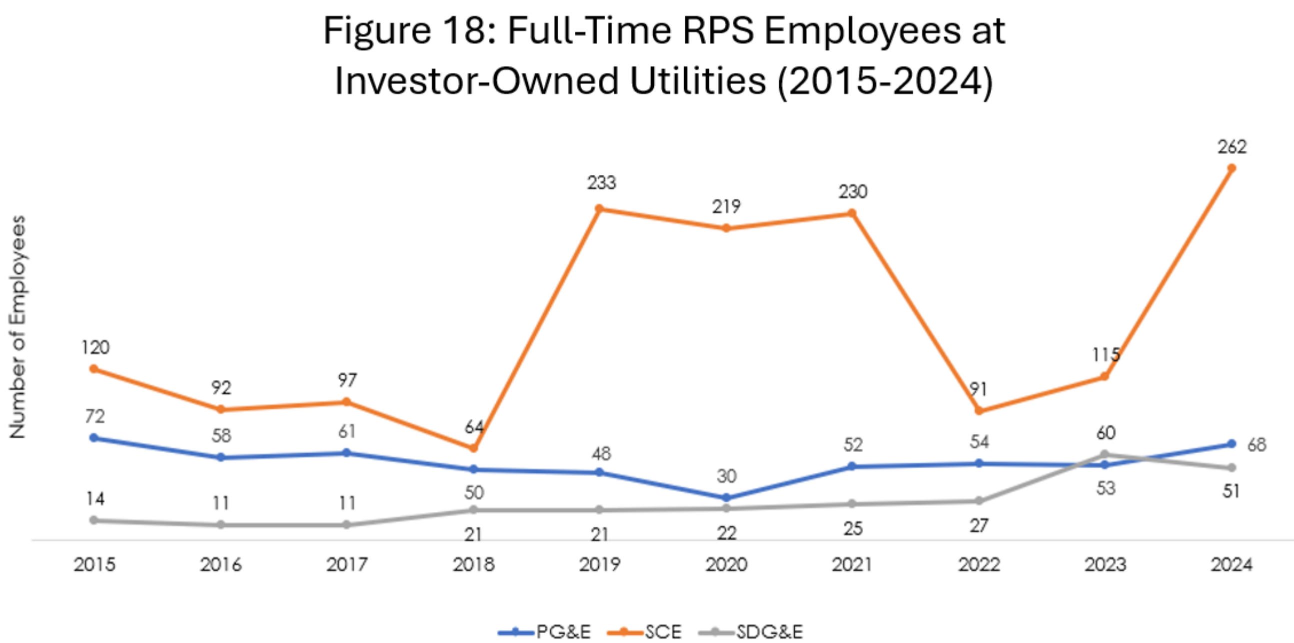

Figure 18: Full-Time RPS Employees at Investor-Owned Utilities (2015-2024)
Data Source: PG&E, SCE, SDG&E, August 2024

Current IOU RPS Workforce Diversity

Each of the IOUs reported having company-wide diversity goals to build a workforce that reflects the diversity of the State of California. Common diversity efforts across the IOUs include providing equal employment opportunities in all aspects of their employment practices and hiring more women, minorities, and disabled veterans to implement the RPS program. In 2024, all three of the IOUs reported working with organizations that focus on professional development for women, minorities, and disabled veterans.[130]

Figure 19 illustrates aggregated data on the percentage of women, minorities, and disabled veterans who are full-time employees who work on the RPS program at the three IOUs.

130 General Order 156 refers to the rules governing the development of programs to increase participation of women, minority, disabled veterans, and LGBT business enterprises in procurement contracts from IOUs as required by Public Utilities Code §§ 8281-8286. The IOUs are compliant with General Order 156 requirements on Supplier Diversity. https://www.cpuc.ca.gov/supplierdiversity/.

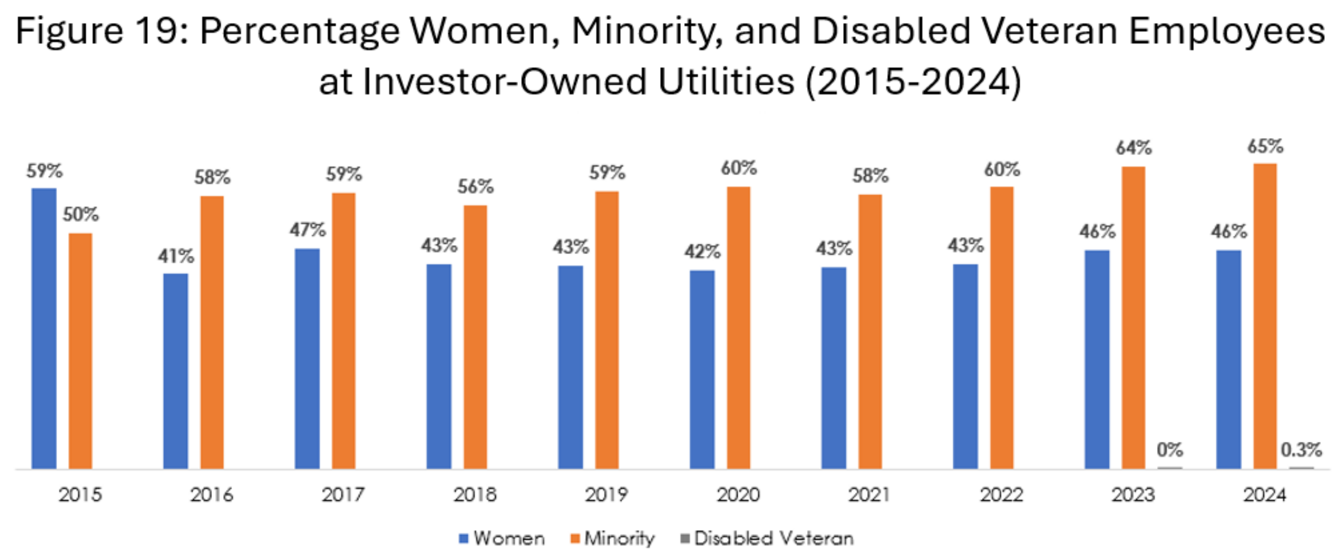

Figure 19: Percentage Women, Minority, and Disabled Veteran Employees at Investor-Owned Utilities (2015-2024)
Data Source: PG&E, SCE, SDG&E, August 2024

PG&E

Table 31 shows the percentages of PG&E's RPS employees who are women, minorities, and disabled veterans compared with total PG&E RPS staff. In 2024, PG&E's RPS staff was comprised of 43 percent women and 63 percent minority staff members. Both percentages increased over the past year. The percentage of women in PG&E's RPS workforce is 17 percentage points higher than the national average for women in the energy workforce.[131]

Table 31: PG&E's Percentage of Women, Minority, and Disabled Veteran RPS Employees[132] from 2015–2024

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Women	50%	22%	44%	43%	42%	35%	21%	35%	38%	43%
Minority	44%	48%	48%	47%	55%	60%	33%	52%	57%	63%
Veterans	3%	3%	0%	4%	n/a	n/a	n/a	n/a	n/a	0%
Total RPS Staff	72	58	61	50	48	30	52	54	53	68

Table 31: PG&E's Percentage of Women, Minority, and Disabled Veteran RPS Employees from 2015–2024
Data Source: PG&E, September 2024

131 Data source: Department of Energy (DOE) Energy and Employment Report, 2024.
132 Under the tables in this section of the Report, RPS Employee demographic percentages classified as "n/a" signify that the retail seller did not collect data on this demographic type for that annual report cycle. On the other hand, a "0%" signifies that the retail seller collected data on the demographic type, but that there were no employees to report under it.

Data on the ethnic and racial backgrounds of PG&E RPS employees for 2020-2024 is displayed below in Table 32.

Table 32: PG&E's Ethnic and Racial Background of RPS Employees from 2020–2024						
	RPS Employees					Energy Workforce Average [133]
	2020	2021	2022	2023	2024	2024
American Indian or Alaskan Native	0%	0%	0%	0%	0%	2%
Asian	47%	35%	37%	39%	46%	7%
Black/African American	0%	0%	2%	2%	0%	9%
Hispanic/ Latino	10%	12%	11%	13%	13%	18%
Native Hawaiian or Pacific Islander	0%	0%	0%	0%	0%	1%
Two or more races	3%	3%	2%	4%	3%	5%
White	40%	50%	48%	43%	37%	74%
Other	0%	0%	0%	0%	1%	2%

Table 32: PG&E's Ethnic and Racial Background of RPS Employees from 2020–2024
Data Source: PG&E, September 2024, DOE Energy and Employment Report, 2024

SCE

Table 33 illustrates the percentage of SCE's RPS employees who are women, minorities, or disabled veterans. The percentage of women in SCE's RPS workforce is 20 percentage points higher than the national average for women in the energy workforce.[134]

133 The DOE Energy and Employment Report draws from various Census datasets, which identify Hispanic/Latino as an ethnic group rather than a racial group, as people of Hispanic origin may be of any race(s) (Source: US Census Bureau). This means that the Hispanic/Latino ethnic group should be separated when summing the percentages of the other racial identities in this table.

134 Data source: Department of Energy (DOE) Energy and Employment Report, 2024.

Table 33: SCE's Percentage of Women, Minority, and Disabled Veteran RPS Employees from 2020–2024					
	RPS Employees				
	2020	**2021**	**2022**	**2023**	**2024**
Women	43%	44%	46%	48%	46%
Minority	60%	60%	63%	68%	68%
Disabled Veterans	No Data	No Data	No Data	<1%	0%
Total RPS Staff	219	230	91[135]	115	262

Table 33: SCE's Percentage of Women, Minority, and Disabled Veteran RPS Employees from 2020–2024
Data Source: SCE, September 2024

The ethnic and racial backgrounds of SCE's RPS employees are displayed below.

Table 34: SCE's Ethnic and Racial Background of RPS Employees from 2020–2024						
	RPS Employees					Energy Workforce Average
	2020	**2021**	**2022**	**2023**	**2024**	**2024**
American Indian or Alaskan Native	0%	0%	0%	0%	0%	2%
Asian	33%	33%	32%	36%	34%	7%
Black/African American	6%	6%	5%	6%	6%	9%
Hispanic/Latino	18%	17%	21%	20%	24%	18%
Native Hawaiian or Pacific Islander	1%	1%	0%	0%	0%	1%
Two or more races	3%	3%	4%	5%	5%	5%
White	40%	40%	37%	32%	32%	74%
Other	0%	0%	0%	0%	0%	2%

Table 34: SCE's Ethnic and Racial Background of RPS Employees from 2020–2024
Data Source: SCE, September 2024

135 SCE reported the total number of RPS staff for years 2022 and 2023 based on the percentage of time employees spend working on RPS issues (a range of 0 to 100 percent).

SDG&E

Table 35 illustrates the number of SDG&E's RPS employees who are women, minorities, or disabled veterans. In 2024, SDG&E's RPS staff was comprised of 51 percent women and 49 percent minority staff members. The percentage of women in SDG&E's RPS workforce is 25 percentage points higher than the national average for women in the energy workforce.[136]

Table 35: SDG&E's Percentage of Women, Minority, and Disabled Veterans RPS Employees from 2020–2024					
	RPS Employees				
	2020	2021	2022	2023	2024
Women	45%	44%	41%	48%	51%
Minority	45%	48%	48%	53%	49%
Disabled Veterans	0%	0%	0%	0%	2%
Total RPS Staff	22	25	27	60	51

Table 35: SDG&E's Percentage of Women, Minority, and Disabled Veterans RPS Employees
Data Source: SDG&E, September 2024

The ethnic and racial background of SDG&E's RPS employees is shown below.

Table 36: SDG&E's Ethnic and Racial Background of RPS Employees from 2020–2024						
	RPS Employees (Full-Time)					Energy Workforce Average
	2020	2021	2022	2023	2024[137]	2024
American Indian or Alaskan Native	0%	0%	0%	0%	0%	2%
Asian	5%	8%	11%	17%	18%	7%
Black/African American	14%	8%	7%	8%	6%	9%
Hispanic/Latino	32%	32%	26%	15%	12%	18%

136 Data source: Department of Energy (DOE) Energy and Employment Report, 2024.
137 The total count of SDG&E's ethnic and racial background of RPS employees excludes 2 staff who declined to state their race/ethnicity.

Table 36: SDG&E's Ethnic and Racial Background of RPS Employees from 2020–2024						
	RPS Employees (Full-Time)					Energy Workforce Average
	2020	**2021**	**2022**	**2023**	**2024**[137]	**2024**
Native Hawaiian or Pacific Islander	0%	0%	0%	2%	0%	1%
Two or more races	5%	0%	4%	12%	14%	5%
White	45%	52%	52%	47%	49%	74%
Other	0%	0%	0%	0%	0%	2%

Table 36: SDG&E's Ethnic and Racial Background of RPS Employees from 2020–2024
Data Source: SDG&E, September 2024

Recruiting Strategies

Recruiting efforts at each of the IOUs tend to utilize both broad candidate outreach and targeted strategies to recruit diverse candidates. In addition, the utilities also offer programs that can act as training and recruitment of future employees, including long-term efforts within California's school systems.

PG&E

Recruitment Marketing, Social Media, Recruitment Tools and Resources

PG&E does not have specific hiring goals for the RPS program; however, PG&E's Diversity, Equity, Inclusion, and Belonging (DEIB) and Talent Acquisition (TA) teams align with the Office of Federal Contract Compliance Programs (OFCCP) for affirmative action plans to ensure a diverse workforce to achieve equal employment opportunity. All open positions, where PG&E is hiring external candidates, are shared with the following organizations and entities: Cal Jobs + local Veteran employment reps, DiversityJobs.com (which include Women, Veterans, LGBTQIA, AAPI, Native & Indigenous People, Hispanic/LatinX, African American/Black, Individuals with Disabilities (IWD), Older Workers sites), LinkedIn, Job boards through Radancy's Programmatic Job AI (including Indeed, ZipRecruiter, Dice), Center for Energy Workforce Development (CEWD). Additionally, for positions with an affirmative action plan goal for women or minorities, PG&E posts with the following local organizations: Sacramento Hispanic Chamber of Commerce, Sacramento LGBT Community Center, Folsom Cordova Job Center, Rubicon Programs, SF Women Center, Oakland LGBTW Community Center, Upwardly Global, Concord Chamber of Commerce, Fresno Metro Black Chamber of Commerce.

Diverse Employee Recruitment

To ensure inclusivity and a diverse workforce, PG&E communicates open positions, dependent on job type, with the following free and paid job boards: Navy Bases (TAP), California Women in Energy, Energy Folks, Women in Trade (Tradeswomen), Utility Arborist Association, California Conservation Corps, California Licensed Foresters Association, Traverse Jobs, Society of Women Engineers, Society of Hispanic Professional Engineers, National Society of Black Engineers, Institute of Electric and Electronic Engineers, Institute of Industrial & Systems Engineers, American Gas Association, American Planning Association, American Society of Civil Engineers, American Society for Quality, American Society of Safety Professionals, The Hill. Additionally, PG&E established a partnership with VetJobs, whereby a dedicated recruiter connects transitioning service members, as well as veterans and spouses to positions with PG&E. And lastly, PG&E attends a number of career fairs throughout the year focusing on outreach to Veterans and individuals with disabilities.

SCE

Recruitment

SCE's recruitment outreach generally includes the following categories:

- Recruitment Marketing, Social Media, Recruitment Tools and Resources
- Professional and Community Association Outreach
- Military Veteran Outreach
- Individuals with Disabilities Outreach
- University & Campus Relations
- Internal Business Resource Group (BRG) Partnerships
- Lineworker Scholarship Program

Recruitment Marketing, Social Media, Recruitment Tools and Resources

SCE's career site includes targeted pages focusing on women, individuals with disabilities, military veterans, diversity & inclusion, early career, and critical positions like data scientist, cybersecurity, continuous improvement, environmental policy, planning, skilled trades, engineering, and IT. Their career site is also fully mobile and accessible to individuals with disabilities. Visitors on the site and other channels are invited to join the SCE Talent Network that allows active and future job seekers to stay connected and updated on company news, events and job opportunities.

SCE also shares and promotes jobs and content on major social and job sites such as LinkedIn, Glassdoor, and Indeed for maximum visibility. Content developed and shared across SCE's major channels is focused on company initiatives, storytelling and featuring employees across the organization with different backgrounds. To help the job opportunities and content reach particular demographics, they use targeted paid advertisements through LinkedIn, Facebook, Indeed, Glassdoor, and Instagram.

To assist with meeting federal contractor job posting requirements, SCE has a partnership with Direct Employers to promote their jobs. To help with female recruitment outreach, SCE has been a member of Fairygodboss, the largest career community for women. SCE uses SFX, a talent marketing platform that combines CRM, career site, and programmatic advertising. SFX helps with automating our high-volume tasks and allows the company to connect with candidates at any time. SFX can also help with measuring the return on their recruitment marketing expenses.

The augmented writing platform, Textio, is used by recruiters and hiring leaders to help SCE with writing inclusive and compelling job descriptions.

Professional and Community Association Outreach

SCE employees are active and continue to partner with several professional and community groups.

Their participation includes attending their career related events, being on-podium (keynote) at their annual conferences and mentoring their early-career members. Some of the professional and community associations include the following:

- Society of Women Engineers (SWE)
- Society of Hispanic Professional Engineers (SHPE)
- National Society of Black Engineers (NSBE)
- Asian American Professional Association (AAPA)
- American Association of Blacks in Energy (AABE)
- Native American Tribes, specifically the 13 tribes within the SCE service territory
- Disability:IN
- New Horizons
- Trans Can Work
- Foundation for Women Warriors
- LA LGBT Center
- Paradigm for Parity Coalition
- Catalyst
- Direct Employers
- Association of Women in Water, Energy and Environment (AWWEE)
- OUTLeadership

Additionally, SCE has 12 Business Resource Groups which are actively involved with many community organizations and have formed lasting relationships with members of these organizations to advance diversity, equity, and inclusion throughout their service territory.

Military Veteran Outreach

SCE states that it is committed to hiring and supporting military veterans. Some of its recruitment outreach and strategies to the veteran communities include the following:

- Hosting company information sessions for active military and veterans.
- Maintaining a military/veteran page on their career site which includes a military translator tool through Recruit Rooster. The translator tool allows job seekers to identify which careers at SCE are a good match with their military background.
- Leveraging VALOR, SCE's veteran Business Resource Group, to help the company engage and stay connected with the veteran community.

Individuals with Disabilities

SCE is a member of the U.S. business leadership network, Disability:IN, which is the leading nonprofit resource for business disability inclusion worldwide. Employees from various parts of the company are active members of this network and attend their annual conference to remain current on how companies can best attract and retain individuals with disabilities and strengthen their inclusive culture. In addition, SCE employees continue to conduct information sessions at non-profits such as the Salvation Army Rehabilitation facility to provide participants with insight into career paths at SCE. They partnered with Springboard Consulting to host a cross-company conversation on recruitment, retention, compliance, and accessibility best practices through "Leaders 4Disability" to identify areas of focus in their disability inclusion initiatives.

University & Campus Relations

SCE's college recruitment efforts are generally targeted at students pursuing degrees in engineering, accounting, finance, information technology, and cyber security at mostly California-based universities and colleges. The company also developed a leadership development program for MBA graduates from select schools.

In addition, SCE partners with organizations such as TELACU, GMiS (Great Minds in STEM), and MESA (Mathematics Engineering Science Achievement) to help with attracting a diverse group of early career talent.

SCE promotes all early-career job opportunities at most Historically Black Colleges and Universities (HBCU) through Handshake. Handshake is a recognized platform for college students and alumni to find job opportunities. In addition, SCE currently has strategic relationships with two HBCUs, which includes virtual recruiting activities and outreach, such as company information sessions.

Since 2017, SCE has worked with Cal Poly Pomona's Open University to help prepare students for careers in utility planning. Several instructors for Cal Poly Pomona's Energy Planner Certification are SCE employees.

As part of its Lineworker Scholarship Program, Edison International developed a four-year, $1-million pilot scholarship program in 2021 to provide scholarships and additional support totaling up to $25,000 per recipient. The purpose of this scholarship program is to expand the pool of Lineworker scholarship applicants through the provision of scholarships and additional support totaling up to $25,000 per recipient. Each annual cohort consists of twelve scholarship recipients, who enroll in an applicable program at Los

Angeles Trade Tech College (LATTC). The program's focus is to expand representation in the skilled trade profession. SCE has since hired nine graduates from Lineworker Scholarship Cohort 1, five graduates from Cohort 2, and 3 graduates from Cohort 3. Twelve scholars were selected for Cohort 4 and will begin prerequisite classes at LATTC in the fall.

Company Business Resource Group Partnerships

SCE's Talent Acquisition partners with the company BRGs on outreach activities, specifically on job preparation strategies. Some examples include the following:

- Through the Networkers BRG, the Black Male Initiative was formed to partner with community, spiritual and non-profit organizations to help promote SCE job opportunities and career paths to members of their organizations.
- In partnership with the Business Resource Group, Latinos Engagement Advancement and Development (LEAD), Talent Acquisition presented to Latino student and community groups on resume writing best practices and interview preparation.
- SCE employees worked with the Native American Alliance Business Resource Group and representatives from other companies to host a virtual career expo to the members of the 13 tribes within SCE's service territory. Attendees were able to hear about job opportunities and practical advice about how to best prepare for their next job.

Training

Energy Procurement and Management (EPM) has implemented several continuous improvement initiatives focused on creating employee development and training programs. Internal training opportunities cover topics such as SCE's renewable procurement programs, including large-scale RPS solicitations and small-scale RPS procurement programs (e.g., feed-in tariffs, Renewable Auction Mechanism (RAM), etc.). These training sessions range from subject matter-specific to more general overviews using a wide-range of forums comprising of formal cross-training options, webinars, bidders conferences, RPS pro forma technical review sessions (when contracting for such resources), and more informal methods such as brown bag sessions, overview trainings, regulatory updates, lessons learned meetings, and RPS solicitation kick-off meetings (when soliciting for such resources).

SDG&E

General Outreach

SDG&E has a stated commitment to diversity and inclusion. Their recruiting program includes posting job opportunities on various job boards such as Association of Women in Water, Energy and Environmental (AWWEE), Black Career Women's Network, MANA de San Diego, Women in Clean Tech & Sustainability (WCTS), NativeHire.org, Work for Warriors, Pink Jobs, CA Minority Council, San Diego Equality Business Association and Women of Renewable Industries and Sustainable Energy (WRISE), and also utilizes social media outlets such as LinkedIn, Instagram, Facebook and YouTube to provide company information and advertise openings.

Diverse Employee Recruitment

As part of its recruiting program, SDG&E partners with diverse organizations including American Association of Blacks in Energy (AABE), American Indian Science and Engineering Society (AISES), National Association of Women in Construction (NAWIC), Asian Business Association (ABA), The Honor Foundation, National Society of Black Engineers (NSBE), San Diego Committee on Employment for People with disABILITIES, Society of Women Engineers (SWE), and Women in Technology International (WITI). SDG&E's recruitment staff also focus on military outreach and work with organizations such Employment Development Department (EDD), Hire GI, and Recruit Military, and support programs such as San Diego's Competitive Edge, and the San Diego Workforce Partnership's (SDWP) Career Jumpstart.

SDG&E's partnership includes providing funding, attending events and hiring participants, posting job opportunities on their websites, helping them to expand their membership and collaborating with them on events by facilitating workshops and serving as panels.

University Outreach

Candidates for SDG&E internship and associate rotation programs are recruited from several schools in California, as well as Historically Black Colleges and Universities across the country such as Howard University, Norfolk State University, and Prairie View A&M. These schools are chosen due to their academic excellence and focused disciplines, such as offering Electrical Engineer power programs.

SDG&E has structured internship and rotation programs for engineering, accounting & finance, and information technology. Each program rotates employees through a series of company departments as development opportunities and exposure to various parts of the organization. Additionally, programs include the following components:

- Mentoring by management and director level leaders
- Work experience, field trips, lunch & learns, and social activities
- Participation by school professors
- University Advisory Board membership by many leaders to influence curriculum
- Program management by leadership, typically directors, to monitor development
- Maintaining relationships with diverse student organizations, such as Mathematics Engineering Science Achievement (MESA), National Association of Black Accountants (NABA), Society of Asian Scientists and Engineers (SASE), Society of Hispanic Professional Engineers (SHPE), Association of Latino Professionals of America (ALPFA), etc.

SMJU Workforce Development

In Table 37, the three SMJUs' (Bear Valley [BVES], Liberty, PacifiCorp) report having a limited number of RPS staff.

Current SMJU RPS Workforce

Table 37: Total RPS Employees at SMJUs from 2020–2024					
	2020	**2021**	**2022**	**2023**	**2024**
BVES	3	3	3	3	3
Liberty	12	12	9	No Data	No Data
PacifiCorp	No Data	No Data	No Data	No Data	4

Table 37: Total RPS Employees at SMJUs from 2020–2024
Data Source: BVES & PacifiCorp, September 2024

Current SMJU RPS Workforce Diversity

Within the limited RPS staff, PacifiCorp was the only SMJU to report that its staff is comprised of women and minorities and none of them reported any disabled veterans as RPS staff.

Given the smaller size of their RPS staff, they have fewer resources dedicated to RPS workforce development compared to the IOUs.

Bear Valley Electric Service

The ethnic and racial background of BVES' RPS employees is shown in the table below.

Table 38: Bear Valley Electric Service's Ethnic and Racial Background of RPS Employees from 2020–2024						
	RPS Employees (Full-Time)					**Energy Industry Workforce Average**
	2020	**2021**	**2022**	**2023**	**2024**	**2024**
American Indian or Alaskan Native	0%	0%	0%	0%	0%	2%
Asian	33%	33%	33%	0%	0%	7%
Black/African	0%	0%	0%	0%	0%	9%

Table 38: Bear Valley Electric Service's Ethnic and Racial Background of RPS Employees from 2020–2024						
	RPS Employees (Full-Time)					Energy Industry Workforce Average
	2020	2021	2022	2023	2024	2024
American						
Hispanic/Latino	0%	0%	0%	0%	0%	18%
Native Hawaiian or Pacific Islander	0%	0%	0%	0%	0%	1%
Two or more races	0%	0%	0%	0%	0%	5%
White	67%	67%	67%	100%	100%	74%
Other	0%	0%	0%	0%	0%	2%

Table 38: Bear Valley Electric Service's Ethnic and Racial Background of RPS Employees
Data Source: BVES, September 2024

BVES has a supplier diversity program to measure organizational diversity and inclusion. BVES has not engaged in college recruitment efforts or offered scholarships to students within its service territory. The utility does not conduct internal training courses, but RPS employees are encouraged to attend training and workshops elsewhere in the State.

Liberty Utilities

The ethnic and racial backgrounds of Liberty Utilities' RPS employees are provided in the following table. Energy Division has not received Workforce Development data from Liberty in the past two years.

Table 39: Liberty Utilities' Ethnic and Racial Background of RPS Employees from 2020–2024					
	RPS Employees (Full-Time)				
	2020	2021	2022	2023	2024
American Indian or Alaskan Native	0%	0%	0%	No Data	No Data
Asian	8%	17%	22%	No Data	No Data
Black/African American	17%	8%	11%	No Data	No Data
Hispanic/Latino	0%	8%	11%	No Data	No Data

Table 39: Liberty Utilities' Ethnic and Racial Background of RPS Employees from 2020–2024					
	RPS Employees (Full-Time)				
	2020	2021	2022	2023	2024
Native Hawaiian or Pacific Islander	0%	0%	0%	No Data	No Data
Two or more races	0%	0%	0%	No Data	No Data
White	75%	67%	56%	No Data	No Data
Other	0%	0%	0%	No Data	No Data

Table 39: Liberty Utilities' Ethnic and Racial Background of RPS Employees from 2020–2024
Data Source: Liberty Utilities, September 2024

Liberty Utilities formed a Diversity and Inclusion Council in early 2019 comprised of representatives from all its regions and intended to set up the framework and activities to enable inclusion across the company. In addition, Liberty Utilities conducted an all-employee Diversity and Inclusion training in 2022. Liberty states that it is an equal opportunity employer and is committed to ensuring an equal and diverse workforce to implement the RPS program.

Liberty also offers seven scholarships to graduating high school students within the service territory and offers one annual community college scholarship.

PacifiCorp

PacifiCorp currently employs a small number of individuals to work on RPS issues for all states, with assistance from additional staff in environmental policy, regulation, and legal work on RPS-related matters, but their time is not tracked by issue or state.

The ethnic and racial backgrounds of PacifiCorp's RPS employees are shown below.

Table 40: PacifiCorp's Ethnic and Racial Background of RPS Employees from in 2024		
	RPS Employees (Full-Time)	Energy Workforce Average
	2024	2024
American Indian or Alaskan Native	0%	2%
Asian	25%	7%

Table 40: PacifiCorp's Ethnic and Racial Background of RPS Employees from in 2024		
	RPS Employees (Full-Time)	**Energy Workforce Average**
	2024	**2024**
Black/African American	0%	9%
Hispanic/Latino	0%	18%
Native Hawaiian or Pacific Islander	0%	1%
Two or more races	0%	5%
White	75%	74%
Other	0%	2%

Table 40: PacifiCorp's Ethnic and Racial Background of RPS Employees from in 2024
Data Source: PacifiCorp, September 2024

PacifiCorp has policies to support diversity and inclusion, including a diversity, equity and inclusion task force, but these are corporate-wide, and PacifiCorp does not implement workforce development programs related to recruitment, training, and retention of women, minority, and/or disabled veteran employees specific to California's RPS program.

Community Choice Aggregator (CCA) Workforce Development

Current CCA RPS Workforce

Table 41 shows the total full-time RPS employees at each CCA in response to the CPUC's data request.[138]

Table 41: Total Number of CCA RPS Employees from 2020 – 2024					
	2020	**2021**	**2022**	**2023**	**2024**
Apple Valley Choice Energy	2	0	2	0	8
Ava Community	2	No Data	2	3	8

138 The CCAs have varying interpretations of the data request categories and, therefore, reported RPS employees may not be directly comparable across the CCAs and the IOUs.

Table 41: Total Number of CCA RPS Employees from 2020 – 2024					
	2020	2021	2022	2023	2024
Energy					
Central Coast Community Energy	5	No Data	5	8	No Data
City of Commerce	No Data	No Data	No Data	0	No Data
City of Palmdale	No Data	No Data	No Data	1	4
City of Pomona	0	0	1	1	5
City of Santa Barbara	-	No Data	No Data	2	7
Clean Energy Alliance	-	No Data	1	1	1
Clean Power Alliance	6	7	8	No Data	10
CleanPowerSF	11	11	11	13	15
Desert Community Energy	-	No Data	3	4	4
King City Community Power	3	3	No Data	0	2
Lancaster Choice Energy	1	2	2	3	12
Marin Clean Energy	72	72	86	106	105
Orange County Power Authority	-	No Data	No Data	No Data	1
Peninsula Clean Energy	4	No Data	5	8	9
Pico Rivera Innovative Municipal Energy	0	0	2	0	8
Pioneer Community Energy	No Data	No Data	3	3	2
Rancho Mirage Energy Authority	1	1	1	1	7

Table 41: Total Number of CCA RPS Employees from 2020 – 2024					
	2020	**2021**	**2022**	**2023**	**2024**
Redwood Coast Energy Authority	8	8	10	5	33
San Diego Community Power	-	6	6	8	10
San Jacinto Power	0	0	0	0	3
San Jose Clean Energy	12	No Data	12	17	No Data
San Joaquin Valley Clean Energy Organization	-	-	-	-	No Data
Silicon Valley Clean Energy	2	No Data	10	12	18
Sonoma Clean Power Authority	9	No Data	11	9	11
Solana Energy Alliance	-	-	-	-	No Data
Valley Clean Energy Alliance	2	2	2	1	1

Table 41: Total Number of CCA RPS Employees from 2020 – 2024
Data Source: CCAs, September 2024

Current CCA RPS Workforce Diversity

In 2024, the CCAs reported engaging in business and workforce initiatives due to increased RPS operations. Table 42 illustrates aggregated data on the percentage of women, minorities, and disabled veterans who are full time employees at the CCAs who work on the RPS program. The average percentage of women across the CCAs' RPS workforce is 30 percentage points higher than the national average for women in the energy workforce.[139]

139 Data source: Department of Energy (DOE) Energy and Employment Report, 2024.

Table 42: Percentage of Women, Minority, and Disabled Veterans RPS Employees from 2020 – 2024 (Community Choice Aggregators)					
	2020	**2021**	**2022**	**2023**	**2024**
Women	56%	58%	54%	50%	56%
Minority	29%	33%	43%	36%	49%
Disabled Veterans	No Data	No Data	0%	0%	0%

Table 42: Percentage of Women, Minority, and Disabled Veterans RPS Employees from 2020 – 2024 (Community Choice Aggregators)
Data Source: CCAs, September 2024

The ethnic and racial backgrounds of the CCAs' RPS employees are shown in Table 43 below.

Table 43: Ethnic and Racial Background of CCA RPS Employees from 2023-2024			
	RPS Employees		**Energy Workforce Average**
	2023	**2024**[140]	**2024**
American Indian or Alaskan Native	1%	<1%	2%
Asian	15%	17%	7%
Black/African American	7%	7%	9%
Hispanic/Latino	13%	16%	18%
Native Hawaiian or Pacific Islander	2%	2%	1%
Two or more races	5%	6%	5%
White	45%	51%	74%
Other	12%	<1%	2%

Table 43: Ethnic and Racial Background of CCA RPS Employees from 2023-2024
Data Source: CCAs, September 2024

140 The total count of the CCAs' ethnic and racial background of RPS employees excludes 18 staff who declined to state their race/ethnicity.

The CPUC requested data from all CCAs. The CCAs generally report that they implement workforce development and diversity policies to build a workforce that promotes economic sustainability and inclusion in the renewable energy sector. Six CCAs reported that they engaged in employee recruitment through diversity-focused job boards, and 13 CCAs reported employee recruitment activity through general job boards. Seven CCAs reported that they engaged in outreach and made partnerships with professional and community associations. Seven CCAs reported on relations with universities and campuses, and six CCAs reported that they had made investments in employee training programs. Two CCAs noted partnerships with business resource groups.

ESP Workforce Development

Current ESP RPS Workforce

Table 44 shows the total full-time RPS employees at each ESP in response to the CPUC's data request.[141]

Table 44: Total Number of ESP RPS Employees from 2020 – 2024

	2020	2021	2022	2023	2024
3 Phases Renewables	9	No Data	No Data	8	9
Brookfield Renewable Energy Marketing U.S.	-	-	-	No Data	No Data
Calpine Energy Solutions	No Data	13	15	No Data	No Data
Constellation NewEnergy	No Data	No Data	26	40	43
Commercial Energy of Montana, Inc. (dba Commercial Energy of CA)	-	-	-	0	0
Calpine PowerAmerica	No Data	5	5	No Data	No Data
Direct Energy Business	No Data	No Data	10	10	No Data
BP Energy Retail	No Data	No Data	No Data	No Data	No Data

141 The ESPs have varying interpretations of the data request categories and, therefore, reported RPS employees may not be directly comparable.

Table 44: Total Number of ESP RPS Employees from 2020 – 2024					
	2020	**2021**	**2022**	**2023**	**2024**
Just Energy Solutions	6	No Data	5	4	7
Liberty Power Delaware	No Data	No Data	No Data	No Data	No Data
Liberty Power Holdings	No Data	No Data	No Data	No Data	No Data
Palmco Power	No Data	No Data	No Data	0	No Data
Pilot Power Group	0	3	3	2	2
Shell Energy North America	No Data	No Data	No Data	No Data	No Data
UC Regents	2	2	3	4	4

Table 44: Total Number of ESP RPS Employees from 2020 – 2024
Data Source: ESPs, September 2024

The CPUC requested data from all ESPs that were operational in 2024. Some ESPs reported that they did implement workforce development and diversity policies to build a workforce that promotes diversity and inclusion in the renewable energy sector. One ESP reported that it engaged in employee recruitment through diversity-focused job boards, and three ESPs reported employee recruitment activity through general job boards. Two ESPs reported relations with universities and campuses, and the same number of ESPs reported that it had invested in employee training programs. One ESP noted that it had a partnership with at least one business resource group.

RPS Challenges and Policy Recommendations

Challenge 1: Generation and Supply Chain Issues

California electricity sellers, under state law, must provide 60 percent of retail sales from renewable energy by 2030, ramping up to the goal of 100 percent renewable and zero carbon resources by 2045. While California recently hit a milestone: 100 days this year with 100 percent carbon-free, renewable energy for at least a part of each day[142], California faces a significant challenge in coming years build enough generating facilities to meet RPS requirements. Meeting these requirements is further challenged by a series of mandates that will require more carbon-free energy due to the increase in electric transportation that will be on the roads and the number of electric appliances which will increase in homes.

Issue One: Disrupted Supply Chain Flows

A recent issue faced by commercial entities looking to supply retail sellers with renewable generation is that of obtaining the inventory they need to establish new renewable energy generating facilities. While the global supply chain issues which resulted from the COVID-19 pandemic have mostly been resolved, there are now political pressures resulting in tariffs being placed on key products needed for renewable energy generation. In the United States, the United States International Trade Commission (USITC) and the US Department of Commerce (DOC) are actively conducting antidumping and countervailing duty (AD/CVD) investigations on solar cells and modules produced in various countries. If these investigations find cause, these could lead to even more tariffs. These tariffs were imposed on countries which were identified for non-competitive conduct. Tariffs thus far have been placed mainly on the polysilicon used in making solar panels and the lithium used in making large scale batteries for energy storage. China dominates supply chains for key renewables materials, accounting for almost 90 percent of global polysilicon supply in 2023, projected to reach to 94 percent in 2024, while_upwards of 70 percent of lithium refining capacity is based in China[143]. This highlights the lack of domestic supply chains in the renewables space, with the US accounting for 3 percent of global polysilicon production and 2 percent of lithium refining. The US tariffs on imports from certain countries and companies complying with US Anti-dumping and Countervailing Duty orders have led to significant bottlenecks in the solar supply chain.[144]

Secondly, the Uyghur Forced Labor Prevention Act (UFLPA) prohibits the importation of goods produced in the Xinjiang region of China, absent proof that forced labor has not been involved in their manufacture. The Xinjiang Uyghur Autonomous Region (XUAR) is specifically significant because polysilicon is a key

142 CalMatters: "CA Hits Milestone Towards 100% Clean Energy", August, 2024.
143 Wood Mackenzie Research, "How to Manage Supply Chain Issues", April 7, 2024.
144 Wood Mackenzie Research, "Sunny Skies Ahead: the solar market and supply chain in 2024 and beyond", September 2024.

material for the manufacture of solar panels, and nearly half of the world's polysilicon is produced in XUAR[145]. Tariffs placed on these certain products most often passed on to the customer resulting in the inflation of prices.

Issue Two: Renewable Projects Requires Investment Capital and Labor

Whether the renewable energy project is based on solar, wind, geothermal, or some other technology, they all have some aspects in common. They all require a large initial capital investment, and a relatively long payback period compared to other investments. While historically solar tax credits have incentivized investment, it was capped at a rate of 26 percent and was set to expire in 2024 which discouraged further investment. Interest rates, which have risen recently, make cost of capital more expensive as well. These factors made projects more costly to initiate and investors less attracted to invest in renewable energy projects. This came in the face of increasing climate change issues and global calls for a reduction in the use of fossil fuels. Additionally, as California transitions away from our dependence on fossil fuels and becomes increasingly reliant upon new renewable energy sources, there will be a need for a trained workforce who would run the new infrastructure and be able to work with new processes.

Recommendations

Although we are focusing on California's issues in this report, perhaps no other factor has been more impactful to California's renewable energy progress in 2024 than that of the federal law the Inflation Reduction Act (IRA) which was signed into law on August 16, 2022. Combined with the Bipartisan Infrastructure Law (BIL) and historic state investments, the Biden-Harris Administration is helping remake California's infrastructure – from new clean energy and power grid improvements to transit and high-speed rail[146]. The CPUC should continue to work with other agencies and stakeholders on the implementation of the IRA and BIL such that the benefits support the further development of clean energy resources and investment into necessary infrastructure.

Additionally, as the IRA tax incentives begin to be utilized, a short-term issue has been created by the backlog of projects that were held up pending implementation of the IRA. With these projects now being greenlighted, the market is experiencing a surge in demand for both equipment and labor. With such possible swings among resources which in turn impacts projects, it is prudent to take multiple actions and approaches to resolve the myriads of challenges impacting RPS project development to reduce project and portfolio risk. Retail sellers should consider prioritizing project and resource diversity in meeting their RPS requirements. They should also maintain reasonable procurement margins at both the equipment and project levels so that neither shortages of some key components nor potential project failures results in business disruptions or compliance failures.

145 Morgan Lewis, "How Responsible Labor and Trade Issues Affect the Solar Energy Industry", February 8, 2023.

146 Governor of California, www.gov.ca.gov/2024/08/15/california-celebrates-two-years-of-the-inflation-reduction-act-a-win-for-jobs-climate-and-infrastructure.

In addition, the CPUC should continue participation in the Tracking Energy Development Strike Force – a joint effort of staff at the CPUC, CEC, CAISO and Governor's Office of Business and Economic Development to track new energy project development and interconnections – to assist in identifying barriers to clean energy project developments and coordinating action to address them.

Challenge 2: Interconnection Demand

Issue

Interconnection is the multi-step process of connecting new electricity generators, such as wind and solar, to the electric grid, and has multiple risk factors that can delay or prevent commercial operation for dependent projects. Over the past three years, an increasing number of interconnection requests to the California Independent System Operator (CAISO) has presented a significant ongoing challenge for developers, transmission owners, and state authorities that deal with processing and permitting applications. On average, CAISO received 113 interconnection requests annually from 2010 to 2020.[147] That number grew to 373 requests in 2021 and then to 541 requests during the submission window that closed in 2023.[148]

These interconnection requests are predominantly solar and storage projects which are needed to meet California's RPS requirements and greenhouse gas (GHG) reduction goals. While the robust development interest is positive in terms of momentum to meet the goals, CAISO estimates the interconnection queue now contains more than three times the potential energy needed to achieve the objective of 100 percent clean energy by 2045 and far exceeds the available and planned grid transmission capacity to deliver this power to customers.[149]

The large number of interconnection project requests in the last few years overwhelmed CAISO's interconnection study procedures as well as planning and engineering resources across the industry, creating a critical challenge to efficiently and cost effectively advance the most viable projects to operational status. This situation prompted the creation of CAISO's Interconnection Process Enhancements (IPE) initiative in February 2023, which has been supported by the CPUC and CEC as a part of the larger effort by these agencies to coordinate renewable generation and transmission planning.

In June 2024, CAISO's Board of Governors approved a package of interconnection process reforms crafted over a year of extensive engagement with IPE stakeholders. Broadly described, these reforms consist of two related components. The first change is for CAISO to assess transmission availability and prioritize interconnection projects in zones where capacity currently exists, or new transmission has been approved.

147 Data source: CAISO Supercluster Interconnection Procedures Issue Paper & Draft Final Proposal, May 2021: https://www.caiso.com/documents/issuepaper-draftfinalproposal-superclusterinterconnectionprocedures.pdf.

148 Data source: CAISO Tariff Amendment to Implement Track 2 of Interconnection Process Enhancements Submittal to the Federal Energy Regulatory Commission, August 2024: https://www.caiso.com/documents/aug-1-2024-tariff-amendment-interconnection-process-enhancements-2023-er24-2671.pdf.

149 Ibid.

The second reform will involve scoring interconnection requests based on commercial interest, project viability, and system need. The top ranked projects, located in zones where transmission capacity is available, would advance to the CAISO interconnection study process, where they would be more fully evaluated. These reforms build on requirements established in July 2023 by the Federal Energy Regulatory Commission (FERC), which set new standards for interconnection processes around the country.[150] CAISO submitted its IPE reforms to FERC in August 2024 and is currently awaiting approval.

Recommendation

Recognizing the IPE reforms will take some time to fully implement once approved, the CPUC as a stakeholder should continue to work with CAISO to provide input and feedback as the reforms are put into practice. The CPUC should also continue to work with CAISO and its Transmission Planning Process (TPP). Additionally, the CPUC will work with retail sellers and developers to continue monitoring project development and delays. The Tracking Energy Development Task Force (TED), which the CPUC is a part of, has been effective at identifying and coordinating actions to address barriers that may be impacting energy development and interconnections throughout the state and the CPUC should continue with the effort.

Given the time expected to address the projects in the queue and implement the process reforms, retail sellers should consider these timing and risk factors in RPS planning and procurement processes. For example, similar to IOUs, non-IOUs should continue to consider incorporating stricter interconnection status requirements into their RPS procurement processes as eligibility criteria for solicitations or contract executions, such as limiting bids to projects that have completed CAISO's full interconnection evaluation process to reduce risk of not meeting RPS requirements. Additionally, retail sellers should consider prioritizing contracts with projects at advanced interconnection stages and projects that are located within zones with available transmission capacity.

Retail sellers should also consider ways to improve tracking dependent generation and storage resources that are tied to interconnection projects to determine which interconnection projects will have the greatest impacts if delayed. Additionally, retail sellers should examine the various reasons why interconnection projects are delayed and determine which issues result in the longest delays and have the most dependent generation and storage resources.

Challenge 3: Bioenergy

The state looks to effective bioenergy programs to play additional contributing roles in addressing waste reduction, waste diversion, and mitigation of wildfire risks. Although bioenergy is a comparatively expensive renewable resource, State biomass waste management policies have been expanded in recent years with new

150 See Explainer on the Interconnection Final Rule FERC Docket No. RM22-14-000, Order No. 2023: https://www.ferc.gov/explainer-interconnection-final-rule#_ftn1.

urban organic waste diversion mandates and increased restrictions on open burning of biogenic agricultural waste. Within the RPS program, there are two bioenergy procurement programs: the Bioenergy Renewable Auction Mechanism (BioRAM) and Bioenergy Market Adjusting Tariff (BioMAT) which assist in meeting these state policies. The CPUC has implemented numerous revisions to its bioenergy programs to meet the State's evolving biomass policies. Future policies or program changes may occur as bioenergy technologies are considered RPS-eligible and may contribute to achieving California's SB 100 goals for renewable and zero-carbon resources by 2045. Data for the programs, research, and emerging trends should be considered when considering any future changes.

Underutilization of Fuel from Biomass High Hazard Zones

The BioRAM program requires the three IOUs to procure 146 MWs of bioenergy from facilities that use High Hazard Zone (HHZ) fuel, as defined by CAL FIRE, to aid in mitigating the risk of wildfires. By sourcing HHZ fuel stock, the BioRAM program is intended to provide a waste disposal solution for dead or dying trees that present increased wildfire risk in HHZs. However, the potential of the BioRAM to aid in mitigating wildfire risk and support sustainable forest management appears to remain unfulfilled. For the 2023 reporting period, four of the six BioRAM facilities contracted met the HHZ fuel use requirement for the entire year.[151] One facility opted out for two months and another facility opted out for three months. Although it is unclear precisely why these two facilities opted out or did not otherwise meet their fuel use requirements, CPUC staff analysis suggests that insufficient supply chain capacity, fuel supply costs (including significantly increased hauling and processing costs), and inconsistent fuel supplies can be barriers to accessing reliable, cost-efficient biomass fuel stock from HHZs.

Recommendation

The CPUC will continue to track the amount of fuel used at bioenergy facilities that is sourced from high fire risk areas, as well as the total costs of fuel and energy procurement, to further understand bioenergy cost-effectiveness, as well as the general efficacy of the BioRAM program. Additionally, the CPUC will continue to explore other incentives and penalties that might increase HHZ fuel use at BioRAM facilities in order to maximize their potential benefit in reducing wildfire risk and supporting sustainable forest management goals. For example, the CPUC could consider an alternate contract pricing mechanism for those months when a bioenergy facility opts out of using HHZ fuel stock for any contract extensions.

151 Senate Bill 901 (Dodd, 2018), which was implemented in CPUC Resolution E-4977, modified the BioRAM program, in part, to permit BioRAM facilities to opt out of HHZ requirements.

Bioenergy's Contribution Towards California's Climate Policies and Goals Will Require Ongoing Research

At the regional SB 100 scoping workshops held across the state, stakeholders asked that the definition of "zero-carbon resource" continue to include electricity generated from bioenergy fuel sources. Many stakeholders commented that bioenergy can also contribute meaningfully to the state's system reliability, waste diversion, and wildfire risk reduction goals. Yet, other stakeholders in California view bioenergy differently. This diversity of opinion about bioenergy is reflective of the wide range of typologies broadly grouped into the "bioenergy" category. For example, while the BioRAM program is centered on larger generation facilities typically utilizing older combustion technologies to convert forest waste and/or mill-derived feedstocks, the BioMAT program is focused on conversion of smaller, more diverse organic waste streams - such as diverted food waste, animal manure, and agricultural crop by-products - that largely results in biogas to electricity production. When assessing this wide range of bioenergy programs, many acknowledge significant upside potential to reach RPS program goals, while other stakeholders continue to maintain concerns about the effects of bioenergy generation on regional air quality and local land use impacts.[152]

Unlike other RPS generation categories, there is no singular meaning of the term bioenergy within which to simplify or unify broad stakeholder inputs. The RPS bioenergy program and policy discussion is highly nuanced. Consequently, a complete understanding of the contributions that the full range of bioenergy projects could make towards statewide GHG reductions goals will need continuous updating and re-evaluation as new biofuel conversion technologies are adopted and new biofuel markets are developed. In recent years, California has been trending away from combustion technologies more common at legacy bioenergy facilities and towards more emission-efficient gasification and pyrolysis projects in all biofuels production submarkets. Ongoing applied research analyzing the emissions impacts across all bioenergy project typologies is essential for policy makers requiring a contemporaneous view of California's biofuel market potential. Supply chain analysis is similarly of importance to understanding potential. For example, transportation and processing emissions associated with the sourcing of biomass feedstocks from areas where sustainable forest management practices are being conducted may, in concept, negatively impact any net GHG emission benefits derived from the downstream conversion of that feedstock into biofuel. A fuller systems-based understanding of emissions throughout various biofuel supply chains in California is required.

Recommendation

The CPUC is facilitating a technical working group to develop a set of public life cycle analysis (LCA) modeling tools to measure net GHG emissions from BioMAT program projects. The working group, which includes bioenergy, life cycle, and emissions experts from academia and U.S. Department of Energy national labs, is currently evaluating existing public LCA models developed by other state agencies, such as CARB

152 *See* https://www.energy.ca.gov/sb100.

and CEC-funded Electric Program Investment Charge (EPIC) projects, to apply them to the BioMAT program context. However, modifications to the existing modeling tools are required to enable them to more accurately model net GHG emissions from the various BioMAT technologies.

Once accurate BioMAT LCA tools are developed, follow-on LCA tools could also be developed to quantify the net GHG emissions from the BioRAM program (as well as other energy programs) to better analyze overall environmental performance. The CPUC could then consider whether bioenergy projects procured through its bioenergy procurement programs should require LCA evaluations to ensure net carbon neutrality (or negativity) to ensure that the state's electricity sector is not replacing fossil-fuel carbon emissions with biomass-related emissions that have not yet been fully characterized.

Statewide Bioenergy Markets Are Characterized By Competing End Uses

Emerging renewable energy market segments in the renewable natural gas (RNG) and hydrogen production space will increasingly impact each of the several biofuel feedstock supply chains across California. The secondary result of this increased potential competition for biomass feedstocks could be further constraints on full-scale uptake of the CPUC's existing RPS bioenergy electricity generation programs. The Inflation Reduction Act (IRA) and various state and federal programs will continue to drive demand for new methods of biogas production at price points that are subsidized on both federal and state levels.

For example, the state's biomethane procurement targets and goals (SB 1440, Hueso, Chapter 739, Statues of 2018) will increase demand of biogas. Also, biogenic sources of feedstock for biohydrogen production (SB 1075 (Skinner, Chapter 363, Statues of 2022) have been targeted as a key strategic cornerstone of the state's Hydrogen Hub scoping plan. Further, CARB's Low Carbon Fuel Standard (LCFS) market continues to absorb supply from new biogas production facilities utilizing common biomass feedstocks. The United States Environmental Protection Agency's Renewable Fuel Standard (RFS) program was also recently revised to enhance the market value of RNG for transportation fuel.

The CPUC has been monitoring stakeholder interest in potential BioMAT electricity generation facilities conversions to stand-alone LCFS and RFS biogas production facilities. Project developers with a secure long-term feedstock supply arrangement – whether that be from forest residuals, organic waste diversion, or agricultural derived material - have a widening array of potentially attractive market segments into which they may consider supplying a biofuel energy product.

The trend currently appears to be a subtle but demonstrable shift from electricity production towards renewable natural gas production. The existing RPS bioenergy programs will likely continue to see implementation challenges as the competitive landscape shifts incrementally towards newly subsidized market segments in these emerging RNG biogas production chains.

Recommendation

The CPUC will continue to monitor biofuel market developments common across both RPS and RNG programs. Continued commitment to interagency coordination with counterparties at CEC, CALFIRE, CARB, Governor's Office of Business and Economic Development (GO-Biz) and other key agencies and jurisdictions working on biofuel market growth in California will be essential in maintaining insight into new market realities representing prospective RPS program implementation challenges. More robust engagement on the ground with biofuel market participants as greater competition for and more innovative utilization of California's biomass feedstocks will help the CPUC more readily understand potential program and regulatory issues in real-time.

The critical issue of long-term feedstock contracting which characterizes most successful biofuel projects – whether the project is an RPS or RNG facility - will need to be more thoroughly understood at a policy level should the numerous emerging opportunities for biofuels be fully realized. Furthermore, building a better understanding of biofuel feedstock economics for each renewable energy production outcome could help guide policymakers as they seek policy changes or direct any changes to multiple but competing energy decarbonization programs.

Appendices

Appendix A – About the RPS Program

How the RPS Program Works

The Renewables Portfolio Standard (RPS) program encourages investment in the development of new utility-scale renewable energy facilities to meet the electrical demands of the State of California. RPS is a market-based program where compliance is determined by the quantity of Renewable Energy Credits (REC) procured (1 REC = 1 megawatt hour (MWh)). Eligible renewable generation facilities may be located anywhere within the Western Electricity Coordinating Council (WECC) region. These facilities are permitted to sell RECs to California retail sellers of electricity to meet their RPS obligations, provided the facility meets all RPS eligibility criteria established by the California Energy Commission (CEC).

The CPUC's implementation of the RPS program complements the RPS program administered by the CEC, as well as supports California's climate change policies. The CPUC's compliance process is completed after the CEC verifies RPS-eligible procurement from renewable energy facilities. The CPUC establishes program policy within its RPS rulemaking proceeding and implements legislation through its CPUC decisions to ensure that electricity retailers comply with CPUC rules and State law.

The CPUC's responsibilities in the implementation of the RPS program include:

- Setting policy through a public stakeholder process.
- Reviewing and approving each retail seller's RPS procurement plan.
- Determining and enforcing compliance with procurement requirements.
- Reviewing and approving investor-owned utility (IOU) contracts for RPS-eligible energy.

RPS Procurement Plans

Each year, the IOUs, SMJUs, CCAs, and ESPs are required to submit RPS procurement plans to the CPUC. The RPS Procurement Plan requirement is focused on ensuring that retail sellers have engaged in proper planning for their renewable energy procurement in order to meet RPS requirements. The CPUC reviews retail sellers' RPS Procurement Plans to evaluate their near and long-term RPS forecasts as well as their renewable energy planning and procurement mechanisms.

RPS Plan elements include information on current renewables portfolio information, upcoming solicitation plans for renewable energy, and long-term planning for renewable energy procurement. The plans also include possible RPS compliance delay factors, risk assessment for RPS projects, and plans for sales of renewable energy. RPS Procurement Plans may be found in the RPS proceeding docket.

RPS Compliance Requirements

Progress towards the RPS mandate is measured in several ways, including through the analysis of detailed annual RPS Procurement Plans and RPS Compliance Reports. These documents forecast the compliance status of each retail seller in achieving the statewide mandate.

Retail sellers are required to submit annual preliminary RPS Compliance Reports to the CPUC that contain historical and forecasted data about their renewable procurement. The CPUC evaluates these reports to ensure progress is being made towards the interim targets.

The CPUC works closely with the CEC to manage the RPS program, including compliance determinations. Compliance evaluations and official determinations by the CPUC can only take place after the CEC verifies a retail seller's annual REC claims.

The CEC receives reports from energy retail sellers generated by the Western Renewable Energy Generation Information System (WREGIS)[153] which describes the amount of renewable electricity generated by every RPS-eligible facility. The CEC analyzes the WREGIS reports to determine eligibility of the REC, the quantity of RECs created from each RPS-eligible facility, and retail sellers' RPS procurement claim to ensure each REC claimed is eligible for compliance with the RPS and is only counted once.

Once the CEC has verified the number of RPS eligible RECs, a retail seller can use those RECs to meet its RPS compliance obligations, and those RECs are considered retired. The CPUC is then responsible for reviewing how a retail seller's RPS procurement is classified into portfolio content categories (PCCs) and whether it is consistent with the portfolio balance requirement (PBR), the long-term contract procurement requirement, and the procurement quantity requirement (PQR). These three compliance requirements are explained in further detail in Appendix B below.

RPS Excess Procurement Rules

RECs that are in excess of what is needed to fulfill RPS obligations in one compliance period may be "banked" and used in subsequent compliance periods. SB 2 (1X) established the ability for a retail seller to carry over procurement from one compliance period to another. The calculations for excess procurement rely on a combination of the PCC classification of the RECs and whether the RECs are associated with short-term or long-term contracts.

Beginning in 2021–2024 compliance period, all excess PCC 1 RECs can be banked, regardless of whether they are associated with short- or long-term contracts; however, no PCC 2 or PCC 3 RECs can be banked.[154]

153 The Western Renewable Energy Generation Information System (WREGIS) is an independent renewable energy tracking system for the region covered by the Western Electricity Coordinating Council (WECC).

154 *See* D.17-06-026, as modified by D.17-11-037 for more detail.

Appendix B – How RPS Compliance Works

To achieve RPS compliance, retail sellers must meet three requirements:

- Procurement Quantity Requirement (PQR);
- Portfolio Balance Requirement (PBR); and
- Long-Term Contract Procurement Requirement.

As applicable, a retail seller's RPS procurement can contribute to meeting more than one requirement (e.g., all of a retail seller's long-term RPS contracting will eventually contribute to meeting its PQR), but the criteria of all three requirements must be met for a retail seller to be considered compliant with the RPS program, with the exception of small and multi-jurisdictional utilities (SMJUs), which are exempt from the PBR.[155]

Procurement Quantity Requirement (PQR)

The PQR is the statutorily[156] set percentage of RPS-eligible procurement required in a compliance period. The CPUC implemented annual percentage targets in D.19-06-023, pursuant to SB 100.[157] The annual percentage target is multiplied by a retail seller's total retail sales in each year for a given compliance period. Retail sellers must meet the PQR established for each compliance period, or they are considered non-compliant with the RPS program and assessed a penalty of $50/REC.

Portfolio Balance Requirement (PBR)

California's RPS program defines all renewable procurement acquired from contracts executed after June 1, 2010, into one of three portfolio content categories (PCCs). The PCC classifications are also instrumental in determining a retail seller's compliance with the RPS program.

- **Category 1:** Renewable energy credits (RECs) with associated energy from facilities with a first point of interconnection within a California Balancing Authority (CBA), or facilities that schedule electricity into a CBA on an hourly or sub-hourly basis.
- **Category 2:** RECs with incremental electricity, and/or substitute energy, from outside a CBA. Generally, Category 2 RECs are generated from out-of-state renewable facilities and require a Substitute Energy Agreement that details the simultaneous purchase of energy and RECs from an RPS-eligible facility.
- **Category 3:** Unbundled RECs that do not include the physical delivery of the energy attached to the REC. Generally, Category 3 RECs are associated with the sale and purchase of the RECs themselves, not the energy.

155 *See* Appendix A: About the RPS Program for more detail.

156 Defined by Public Utilities Code § 399.15(b)(2)(B) and were first implemented by the CPUC in 2011. The code has been amended to increase the PQR multiple times, with the most recent amendment being from SB 100 in 2018, increasing to 60 percent for all subsequent three-year compliance periods.

157 *See* D.19-06-023 for more information: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M307/K595/307595168.PDF.

The PBR is defined by the minimum and maximum of the three PCCs, which are delineated by type of renewable procurement. Most retail sellers have specified requirements for the balance or mix of procurement from contracts that are executed after June 1, 2010. Specifically, these retail sellers must procure a minimum level of Category 1 RECs, which increases over the initial three multi-year compliance periods.[158] There is also a maximum limit on the amount of Category 3 procurement that may be used in each compliance period, which decreases over the same timeframe.

The figure below depicts the PBR limits and how they adjusted across compliance periods until 2020, at which point they remain at those limits for each successive compliance period.

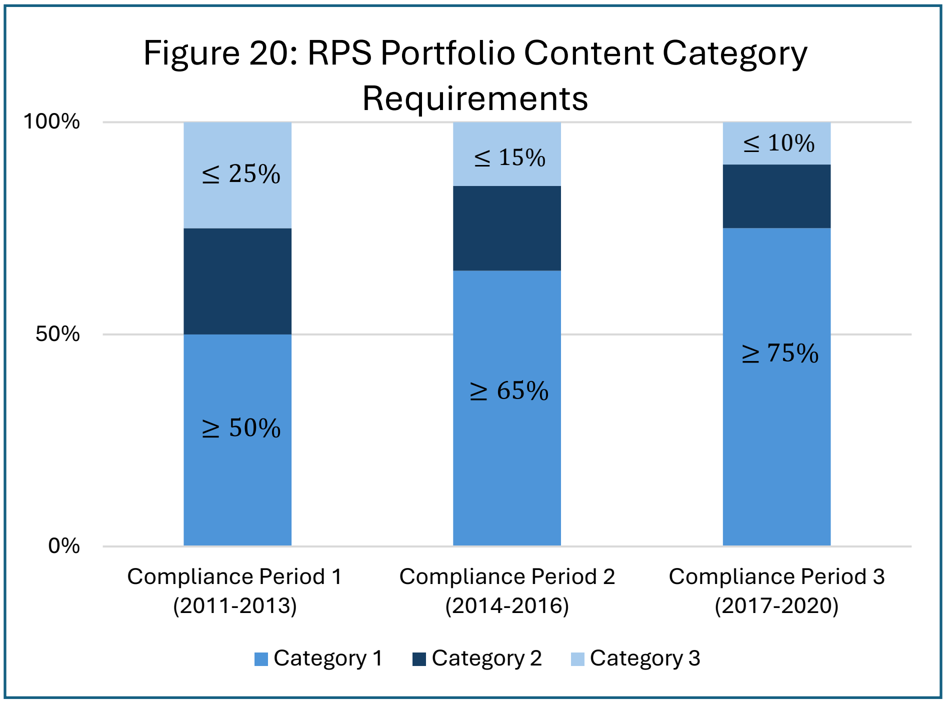

Figure 20: RPS Portfolio Content Category Requirements

All retail sellers except for SMJUs must follow the above specified requirements for the balance or mix of procurement from contracts that are executed after June 1, 2010. The SMJUs are exempt from the portfolio balance requirements and may procure any amount of RPS-eligible energy from any of the categories.[159]

Long-Term Contract Procurement Requirement

All electric retail sellers must procure a specified percentage of their RPS portfolio from long-term contracts, defined as 10 or more years.[160] For the first three compliance periods through 2020, 0.25 percent

158 *See* Public Utilities Code § 399.16(c) for additional information. Also, for more details on the RPS Compliance rules, visit https://www.cpuc.ca.gov/General.aspx?id=3856.
159 Pursuant to Public Utilities Code § 399.17 and 399.18.
160 *See* Public Utilities Code § 399.13(b) for additional information.

of a retail seller's total electricity portfolio were required to come from long-term contracts. SB 350 increased this requirement, implemented in D.17-06-026, to 65 percent of all RPS procurement must come from long-term contracts beginning in the 2021–2024 compliance period, or in the 2017-2020 compliance period if an electric retail seller elected for early compliance with this requirement.

Appendix C – Summary of Accomplishments from January 2023 – October 2024

Month/Year	Accomplishments
January 2023	▪ IOUs, SMJUs, CCAs, and ESPs filed Final 2022 RPS Procurement Plans ▪ CEC adopted Verification Report for compliance period 2017-2020
February 2023	▪ CPUC staff approved the IOUs' proposed long-term pro-forma Market Offer contracts and solicitation protocols
March 2023	▪ IOUs, CCAs, and ESPs submitted Final 2017-2020 RPS Compliance Reports ▪ CPUC adopted D.23-03-009 closing Rulemaking 15-02-020 ▪ CPUC held a prehearing conference for R.22-10-010 implementing AB 843
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 ▪ RPS Procurement Plans Webinar ▪ 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
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

Month/Year	Accomplishments
September 2023	▪ CPUC approved Order Extending Statutory Deadline of R.18-07-003 to July 31, 2024
October 2023	▪ CPUC issued proposed Decision implementing AB 843 ▪ CPUC adopted D.23-10-006 denying ReMAT PFM ▪ CPUC adopted Resolution E-5288 implementing SB 1109 (Caballero, Chapter 364, Statues of 2022) extending BioRAM program
November 2023	▪ CPUC approves IOUs' proposed long-term Market Offer contracts. ▪ CPUC adopted Resolution E-5295 approving six long-term PPSAs
December 2023	▪ CPUC adopted D.23-12-008 approving the 2023 RPS Procurement Plans ▪ CPUC adopted D.24-01-006 and D.24-01-033 denying two BioMAT PFMs ▪ CPUC adopted Resolution E-5305 approving a long-term Market Offer
January 2024	▪ IOUs, CCAs, SMJUs, and ESPs filed Final 2023 RPS Procurement Plans ▪ CPUC issues Order Instituting Rulemaking (OIR) R.24-01-017 to continue implementation and administration of the California RPS program ▪ CPUC adopted Resolution E-5297 approving a PPA for a zero-emissions product from Hybrid Resource Products
February 2024	▪ CPUC adopted D.24-02-047 adopting 2023 preferred system plan
March 2024	▪ CPUC adopted D.24-03-003 denying a BioMAT PFM
April 2024	▪ CPUC notified Retail Sellers of the final determinations for the 2017-2020 compliance period
May 2024	▪ CPUC issued the 2024 Padilla Report on Costs and Cost Savings for the RPS Program to the Legislature, pursuant to Public Utilities Code § 913.3: https://www.cpuc.ca.gov/RPS_Reports_Data/ ▪ CPUC issued the Assigned Commissioner and Assigned Administrative Law Judge's Ruling issued identifying issues and schedule of review for 2024 RPS Procurement Plans ▪ CPUC issued a Scoping Memo for R.24-01-017 to set forth the initial schedule and issues for consideration in the RPS proceeding ▪ CPUC approved IOUs' recommendation to refrain from scheduling additional VAMO processes. ▪ CPUC adopted Resolution E-5313 approving SCE Renewables MTR PPAs ▪ CPUC adopted Resolution E-5318 approving SDG&E's RPS Solicitation Protocols
June 2024	▪ RPS Procurement Plans Webinar ▪ CPUC issued an Assigned Administrative Law Judge's Ruling requesting party comments on a Staff Proposal for clarifying RPS Procurement Plans

Month/Year	Accomplishments
	confidentiality rules ▪ Adoption of 2024 updated administratively set fixed avoided-cost rates for the ReMAT (Resolution E-5323)
July 2024	▪ IOUs, SMJUs. CCAs, and ESPs submitted Draft 2024 RPS Procurement Plans ▪ CPUC adopted Resolution E-5333 approving SCE Renewables MTR PPAs
August 2024	▪ IOUs, CCAs, and ESPs submitted annual RPS Compliance Reports ▪ CPUC adopted Resolution E-5343 approving PacifiCorp long-term REC contract with 3Degrees Group, Inc. ▪ CPUC adopted D.24-08-064 - Decision Determining Need For Centralized Procurement Of Long Lead-Time Resources ▪ CPUC launched new RPS Database
September 2024	▪ CPUC issued proposed Decision on Motions For Waiver Of Renewables Portfolio Standard Program Requirement For Compliance Period 2017-2020
October 2024	▪ CPUC adopted D.24-10-009 on Motions For Waiver Of Renewables Portfolio Standard Program Requirement For Compliance Period 2017-2020

Appendix D – Glossary of Acronyms and Terms

(BDT) Bone Dry Tons: BDT is commonly accepted to be a 1:1 equivalent with megawatt-hours (MWh) and refers to the measurement of biomass that has a 0 percent moisture content.

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

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

(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.

(CBA) California Balancing Authority: A balancing authority is charged with maintaining the safe and reliable transportation of electricity on the power grid and ensures transparent access to the transmission network and market transactions.

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

(CPCN) Certificate of Public Convenience and Necessity: A legal permission granted to a company or individual by a government entity to operate in a specific area or provide a specific service.

(DA) Direct Access: DA is a retail electric service option whereby customers may purchase electricity from an ESP. An ESP is a non-utility entity that offers electric service to customers within the service territory of an IOU. The IOU is still responsible for the transmission and distribution for Direct Access customers.

(DAC) Disadvantaged Communities: DAC refers to the areas throughout California which most suffer from a combination of economic, health, and environmental burdens.

(DACAG) Disadvantaged Communities Advisory Group: The DACAG is an 11-member advisory group created by Senate Bill 350 (de León, Chapter 547, Statues of 2015) that advises CEC and the California Public Utilities Commission (CPUC) on how to design and implement policies and programs to be more effective on behalf of disadvantaged communities and in the achievement of our clean energy and pollution reduction goals.

(DAC-GT) Disadvantaged Communities Green Tariff: DAC-GT provides utility scale clean energy at a 20 percent bill discount for income-qualified, residential customers in DACs who may be unable to install solar on their roof.

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

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

(GHG) Greenhouse Gas: A gas that contributes to the greenhouse effect by absorbing infrared radiation, e.g., carbon dioxide, methane, nitrous oxide and fluorinated gases.

(GTSR) Green Tariff Shared Renewables: The GTSR program expands access to renewable energy resources to all ratepayers who are currently unable to access the benefits of onsite generation and creates a mechanism whereby commercial customers and groups of individuals can meet their needs with electrical generation from eligible renewable energy resources.

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

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

(IPE) Interconnection Process Enhancements: CAISO's 2023 IPE initiative, also referred to as Track 2, focused on modifications to the interconnection queue management process with the goal of reducing the number of projects backlogged in the queue and advancing the most viable projects toward interconnection and commercial operation.

(IRP) Integrated Resource Plan: A planning mechanism to consider all the CPUC's electric procurement policies and programs to ensure California has a safe, reliable, and cost-effective electricity supply. The CPUC implements an integrated resource planning process that will ensure that retail sellers meet targets that allow the electricity sector to contribute to California's economy-wide greenhouse gas emissions reductions goals.

(LCA) Lifecycle Assessment: Lifecycle Assessment estimates the net impact of emissions from greenhouse gas emissions and can estimate the net emissions of nitrogen oxides, sulfur dioxides and particulate matter attributed to most fuel resource categories.

(LCBF) Least-Cost Best-Fit: Evaluation method for RPS resources that considers cost of procurement while also ensuring that the specific needs of the procurement are being fulfilled.

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

(NTP) Notice to Proceed: Formal communication to commence construction.

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

(PBR) Portfolio Balance Requirement: The PBR is one of the requirements that LSEs must meet to achieve RPS Compliance. California's RPS program defines all renewable procurement acquired from contracts executed after June 1, 2010, into one of three portfolio content categories (PCCs): Category 1, Category 2, and Category 3. The PBR establishes minimum and maximum amounts of the three PCCs that must be used for RPS compliance. A more detailed explanation of the PBR, PCCs, and RPS compliance is provided in Appendix B.

(PCC) Portfolio Content Category: California's RPS program defines all renewable procurement acquired from contracts executed after June 1, 2010, into one of three portfolio content categories (PCCs). A more detailed explanation of the PCCs is provided in Appendix B.

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

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

(POU) Publicly Owned Utility: POUs are governed by locally elected officials and serve a local community's electricity needs. As POUs are not CPUC-jurisdictional entities, they report their RPS compliance to the CEC.

(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.

(PPR) Program Participation Request: Application form which includes supporting documentation (e.g., Interconnection study, single line diagram, etc.) to request participation in the program.

(PQR) Procurement Quantity Requirement: The PQR is one of the requirements that LSEs must meet to achieve RPS Compliance. The PQR is the statutorily set percentage of RPS-eligible procurement required in a compliance period. It is calculated by multiplying the annual percentage target by a retail sellers' total retail sales in each year for a given compliance period. A more detailed explanation of the PQR and RPS compliance is provided in Appendix B.

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

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

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

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

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

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

(TED) Tracking Energy Development Task Force: The TED is a joint effort of staff at the CPUC, California Energy Commission (CEC), CAISO, and Governor's Office of Business and Economic Development (Go-Biz) to track new energy projects under development, provide project development support as appropriate, identify barriers, and coordinate action across agencies.

(TPP) Transmission Planning Process: Each year the CAISO conducts its TPP to identify potential system limitations as well as opportunities form system reinforcements that would improve reliability and efficiency. The TPP core product is the ISO Transmission Plan, which provides an evaluation of the control grid, examines reliability requirements and projects, summarizes key collaborative activities, and provides details on key study areas and associated findings.

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

(WECC) Western Electricity Coordinating Council: A non-profit that promotes bulk power system reliability in the geographic area known as the Western Interconnection.

(WREGIS) Western Renewable Energy Generation Information System: WREGIS is a tracking system for RECs that covers the Western Interconnection territory and is operated by WECC.

Appendix E – California's Active Electricity Retail Sellers

Investor-Owned Utilities	Small and Multi-Jurisdictional Utilities	Community Choice Aggregators	Electric Service Providers
Pacific Gas and Electric Company (PG&E)	Bear Valley Electric Service	Apple Valley Choice Energy	3 Phases Renewables
San Diego Gas & Electric Company (SDG&E)	Liberty Utilities	Ava Community Energy (formerly East Bay Community Energy)	BP Energy Retail Company (formerly EDF Industrial Power Services)
Southern California Edison Company (SCE)	PacifiCorp	Central Coast Community Energy	Brookfield Renewable Energy Marketing
		Clean Energy Alliance	Calpine Energy Solutions
		Clean Power Alliance of Southern California	Calpine Power America
		CleanPowerSF	Commercial Energy of California
		Desert Community Energy	Constellation New Energy
		Energy for Palmdale's Independent Choice	NRG (previously Direct Energy Business)
		King City Community Power	Pilot Power Group
		Lancaster Energy	Shell Energy North America
		Marin Clean Energy	Tiger Natural Gas
		Orange County Power Authority	UC Regents
		Peninsula Clean Energy	
		Pico Rivera Innovative Municipal Energy	
		Pioneer Community Energy	
		Pomona Choice Energy	
		Rancho Mirage Energy Authority	
		Redwood Coast Energy Authority	
		San Diego Community Power	

Investor-Owned Utilities	Small and Multi-Jurisdictional Utilities	Community Choice Aggregators	Electric Service Providers
		San Jacinto Power	
		San Jose Clean Energy	
		Santa Barbara Clean Energy	
		Silicon Valley Clean Energy	
		Sonoma Clean Power	
		Valley Clean Energy	

Appendix F – Public Utilities Code Section 913.4

In order to evaluate the progress of the state's electrical corporations in complying with the California Renewables Portfolio Standard Program (Article 16 (commencing with Section 399.11) of Chapter 2.3), the commission shall report to the Legislature no later than November 1 of each year on all of the following:

(a) The progress and status of procurement activities by each retail seller pursuant to the California Renewables Portfolio Standard Program.

(b) For each electrical corporation, an implementation schedule to achieve the renewables portfolio standard procurement requirements, including all substantive actions that have been taken or will be taken to achieve the program procurement requirements.

(c) The projected ability of each electrical corporation to meet the renewables portfolio standard procurement requirements under the cost limitations in subdivisions (c) and (d) of Section 399.15 and any recommendations for revisions of those cost limitations.

(d) Any renewable energy procurement plan approved by the commission pursuant to Section 399.13, and a schedule and status report for all substantive procurement, transmission development, and other activities that the commission has approved to be undertaken by an electrical corporation to achieve the procurement requirements of the renewables portfolio standard.

(e) Any barriers to, and policy recommendations for, achieving the renewables portfolio standard pursuant to the California Renewables Portfolio Standard Program.

(f) The efforts each electrical corporation is taking to recruit and train employees to ensure an adequately trained and available workforce, including the number of new employees hired by the electrical corporation for purposes of implementing the requirements of the California Renewables Portfolio Standard Program, the goals adopted by the electrical corporation for increasing women, minority, and disabled veterans trained or hired for purposes of implementing the requirements of that program, and, to the extent information is available, the number of new employees hired and the number of women, minority, and disabled veterans trained or hired by persons or corporations owning or operating eligible renewable energy resources under contract with an electrical corporation. This subdivision does not provide the commission with authority to engage in or regulate, or expand its authority to include, workforce recruitment or training.

(g) A systemwide assessment of delays to interconnection or transmission approvals for eligible renewable energy resources or energy storage resources, based on the annual reports submitted to the commission by electrical corporations pursuant to Section 399.13.