2025 CALIFORNIA RENEWABLES PORTFOLIO STANDARD

Annual Report

NOVEMBER 2025

California Public
Utilities Commission

A digital copy of this report can be found at: https://www.cpuc.ca.gov/RPS_Reports_Data/.

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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 requirements, which requires retail sellers meet their load with 60 percent target renewable energy by 2030 and has an interim non-binding target of 44 percent for the calendar year 2024. Consistent with the requirements established in Senate Bill (SB) 1222[1] (Hertzberg, Chapter 842, Statutes of 2016) this annual report describes the progress of the State's electricity retail sellers[2] in meeting the RPS program requirements for 2024 and future years. The report also identifies specific challenges to the RPS program and recommendations for addressing those challenges. Specifically, the report addresses challenges related to current market conditions, including transmission and interconnection issues.

While a current summary of RPS compliance and enforcement is included, a subsequent RPS annual report will address the 2021-2024 compliance period once all renewable energy credit (REC) claims have been verified and final compliance reports have been submitted and reviewed.

This report also satisfies the CPUC's reporting requirements under SB 1174 (Hertzberg, Chapter 229, Statutes of 2022), which requires the CPUC to perform an assessment of reported annual data regarding the relationship between RPS eligible generation and storage resources and transmission development.

Finally, although this report focuses on the RPS program, as mandated by statute, the state's integrated resource planning (IRP) process established under SB 350 (De León) will play an increasing role in future renewable energy 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, Statutes 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 Compliance Period Requirements

A retail seller's RPS compliance is only determined at the end of each RPS compliance period, which is a specified multi-year period. However, annual, non-binding targets for each retail seller are also tracked to forecast compliance and are summarized within this report

- Most retail sellers report meeting or exceeding the 44 percent RPS annual procurement target for 2024.[3]
- Investor-Owned Utility (IOU) compliance is now reliant on banked excess procurement from previous compliance periods, with only one of the three IOUs showing current procurement meeting the 2024 target. However, all three IOUs preliminarily report meeting their 2021-2024 compliance period requirements through banked RECs.

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 under CPUC jurisdiction.
3 Based on preliminary 2024 Annual Compliance Report filings submitted to the CPUC in August 2025.

- Only one of the three Small and Multi-Jurisdictional Utilities (SMJUs) shows procurement meeting the 2024 target. However, all three SMJUs preliminarily report meeting their overall 2021-2024 compliance period RPS requirements due to procurement over earlier years in the compliance period.
- Nearly all Community Choice Aggregators (CCAs) – 24 out of 25 CCAs – show procurement meeting the 2024 target, and all but one preliminarily reported to meet or exceed requirements for the compliance period.
- Of the ten Electric Service Providers (ESPs) actively serving load in 2024, nine showed procurement meeting the 2024 target, and all preliminarily report meeting their 2021-2024 compliance period requirements.

RPS New Contract Prices Decreased Over the Last Decade, but Increased in 2024

- The average RPS eligible energy contract price dropped 5.6 percent per year from 2007 to 2024.
- 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.
- Contract prices for new resources increased in 2024, which was likely driven by an increased demand to meet the end of RPS Compliance Period 2021-2024 requirements, uncertainty of supply chain constraints, and concerns over the potential impact of increasing near-term inflation rates.
    - The average price of IOU, CCA, and ESP contracts executed in 2024 was 8.1¢/kWh compared to 5.9¢/kWh in real-dollar value in 2023.

Large Quantities of Renewable Energy and Storage Resources Have Come Online in Recent Years Despite Delayed In-Service Dates for Transmission Projects

Since 2020, over 24 GW of new clean energy and storage resources have been interconnected to the California Independent System Operator (CAISO) grid, with nearly 7 GW of these new resources coming online in 2024. However, as transmission project delays continue to be a concern in California, their impact on the interconnection of new RPS-eligible renewable generation needs to be assessed regularly. This concern was recently highlighted in the 2025 Executive Order N-33-25, which ordered the CPUC to identify critical generation and storage resources in-development and coordinate with CAISO and utilities to expedite transmission development that support the connection of new resources.

SB 1174 requires electrical corporations that are participating transmission owners (PTOs) to submit annual data on transmission project delays and their impact on RPS-eligible renewable generation and storage resources.

After analyzing the 2025 data, CPUC staff made the following findings:

- The majority of PG&E and SCE in-development transmission projects have been delayed past their original in-service dates at 63 percent and 70 percent, respectively, with 64 percent of reported in-development transmission projects being delayed overall.

- There are 21.8 GW of RPS-eligible renewable generation and storage resources currently in development that depend on transmission projects that have already experienced a delay in coming online.
- Of these RPS-eligible renewable generation and storage resources, 13.2 GW have already been delayed or are at risk of delay due to delayed transmission project timelines, mostly driven by bundling dependencies, materials, and other issues.

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 PTO's SB 1174 data reporting against those listed in the latest Transmission Development Forum (TDF) data and Transmission Project Review (TPR) data to ensure data is more comprehensive and to better track projects. Lastly, the Tracking Energy Development (TED) Task Force is focused on coordinating actions to address barriers that may impact energy development throughout the State.[4]

4 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 and training.
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, Statutes of 2002) with the initial requirement that 20 percent of electricity retail sales must be served by renewable resources by 2017. The program was accelerated in 2006 under SB 107 (Simitian, Chapter 464, Statutes of 2006), which required that the 20 percent mandate be met by 2010. In April 2011, SB 2 (1X) (Simitian, Chapter 1, Statutes of 2011) codified achievement of the 33 percent RPS requirement by 2020. In 2015, SB 350 (De León, Chapter 547, Statutes 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, Statutes 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)[5] 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,

5 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.

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.[6] 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.[7] Among retail sellers within the CPUC's jurisdiction, the IOUs served approximately 47 percent of the 2024 electricity load, while small and multi-jurisdictional utilities (SMJUs) served 1 percent, community choice aggregators (CCAs) served 36 percent, and electric service providers (ESPs) served the remaining 16 percent.

6 *See* the Compliance & Enforcement section for more details on RPS program requirements.
7 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, 2024, to illustrate the state of the RPS program. The data was obtained from the 2025 Draft RPS Procurement Plans[8] and the 2025 RPS Annual Compliance Reports[9] 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 2024, 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 44 percent of their electric load with RPS-eligible resources by December 31, 2024.[10] In general, most retail sellers reported either meeting or exceeding the 44 percent interim RPS target.[11] Figure 1 below shows statewide progress towards meeting the 2030 60 percent RPS requirements.[12] This figure and similar figures below illustrate the renewable energy credits (RECs) produced from online generation and separately 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. The "Expiring Contracts" data represent the amount of generation associated with facilities that may no longer have a Power Purchase Agreement (PPA) with one of the IOUs once their existing contract expires.

8 Each year, retail sellers are required to submit their RPS Procurement Plans to the CPUC for approval. Draft 2025 RPS Procurement Plans were submitted in July 2025.

9 Retail sellers are required to submit preliminary RPS Compliance Reports each year on August 1 to demonstrate progress towards meeting their RPS requirements, though the 2024 RPS Compliance report was delayed until August 22.

10 *See* D.19-06-023.

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

12 *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.

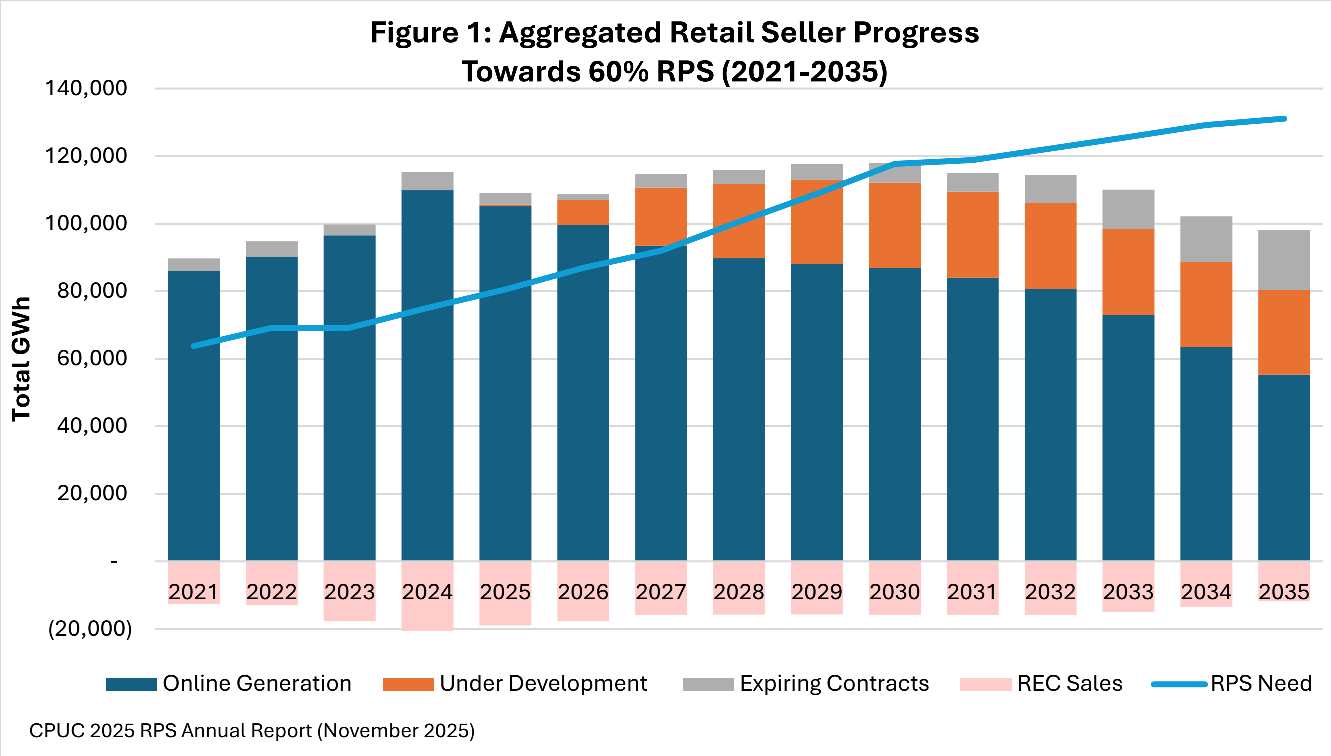

Figure 1: Aggregated Retail Seller Progress Towards 60% RPS (2021-2035)
Data Source: All Retail Sellers' 2025 Draft RPS Procurement Plans (July 2025), Renewable Net Short Calculations

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.[13] The three IOUs are on track to meet their 60 percent 2030 RPS procurement mandate. IOUs have procured and contracted to be on track to either meet or surpass the 2024 annual RPS percentage target of 44 percent by utilizing banked excess procurement from past years. Table 1 below illustrates their 2024 procurement percentages without the use of banked excess procurement towards this requirement.[14]

13 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.

14 Based on their annual Draft 2025 RPS Procurement Plans, as well as Compliance Reports filed with the CPUC in 2025.

Table 1: Investor-Owned Utilities' RPS Procurement Percentages for 2024 (Excludes RECs)	
IOU	**Percent**
Pacific Gas and Electric	28%
Southern California Edison	38%
San Diego Gas & Electric	45%

Table 1: Investor-Owned Utilities' RPS Procurement Percentages for 2024
Data Source: IOUs' 2025 Draft RPS Procurement Plans (July 2025), Renewable Net Short Calculations

The increased usage of banked RECs is forecast to continue in the 2025-2027 compliance period because of portfolio optimization efforts, the Voluntary Allocation and Market Offer (VAMO) process, increasing transportation electrification load, and additional procurement requirements such as those added by SB 1020 (Laird, Chapter 361, Statues of 2022) and the Integrated Resource Planning (IRP) proceeding resulting in a physical net short. Not all IOUs are facing the same degree of physical net short, however, and some may still choose to further optimize their portfolio through sales of renewable electricity and associated RECs[15] to other retail sellers, such as CCAs, ESPs, or POUs. The extent, both in terms of amount and frequency, of optimization via selling RECs varies between the IOUs due to their varying amounts of banked RECs. Additionally, further optimization or REC sales will depend on the amount of future reliability and GHG-free procurements, which are expected to largely consist of RPS-eligible resources, potentially resulting in an eventual elimination of the net short position.

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.[16] The "Expiring Contracts" data represent the amount of generation associated with facilities that may no longer have a Power Purchase Agreement (PPA) with one of the IOUs once their existing contract expires.

15 *See* Appendix D: Glossary and Terms for the full definition of a renewable energy credit (REC).

16 Failure rate assumptions are provided by the IOUs in their renewable net short calculation provided with their Draft Annual RPS Procurement Plans.

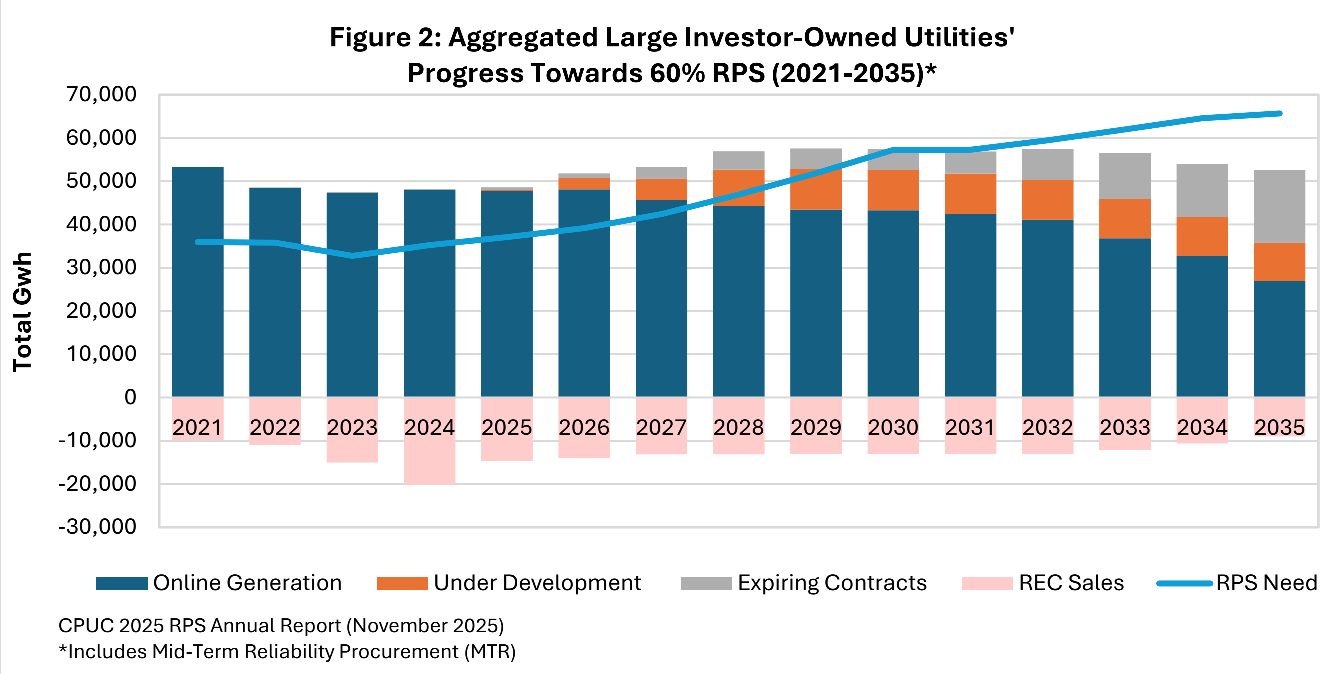

Figure 2: Aggregated Investor-Owned Utilities' Progress Towards 60% RPS (2021-2035)
Data Source: IOUs' 2025 Draft RPS Procurement Plans (July 2025), Renewable Net Short Calculations

Figure 2 above shows that the IOUs were well-positioned to meet RPS requirements in the 2021-2024 compliance period. For future compliance periods, they indicate that they plan to maintain compliance through the increasing use of banked RECs, which are forecast to be necessary 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 2024, none of the IOUs held RPS solicitations although they were authorized to do so, but all three IOUs procured for IRP mid-term reliability requirements during this period, which included some RPS-eligible resources.[17]

Table 2 includes aggregate data[18] to demonstrate the IOUs' actual procurement and forecast RPS procurement percentages. The data shows a decrease in RPS percentages of the aggregated IOUs from 41 percent in 2023 to 35 percent in 2024, largely due to VAMO allocations. Procurement levels out for the current planning horizon, though utilities' plan narratives have indicated resumption of procurement that is not yet significant enough to be reflected in their Renewables Net Short (RNS) reports.

17 The CPUC must approve solicitations outlined in an IOU's annual RPS Procurement Plan in a Decision. D.23-12-008 approved retail sellers' 2024 RPS Procurement Plans.

18 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.

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 2021–2024				Compliance Period 2025–2027			Compliance Period 2028–2030		
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Target	36%	39%	41%	44%	47%	49%	52%	55%	57%	60%
Reported	43%	40%	41%	35%	42%	46%	46%	46%	45%	42%

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' 2025 Draft RPS Procurement Plans (July 2025), Renewable Net Short Calculations

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

Small and Multi-Jurisdictional Utilities (SMJUs)

The SMJUs[19] serving electric load in California are Bear Valley Electric Service, Inc. (BVES), Liberty Utilities, LLC[20] (Liberty), and PacifiCorp.[21] 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 expect to meet their 2021–2024 compliance period requirements and that the SMJU procurements are in line with the annual interim target of 44 percent for 2024. However, in their most recent Compliance Reports, one of the three SMJUs forecasts a physical net short for the 2025-2027 compliance period.

19 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.
20 Formerly CalPeco Electric.
21 d/b/a Pacific Power.

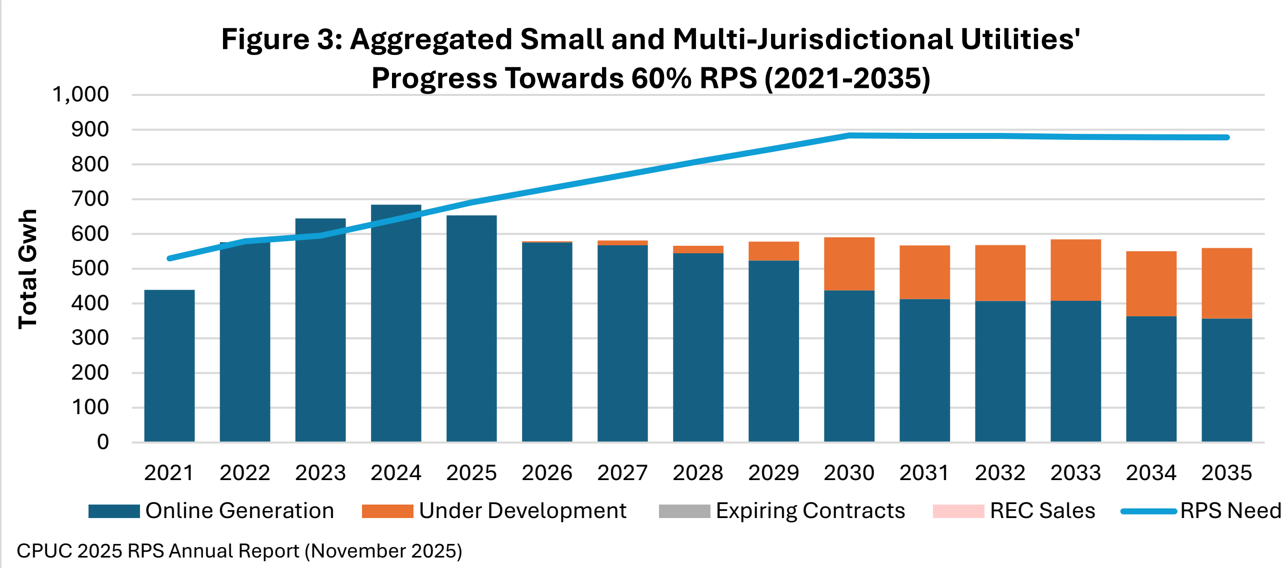

Figure 3: Aggregated Small and Multi-Jurisdictional Utilities' Progress Towards 60% RPS (2021-2035)
Data Source: SMJUs' 2025 Draft RPS Procurement Plans (July 2025), Renewable Net Short Calculations

Looking forward, Table 3 below also illustrates a continued need for procurement in the next compliance period. This is less of a compliance risk for SMJUs than other retail seller types, as they are the only class of retail sellers able to satisfy their compliance requirements entirely with unbundled RECs which tend to be procured from existing RPS-eligible facilities.[22]

Table 3 shows aggregate SMJU data for their actual and forecasted RPS procurement percentages.[23]

Table 3: Aggregated Actual and Forecasted Small and Multi-Jurisdictional Utilities' Gross RPS Percentages for Bear Valley Electric Service, Liberty Utilities, and PacifiCorp[24]										
	Compliance Period 2021–2024				Compliance Period 2025–2027			Compliance Period 2028–2030		
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Target	36%	39%	41%	44%	47%	49%	52%	55%	57%	60%
Reported	30%	38%	45%	47%	44%	39%	38%	37%	36%	30%

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' 2025 Draft RPS Procurement Plans (July 2025), Renewable Net Short Calculations

22 RPS eligible resources must be certified by the CEC as satisfying various criteria, including technology types, location, and metering. For eligibility criteria, see the CEC's RPS Eligibility Guidebook: https://www.energy.ca.gov/programs-and-topics/programs/renewables-portfolio-standard/renewables-portfolio-standard-0

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

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

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.[25] The CCAs play an increasingly significant role in meeting the State's electric reliability, renewable energy, and GHG reduction goals. In 2024, 25 CCAs[26] operated in California and collectively served a total of approximately 61,000 GWh of load or 36 percent of the total electric load within CPUC's jurisdiction.[27] All but one of the operating CCAs procured at or above the 2024 annual RPS target, as shown in Table 5 below.

Table 4 uses aggregated CCA data to show actual and forecasted RPS procurement percentages in the current and next compliance period.[28]

Table 4: Aggregated Actual and Forecasted Community Choice Aggregators' Gross RPS Percentages[29]										
	Compliance Period 2021–2024				Compliance Period 2025–2027			Compliance Period 2028–2030		
Year	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Target	36%	39%	41%	44%	47%	49%	52%	55%	57%	60%
Reported	49%	55%	61%	73%	66%	59%	55%	49%	48%	46%

Table 4: Aggregated Actual and Forecasted Community Choice Aggregators' Gross RPS Percentages
Data Source: CCAs' 2025 RPS Draft Procurement Plans (July 2025), Renewable Net Short Calculations

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. CCA reporting indicates that most will need to procure additional renewable resources to meet the 60 percent RPS target by 2030.[30]

Figure 4 below illustrates the actual and forecasted progress the CCAs have made toward meeting the RPS requirements in aggregate, where they show meeting 2021-2024 and 2025-2027 compliance period requirements. However, this aggregate is impacted by a common CCA objective of exceeding RPS mandates, and this over procurement by some CCAs obscures the risk that other CCAs may be below RPS requirements.

25 Assembly Bill (AB) 117 (Migden, Chapter 838, Statues of 2002) allows local governments to form Joint Powers Authorities to establish community choice energy programs.
26 *See* Table 5 for a list of operating CCAs and their first year of operation.
27 Retail Sellers' Annual RPS Compliance Reports, August 2025.
28 The aggregated RPS compliance percentages are adjusted for CCA launch years and include data from all 25 registered CCAs.
29 Gross RPS percentages reflect physical deliveries only – does not include the usage of banked RECs.
30 *See* Table 5 for a breakdown of RPS position by each individual operating CCA.

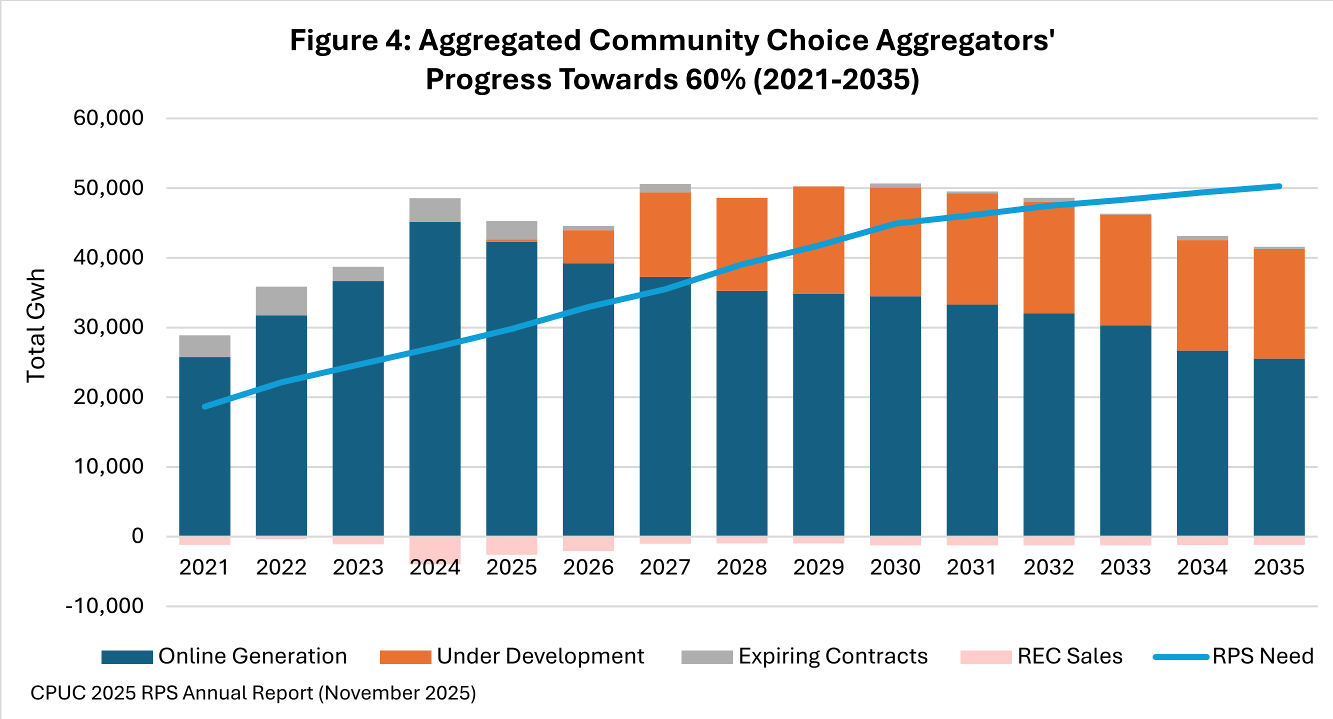

Figure 4: Aggregated Community Choice Aggregator's Progress Towards 60% (2021-2035)
Data Source: CCAs' 2025 Draft RPS Procurement Plans (July 2025), Renewable Net Short Calculations

In 2024, the operational CCAs had an aggregated RPS position of 73 percent. The CCAs' generation has increased to keep pace with RPS requirements through 2025, even exceeding the 2025 forecasted target. The CCAs' forecast 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 nine of the 25 CCAs forecasting an increase in renewable generation from online projects in 2025, while 16 of the CCAs forecast a decrease. Table 5 below details the actual positions of individual CCAs that were operational in 2024 and their forecasted positions for 2025 and 2026.

Although in aggregate CCAs have a long-term procurement need, this varies widely among the 25 CCAs. While some require additional procurement, other CCAs have historically had high internal RPS goals which have resulted in surpluses that some look to optimize through sales, though this approach is much less pronounced than for IOUs.

Table 5: Annual RPS Position of CCAs (%)					
First Year Serving Load	CCA	Actuals		Forecast	
		2023	2024	2025	2026
2010	Marin Clean Energy	68%	74%	77%	62%
2014	Sonoma Clean Power	54%	54%	-	-
2015	Lancaster Choice Energy	49%	59%	62%	41%
2016	Peninsula Clean Energy	51%	49%	63%	73%
2016	CleanPowerSF	60%	90%	-	-
2017	Apple Valley Choice	56%	53%	45%	50%
2017	Pico Rivera	51%	56%	41%	44%
2017	Redwood Coast Energy Authority	30%	62%	58%	71%
2017	Silicon Valley Clean Energy	44%	46%	-	-
2018	Valley Clean Energy Alliance	56%	86%	72%	77%
2018	Central Coast Community Energy	32%	61%	-	-
2018	San Jacinto Power	51%	54%	45%	49%
2018	Rancho Mirage Energy Authority	52%	52%	42%	45%
2018	Clean Power Alliance	73%	80%	-	-
2018	Ava Community Energy	69%	76%	48%	48%
2018	Pioneer Community Energy	44%	47%	44%	49%
2018	San José Clean Energy	57%	66%	-	-
2018	King City Community Power	40%	40%	-	-
2020	Pomona Choice Energy	48%	45%	42%	40%
2020	Desert Community Energy	75%	48%	-	-
2021	Clean Energy Alliance	52%	58%	52%	41%
2021	San Diego Community Power	59%	61%	-	-
2021	Santa Barbara Clean Energy	46%	65%	69%	42%
2022	Energy for Palmdale's Independent Choice	41%	46%	50%	48%
2022	Orange County Power Authority	87%	81%	-	-

Table 5: Annual RPS Position of Community Choice Aggregators (%)
Data Source: CCA Draft RPS Procurement Plans (July 2025), CCA RPS Compliance Reports (August 2025). 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.[31] ESPs currently serve approximately 16 percent or 27,000 GWh of the electricity load within the CPUC's jurisdiction.[32]

Table 6 provides aggregate actual and forecasted RPS procurement percentages of ESPs, and that the ESPs met the 2024 annual RPS interim target of 44 percent, although this is distributed unevenly, and some ESPs will need to procure additional RPS energy to meet the 2025–2027 RPS compliance period requirements.

31 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.

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

Table 6: Aggregate Actual and Forecasted ESPs' Gross RPS Percentages[33]										
	Compliance Period 2021–2024				Compliance Period 2025–2027			Compliance Period 2028–2030		
Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Target	36%	39%	41%	44%	47%	49%	52%	55%	57%	60%
Reported	27%	34%	44%	59%	52%	51%	40%	39%	37%	36%

Table 6: Aggregate Actual and Forecasted Electric Service Providers' Gross RPS Percentages
Data Source: ESPs' 2025 Draft RPS Procurement Plans (July 2025)

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

As illustrated in Figure 5 below, the aggregated ESP data indicate 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, and as stated above, many will need significant procurement to meet the RPS 2025-2027 compliance period and beyond.

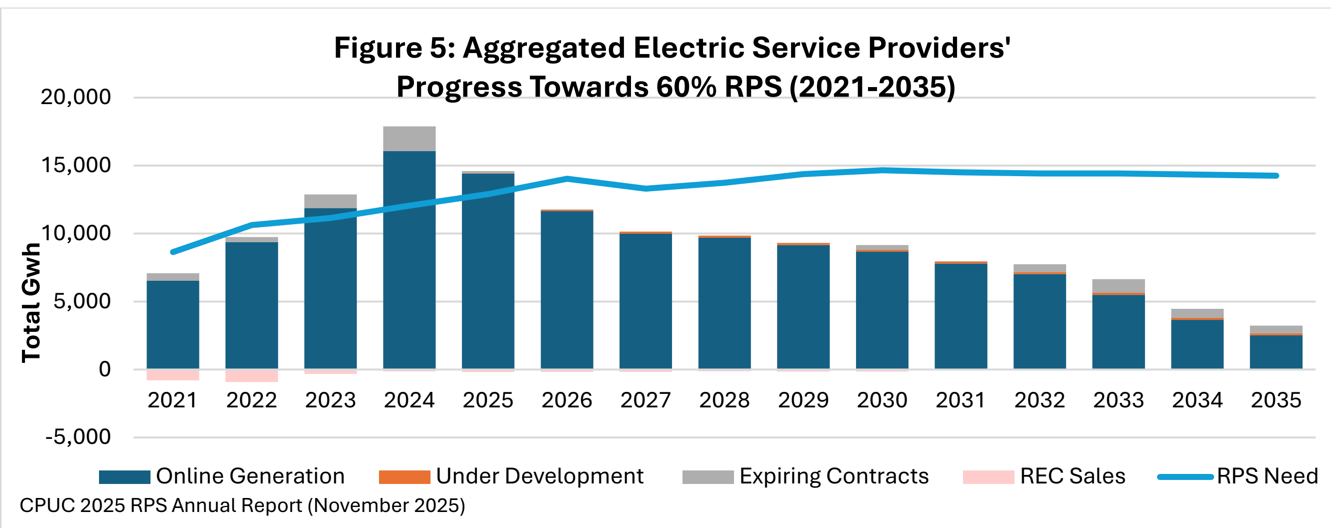

Figure 5: Aggregated Electric Service Providers' Progress Towards 60% RPS (2021-2035)
Data Source: ESPs' 2025 Draft RPS Procurement Plans (July 2025), Renewable Net Short Calculations

Renewable Technology Mix

Resource diversity can contribute to achieving a balanced and reliable energy generation portfolio.[34] Since the inception of the RPS program in 2002, the renewable technology mix of the State's energy portfolio has

33 Gross RPS percentages reflect physical deliveries only – does not include the usage of banked RECs.
34 *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.

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.[35] In 2024, almost half of IOUs' RPS portfolios came from solar, with another third from wind.

Table 7: Portfolio Percentages of 2024 RPS Mix for IOUs (Retired RECs)							
	Bioenergy	**Geothermal**	**Small Hydro[36]**	**Conduit Hydro[37]**	**Solar PV**	**Solar Thermal**	**Wind**
PG&E	8%	1%	6%	-	45%	10%	30%
SCE	<1%	11%	2%	<0.1%	50%	1%	36%
SDG&E	2%	-	<1%	-	51%	-	47%
Weighted Average	**2%**	**8%**	**3%**	**<0.1%**	**49%**	**3%**	**35%**

Table 7: Portfolio Percentages of 2024 RPS Mix for IOUs
Data Source: IOUs' Annual RPS Compliance Reports (August 2025)

Small and Multi-Jurisdictional Utilities (SMJUs)

In 2024, 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 exclusively from solar in 2024, whereas Liberty was balanced between solar and geothermal, with a little bioenergy and small hydro. PacifiCorp had the most diverse renewable energy portfolio mix with six different technologies in its portfolio,[38] with the biggest contributing technologies being wind and solar. Overall, solar made up half of the SMJU portfolio, with the remainder relatively evenly split between bioenergy, small hydro, geothermal, and wind.

35 The technology category of "Bioenergy" consists of biomass, biogas, biodiesel, landfill gas, and municipal solid waste.
36 Small Hydro projects are defined as hydroelectric facilities that are under 30 MW in capacity by the CEC's RPS Eligibility Guidebook.
37 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.
38 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 8: Portfolio Percentages of 2024 RPS Mix for SMJUs						
	Bioenergy	**Geothermal**	**Small Hydro**	**Conduit Hydro**	**Solar PV**	**Wind**
Bear Valley Electric Service	-	-	-	-	100%	-
Liberty Utilities	2%	44%	4%	-	50%	-
PacifiCorp	12%	1%	12%	<0.1%	48%	27%
Weighted Average	**8%**	**15%**	**9%**	**<0.1%**	**50%**	**18%**

Table 8: Portfolio Percentages of 2024 RPS Mix for SMJUs
Data Source: SMJUs' Annual RPS Compliance Reports (August 2025)

Community Choice Aggregators (CCAs)

In 2024, 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 below illustrates the renewable energy portfolio mixes of the CCAs that operated in California in 2024.

Table 9: Portfolio Percentages 202 RPS Mix for CCAs							
	Bioenergy	**Geothermal**	**Small Hydro**	**Conduit Hydro**	**Solar PV**	**Solar Thermal**	**Wind**
Apple Valley Choice Energy	14%	<1%	<1%	-	25%	-	60%
Ava Community Energy	10%	1%	2%	-	48%	-	39%
Central Coast Community Energy	4%	19%	2%	-	65%	-	10%
Clean Energy Alliance	2%	<0.1%	-	-	65%	-	33%
Clean Power Alliance	2%	11%	2%	-	52%	-	33%
CleanPowerSF	2%	16%	1%	<0.1%	52%	-	29%
Desert Community Energy	-	1%	1%	-	34%	-	64%
Energy for Palmdale's Independent Choice	2%	1%	11%	-	45%	-	41%
King City Community Energy	-	-	-	-	82%	-	18%
Lancaster Choice Energy	13%	15%	1%	-	32%	8%	31%
Marin Clean Energy	3%	2%	5%	-	61%	-	29%
Orange County Power Authority	9%	6%	4%	-	51%	-	30%

Peninsula Clean Energy	-	22%	3%	-	38%	-	37%
Pioneer Community Energy	14%	9%	12%	-	55%	-	10%
Pico Rivera Innovative Municipal Energy	17%	<1%	1%	-	22%	-	60%
Pomona Choice Energy	15%	<1%	<1%	-	12%	-	73%
Redwood Coast Energy Authority	25%	<0.1%	6%	-	51%	1%	17%
Rancho Mirage Energy Authority	15%	1%	<1%	-	20%	<1%	64%
San Diego Community Power	11%	<0.1%	1%	-	57%	-	31%
San Jacinto Power	11%	1%	1%	-	30%	-	57%
San José Clean Energy	3%	<1%	1%	-	51%	1%	44%
Santa Barbara Clean Energy	-	<1%	1%	-	30%	-	69%
Silicon Valley Clean Energy	5%	21%	<1%	-	47%	-	27%
Sonoma Clean Power	13%	35%	6%	-	26%	-	20%
Valley Clean Energy Alliance	-	-	2%	-	92%	-	6%
Weighted Average	**6%**	**8%**	**2%**	**<0.1%**	**53%**	**<1%**	**31%**

Table 9: Portfolio Percentages 2024 RPS Mix for CCAs
Data Source: CCAs' Annual RPS Compliance Reports (August 2025)

As Table 9 above shows, CCAs vary widely in resource mix, with most showing a diversity in RPS procurement technologies. The overall mix was similar to the IOUs', with solar contributing over half, and wind almost a third.

Electric Service Providers (ESPs)

Table 10 illustrates the renewable energy portfolio mixes of the ESPs operating in California in 2024.

Table 10: Portfolio Percentages 2024 RPS Mix for ESPs							
	Bioenergy	**Geothermal**	**Small Hydro**	**Conduit Hydro**	**Solar PV**	**Solar Thermal**	**Wind**
3 Phases Renewables	7%	28%	<0.1%	-	60%	-	5%
BP Energy Retail	2%	-	-	-	69%	-	29%
Calpine Energy Solutions	2%	22%	3%	-	51%	-	22%
Calpine Power America	-	22%	-	-	78%	-	-
Commercial Energy of CA	11%	1%	1%	<0.1%	44%	-	44%
Constellation New Energy	5%	3%	4%	-	64%	1%	23%
NRG (formerly Direct Energy Business)	1%	1%	<1%	-	71%	<0.1%	27%
Pilot Power Group	-	-	-	-	34%	-	66%
Shell Energy Solutions	5%	1%	3%	-	40%	-	51%
UC Regents	-	-	-	-	55%	-	45%
Weighted Average	**4%**	**8%**	**3%**	**<0.1%**	**54%**	**<1%**	**31%**

Table 10: Portfolio Percentages 2024 RPS Mix for ESPs
Data Source: ESPs' Annual RPS Compliance Reports (August 2025)

As Table 10 above 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, and two ESPs procured solely from these technologies. ESPs continued the trend of solar making up over half of contributions, and wind slightly less than a third.

Contracted Renewable Capacity

Since 2003, the three IOUs have contracted for over 20,049 MW of renewable capacity[39] under the RPS program. The CPUC reviews all new RPS capacity addition contracts 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 below includes both in-state and out-of-state facilities that have contracted with the IOUs and have come online between 2003 and 2024. Most of the new facilities procured for the RPS program are located in the state. Approximately 797 additional MW of renewables contracted by the IOUs are scheduled to come online in 2025.

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

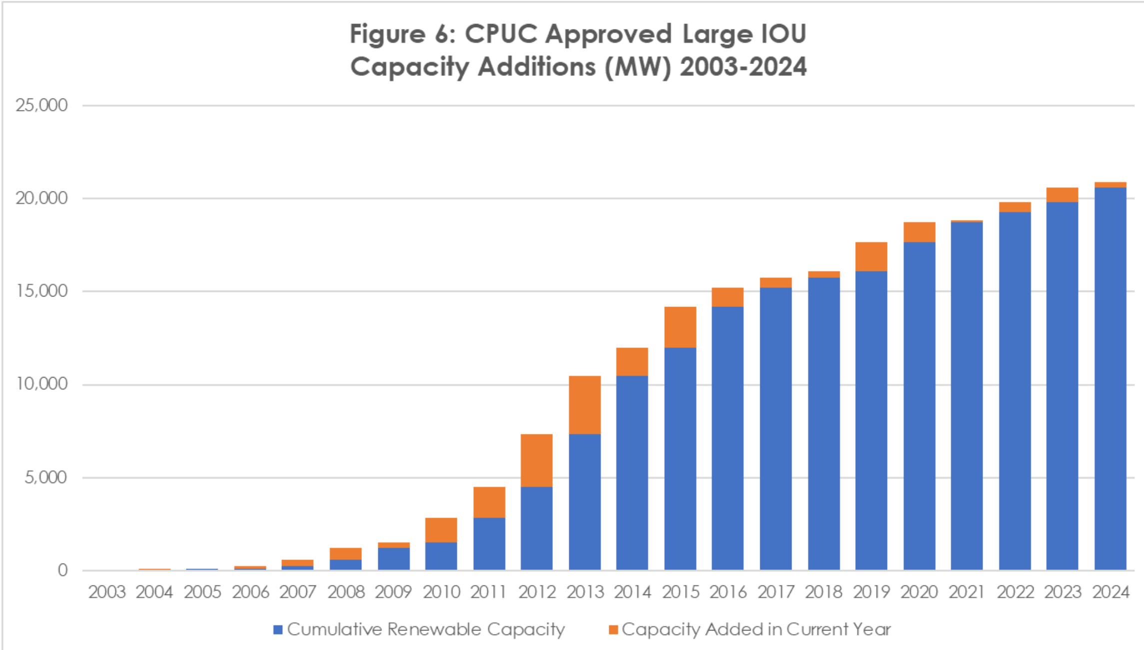

Figure 6: CPUC Approved IOU Capacity Additions (MW) 2003-2024
Data Source: CPUC RPS Database, September 2025

RPS Procurement Costs

The CPUC issues a Report on RPS Costs and Cost Savings (Padilla Report) each year pursuant to California Public Utilities Code § 913.3 to summarize the RPS program procurement costs. The CPUC collects various RPS cost and pricing data to analyze, evaluate and summarize RPS costs and trends.[40]

For information on all utility programs and activities currently recovered in retail rates, see the annual *California Electric and Gas Utility Costs Report: AB 67 Annual Report to the Governor and Legislature*, pursuant to California Public Utilities Code § 913.[41]

The IOUs use competitive procurement mechanisms and a Least-Cost Best-Fit[42] approach to procure renewable resources that provide the most value to their customers. The CPUC has established[43] an IRP proceeding to identify the most cost-effective portfolio of resources to inform future procurement activities, and the IOUs have adopted the Least-Cost, Best-Fit approach as a decision-making framework for their procurement activities in support of their IRP plans.

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

40 *See* CPUC RPS Reports page: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/energy-reports-and-whitepapers/rps-reports-and-data.
41 *See* CPUC AB 67 Annual Cost Report available at https://www.cpuc.ca.gov/ab67report.
42 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.
43 For more information on the IRP proceeding (R.25-06-019), visit https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning.

7 below, in real dollars, 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.

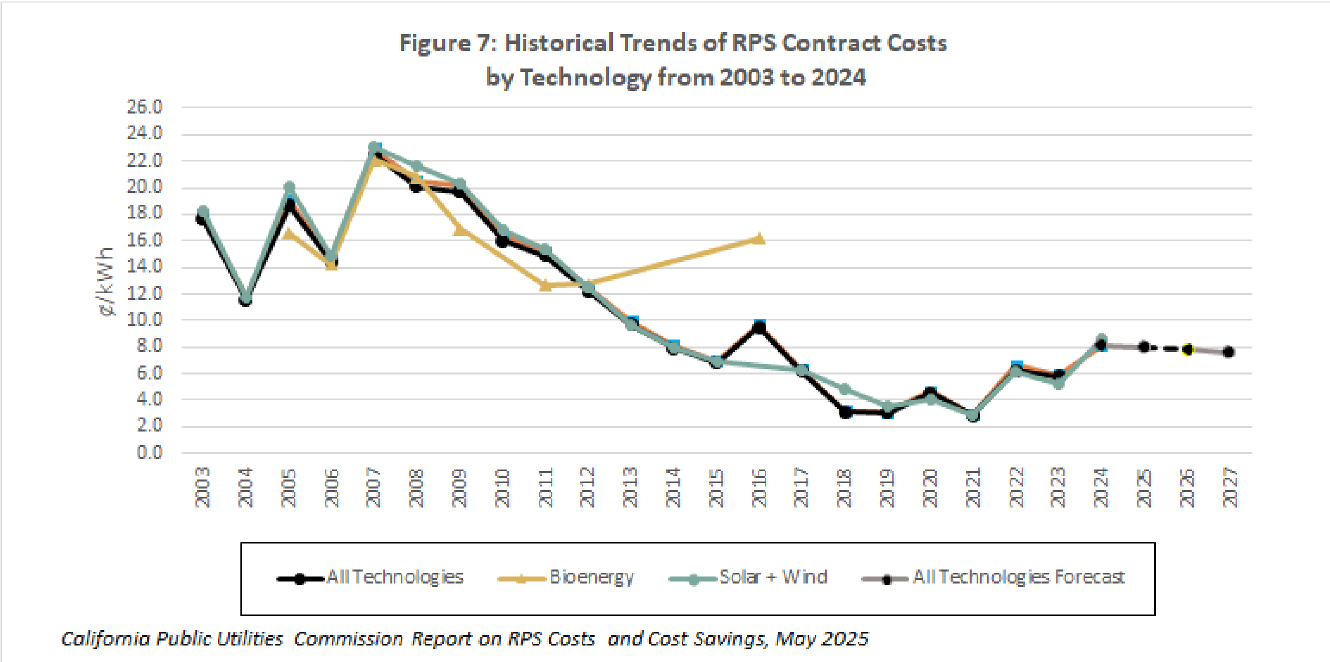

Figure 7: Historical Trends of RPS Contract Costs by Technology from 2003 to 2024
Data Source: CPUC RPS Database, September 2025

Figure 7[44] shows that RPS contract prices, in real dollars, decreased on average by 5.6 percent annually between 2007 and 2024 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 historic contract price trends for the RPS program seen in Figure 7 above show that executed contract prices peaked in 2007 and have been generally falling for RPS-eligible resources, but they have risen slightly (in inflation-adjusted dollars) over the last few years. The average price of IOU, CCA, and ESP RPS contracts executed in 2024 that were greater than 3.0 MW continues this recent trend of increasing prices. Specifically, the average price in 2024 was 8.1¢/kWh compared to 5.8 ¢/kWh in real-dollar value in 2023. This 37.3 percent increase was likely driven by an increased demand to meet the end of RPS Compliance Period 2021-2024 requirements, uncertainty of supply chain constraints, potential impact of increasing inflation rates, and higher interest rates. For more information on the costs of the RPS program, see the CPUC's 2025 Annual Report on RPS Costs and Cost Savings (Padilla Report).[45]

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44 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.

45 *See* https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/energy/rps/2025/2025-padilla-report.pdf.

Renewable Procurement and Project Development

This chapter uses the most current procurement and contracting data available as of September 2025 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 2024, though their RPS-eligible procurement primarily occurred through solicitations motivated by IRP obligations. SCE contracted RPS-eligible resources throughout 2024 from its multi-phase IRP Mid-term Reliability (MTR) solicitation, and launched its 2024 Clean Energy solicitation to procure new RPS-eligible resources. PG&E executed four contracts for RPS-eligible resources from its MTR solicitation, totaling 1,025 MW of nameplate capacity.

Table 11: New Renewables Projects with IOU Contracts COD 2025-2028					
IOU	**Technology**	**Capacity (MW)**	**County/Location**	**Contract Term (Years)**	**COD**
Pacific Gas and Electric	Solar PV	150	Kern, CA	15	2025
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	Geothermal	336	Millard, UT	15	2028
Southern California Edison	Solar PV	20	Kern, CA	12	2025
Southern California Edison	Geothermal	62	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
Southern California Edison	Solar PV	100	La Paz, AZ	15	2026
Southern California Edison	Solar PV	225	La Paz, AZ	15	2026
Southern California Edison	Solar PV	167	La Paz, AZ	15	2026
Southern California Edison	Solar PV	167	La Paz, AZ	15	2026
Southern California Edison	Solar PV	167	La Paz, AZ	15	2026
San Diego Gas & Electric	Solar PV	113.5	Mendota, CA	15	2025
San Diego Gas & Electric	Solar PV	50	Pahrump, NV	15	2027
San Diego Gas & Electric	Hybrid	20	San Diego, CA	12	2027
Total MW		**2,682**			

Table 11: New Renewables Projects with IOU Contracts COD 2025-2028
Data Source: IOUs' Draft RPS Procurement Plans (July 2025), IOUs' Annual RPS Compliance Reports (August 2025)

Renewable Energy Credit (REC) Sales

Due to the IOUs' forecasted excess RPS procurement from banked RECs, the CPUC authorized the IOUs to hold REC sales solicitations since 2019 to sell RPS energy from their portfolios.[46] The IOUs' long RPS position is a result of forecasted excess RPS procurement, relative to RPS annual procurement targets and customer load departure due to CCA load growth. 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 since 2019, including in 2024, and have requested CPUC approval to conduct additional REC sales solicitations in 2025. 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 (see Program Activities section for more details on VAMO).

In 2024, PG&E executed a total of nine REC sales contracts. Table 12 below shows REC sales solicitation summaries by IOU.

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**
2024	9	2, 310	**-**	**-**	**-**	**-**	**9**	**2, 310**

Table 12: IOU REC Sales Contracts Approved by the CPUC
Data Source: CPUC RPS Database, September 2025

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 56,000 GWh of RPS energy from their portfolios from 2021 to 2024 and will sell additional RPS energy in 2025 and 2026 from authorized REC sales and approved Market Offer contracts.

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

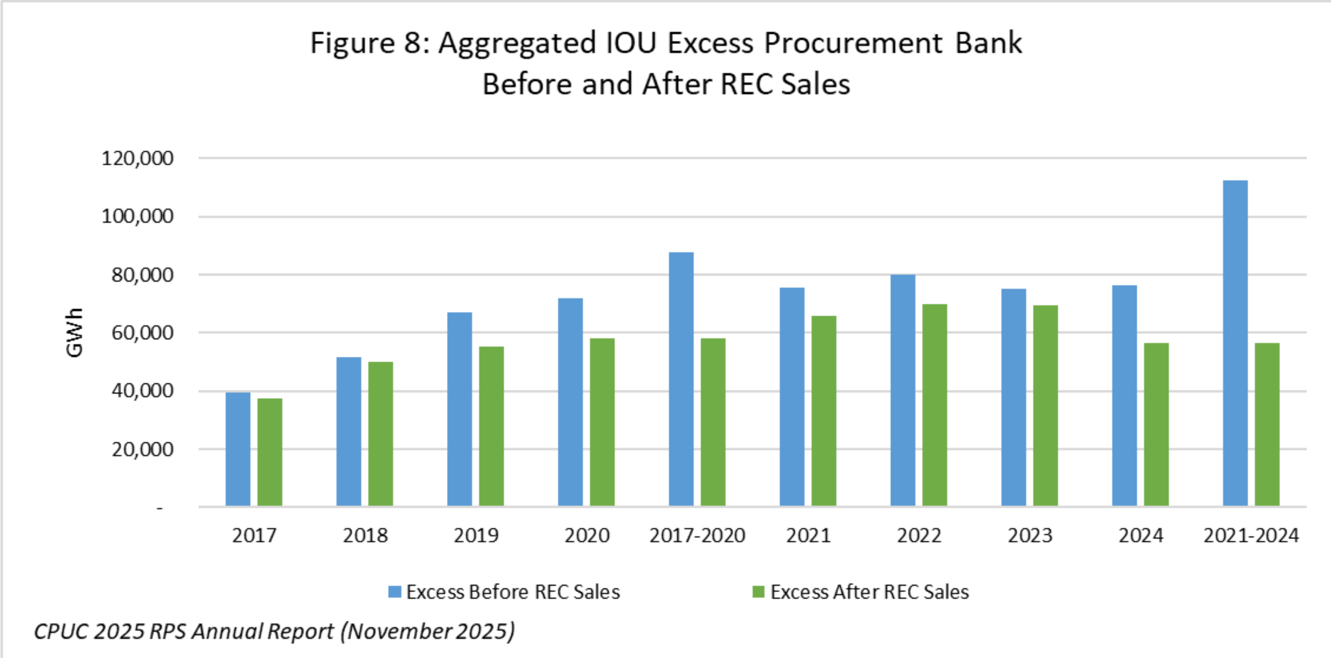

Figure 8: Aggregated IOU Excess Procurement Bank Before and After REC Sales
Data Source: IOUs' 2025 Draft Procurement Plans, Renewable Net Short calculations

Small and Multi-Jurisdictional Utilities (SMJUs)

Liberty did not execute any contracts to procure eligible renewable energy as part of its 2024 RPS Procurement Plan. BVES submitted an application (A.24-05-020) to the CPUC 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 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. Additionally, in 2025, the CPUC approved BVES' purchase of 15,000 unbundled RECs.[47] On August 22, 2024, the CPUC approved PacifiCorp's procurement of long-term unbundled renewable energy credits via Resolution E-5343. This Resolution approved PacifiCorp's RECs purchase with 3Degrees Group, Inc. for 40,000 unbundled RECs per year.

The SMJUs are allowed to 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 drop off after 2024, and they will need to increase procurement if they are to meet Compliance Period 2025-2027 requirements.

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

47 BVES AL 520-E.

Community Choice Aggregators (CCAs)

To date, 16 CCAs have executed long-term contracts with new utility-scale[48] renewable projects that are in development. The data in the tables below includes 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 2025 and 2026. Of the contracts listed, about 93 percent are for new solar PV resources, many of which are hybrid or are co-located with storage.

Table 13: New California Renewables Projects Contracted by CCAs with COD in 2025–2026					
CCA	**Technology**	**Capacity (MW)**	**County/ Location**	**Contract Term (Years)**	**COD**
Ava Community Energy	Solar PV	200	Fresno	20	2026
Central Coast Community Energy	Hybrid	120	Kern	20	2026
Central Coast Community Energy	Hybrid	20	Tulare	15	2026
Central Coast Community Energy	Hybrid	62	Fresno	15	2025
CleanPowerSF	Wind	148	Merced	20	2026
CleanPowerSF	Solar PV	75	Alameda	25	2026
Marin Clean Energy	Hybrid	100	Kern	15	2025
San Diego Community Power	Solar PV	90	San Diego	20	2026
San Diego Community Power	Solar PV	160	San Bernadino	20	2026
San Jose Clean Energy	Solar PV	105	Kern	15	2026
San Jose Clean Energy	Solar PV	48	Kern	15	2025
Silicon Valley Clean Energy	Hybrid	80	Kern	20	2026
Silicon Valley Clean Energy	Hybrid	20	Tulare	15	2026
Silicon Valley Clean Energy	Hybrid	63	Fresno	15	2025
Sonoma Clean Power Authority	Solar PV	60	Kern	10	2025
Total MW		**1,351**			

Table 13: New California Renewables Projects Contracted by CCAs with COD in 2025–2026
Data Source: CCAs' Draft RPS Procurement Plans (July 2025), CCAs' Annual RPS Compliance Reports (August 2025)

The CCAs also contracted with new renewable projects with commercial online dates further into the future and located outside of California. The tables below list additional in-state renewables contracts with CODs in 2027 and 2028 and out-of-state renewables contracts with CODs in 2025-2027. These contracts can satisfy both RPS and IRP procurement obligations.

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

Table 14: New California Renewables Projects Contracted by CCAs with COD in 2027-2028					
CCA	**Technology**	**Capacity (MW)**	**County Location**	**Contract Term (Years)**	**COD**
Ava Community Energy Authority	Solar PV	75.0	Riverside	10	2027
Ava Community Energy Authority	Solar PV	75.0	Riverside	10	2027
Ava Community Energy Authority	Solar PV	37.5	Merced	20	2027
Ava Community Energy Authority	Solar PV	100.0	Imperial	15	2027
Ava Community Energy Authority	Solar PV	70.0	Fresno	20	2028
Central Coast Community Energy	Hybrid	70.0	Kern	10	2027
CleanPowerSF	Solar PV	50.0	Riverside	10	2027
Orange County Power Authority	Solar PV	90.0	Riverside	20	2027
Peninsula Clean Energy	Wind	80.8	Alameda	4	2027
Pioneer Community Energy	Solar PV	210.0	Kern	15	2027
San Diego Community Power	Solar PV	440.0	Kern	15	2027
San Jose Clean Energy	Solar PV	37.5	Merced	20	2027
San Jose Clean Energy	Geothermal	24.5	Imperial	20	2028
Silicon Valley Clean Energy	Solar PV	120.0	Riverside	15	2027
Total MW		**1,480.3**			

Table 14: New California Renewables Projects Contracted by CCAs with COD in 2027-2028
Data Source: CCAs' RPS Draft Procurement Plans (July 2025), CCAs' Annual RPS Compliance Reports (August 2025)

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 2025–2027					
CCA	**Technology**	**Capacity (MW)**	**County Location**	**Contract Term (Years)**	**COD**
Ava Community Energy Authority	Wind	250.0	Lincoln, NM	15	2026
Ava Community Energy Authority	Solar PV	42.5	Maricopa, AZ	20	2026
Central Coast Community Energy	Wind	205.0	Lincoln, Torrance, San Miguel, NM	15	2026
Peninsula Clean Energy	Wind	220.0	Lincoln, NM	15	2026
San Diego Community Power	Solar PV	35.0	Clark, NV	20	2027
San Diego Community Power	Solar PV	150.0	Torrance, NM	15	2026
San Jose Clean Energy	Solar PV	42.5	Maricopa, AZ	20	2026
Silicon Valley Clean Energy	Wind	100.0	Lincoln, Torrance, San Miguel, NM	15	2026
Silicon Valley Clean Energy	Solar PV	50.0	La Paz, AZ	10	2025
Sonoma Clean Power Authority	Wind	100.0	Torrance, NM	15	2026
Total MW		**1,195.0**			

Table 15: New Out-of-State Renewables Projects Contracted by CCAs with COD 2025–2027
Data Source: CCAs' RPS Draft Procurement Plans (July 2025), CCAs' Annual RPS Compliance Reports (August 2025)

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 with 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. Many of these contracts can be utilized to satisfy both RPS and IRP procurement obligations.

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

Table 16: New Long-term Renewables Projects with ESP Contracts					
ESP	**Technology**	**Capacity (MW)**	**County Location**	**Contract Term (Years)**	**COD**
Shell Energy North America	Wind	260	Torrance (NM)	15	2026
Shell Energy North America	Geothermal	31	Beaver (UT)	20	2026
The Regents of the University of California	Solar PV	45	Kern	15	2025
The Regents of the University of California	Wind	85	Torrance (NM)	15	2026
Total MW		**421**			

Table 16: New Long-term Renewables Projects with ESP Contracts
Data Source: ESPs' Draft RPS Procurement Plans (July 2025) and ESPs' Annual RPS Compliance Reports (August 2025)

Projects in Disadvantaged Communities

SB 350 directs the CPUC to consider within its programs and policymaking the 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.[49] These burdens include poverty, high unemployment, air and water pollution, and the presence of hazardous wastes, as well as a 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)[50], the Electric Vehicle Charging Infrastructure programs[51], the Modified Green Tariff Program[52], the Solar on Multifamily Affordable Housing (SOMAH) Program[53], the Disadvantaged Communities - Single-family Solar Homes (DAC-SASH) Program[54], and the Disadvantaged Communities Green Tariff (DAC-GT) Program.[55] 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.

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

50 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.

51 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.

52 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.

53 Solar on Multifamily Affordable Housing (SOMAH) program provides incentives for solar energy photovoltaic systems for multifamily affordable housing. Those interested in learning more about the SOMAH Program should visit https://www.cpuc.ca.gov/somah/.

54 The Disadvantaged Communities – Single-family Solar Homes (DAC-SASH) program, modeled after the Single-family Affordable Solar Homes (SASH) Program, provides financial incentives for the installation of rooftop solar generating systems. For more information, go to https://www.cpuc.ca.gov/solarindacs.

55 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.

Indirect benefits of renewable facilities include increased local spending from facility employees and increased public health outcomes associated with low- or zero- 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.[56] If the facility is located outside of California, the Climate and Economic Justice Screening Tool (CEJST)[57] can be used to identify DACs that are marginalized by underinvestment and overburdened by pollution.[58]

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 descriptions of solicitations and procurement preferences within RPS Procurement Plans. Further they are required to 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[59] and how their methodologies address state policies related to equity, the environment, and economic development. Most recently, in their 2025 Draft RPS Procurement Plans[60], retail sellers described how they consider additional qualitative criteria to determine if projects are a fit for their needs and existing portfolios. 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. 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 of three SMJUs, 19 out of 24 CCAs, and ten out of ten ESPs described considerations for DACs within their Draft 2025 RPS Procurement Plans.

56 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.)

57 The original tool used in this assessment is no longer available due to an Executive Order rescinding President Biden's Executive Order 14008, which established the Justice40 Initiative and required Council on Environmental Quality to create a Climate & Economic Justice Screening Tool (CEJST). The CEJST Tool is now accessible on the Center for Neighborhood Technology's website, which can be found at: https://justice40.cnt.org/.

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

59 *See* Public Utilities Code Section 399.13(a)(8).

60 *See* Section 10 of Draft 2025 RPS Plans for retail sellers for more information on their bid selection methodologies.

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- formerly EDF)	ESP	Among other qualitative attributes considered during project selection, 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 to 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 to 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 states that all future projects are screened for their location in DACs, and it will continue to give preference to those that meet this criterion.
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	CPSF solicitation protocol does not currently include specific consideration for DACs. However, 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 (LCE)	CCA	Requires that projects located in DACs provide insight into the emissions, workforce, and economic impacts that could be imposed on the surrounding DAC.
Liberty Utilities CalPeco (LIBU)	SMJU	LIBU notes that while it seeks to provide environmental and economic benefits to DACs, Section 399.13(a)(8) applies only to facilities in California, and the bulk of supplies are and will continue to be sourced from Nevada.
Marin Clean Energy (MCE)	CCA	Evaluates offers according to their potential economic benefits and environmental impacts to nearby communities with high levels of poverty, unemployment, and pollution.
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, 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	PPG notes that, to the extent available, preference is given to projects that provide environmental and economic benefits to DACs.
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 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, but it recognizes the importance of considering DACs.
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	Incorporates DAC status into the confidential scoring rubric used to evaluate proposals and recognizes the importance of considering DACs in its procurement processes.
Valley Clean Energy Alliance (VCEA)	CCA	There is no mention of consideration for DACs in the project selection criteria. VCEA says it will consider equity and impacts on DACs in future solicitations.

Table 17: DAC Considerations in LCBF Methodologies
Source: 2025 Draft RPS Procurement Plans

The following map uses data from the 2025 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 2025-2031)[61]

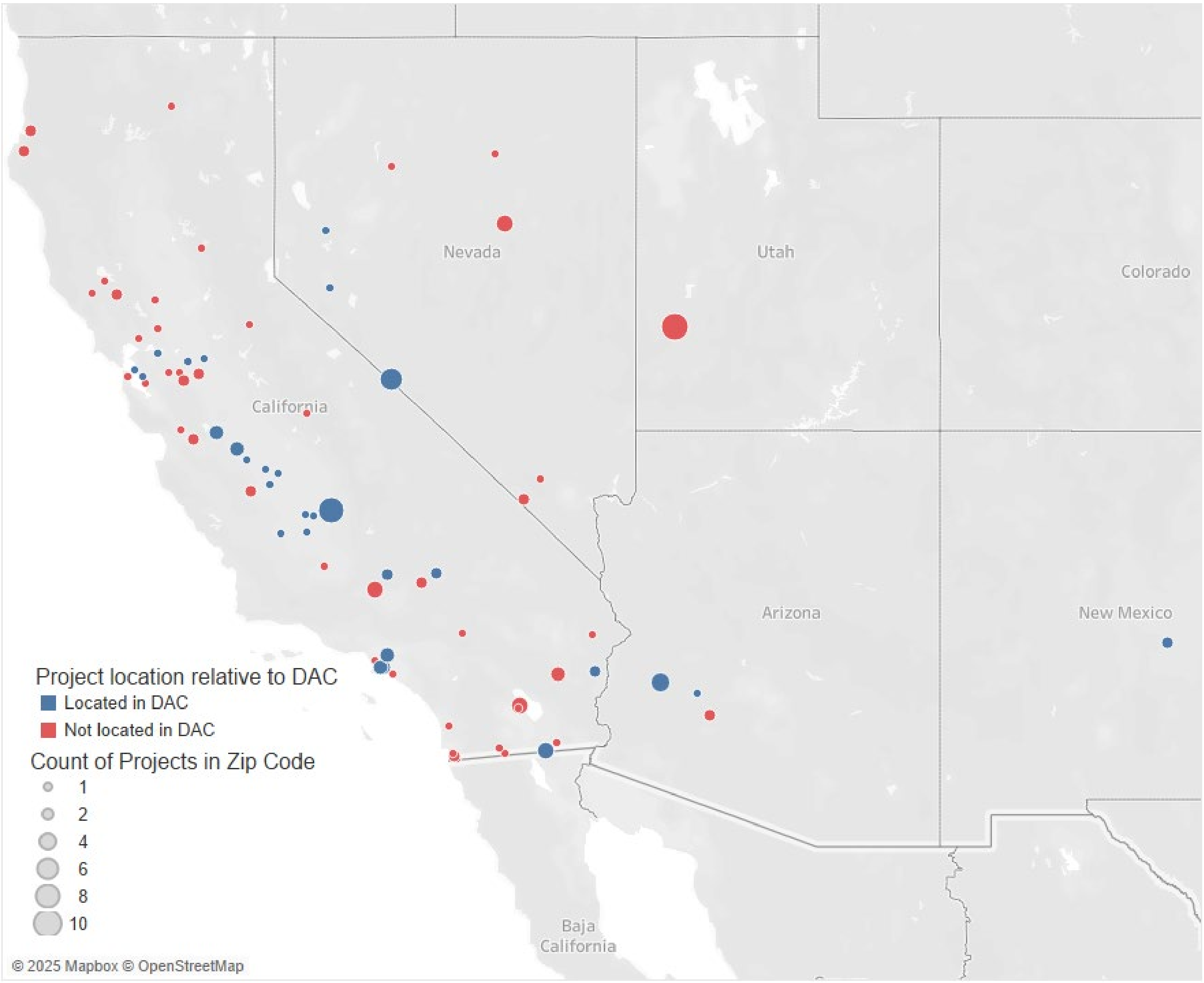

Figure 9: New RPS Projects Contracted by LSEs
Data Source: Project Development Status Update data from the 2025 Draft Procurement Plans

61 Excludes projects with "Multiple" or "Various" locations, and projects identified as being in a community that was determined to be "Partially" disadvantaged by CEJST were designated "Not located in DAC". 103 of the projects included on this map are in California, while 38 projects are out-of-state.

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

Table 18: New RPS Projects in DACs with CODs in 2025-2031[62]		
LSE Type	**Projects in DACs**	**New Projects**
CCAs	54	116
ESPs	0	2
IOUs	11	22
SMJUs	0	1
Total[63]	**65**	**141**

Table 18: New RPS Projects in DACs
Data Source: Project Development Status Update data from the 2025 Draft Procurement Plans

Table 19: New RPS Projects in DACs by Resource Type with CODs in 2025-2031[64]			
Resource Type	**Projects in DACs**	**(%) Projects in DACs**	**New Projects**
Biomass	0	0%	5
Digester Gas	2	100%	2
Geothermal	14	37%	38
Solar - Battery Storage	19	58%	33
Solar PV	28	50%	56
Storage	0	0%	3
Wind	2	50%	4
Total	**65**	**46%** (Average)	**141**

Table 19: New RPS Projects in DACs by Resource Type
Data Source: Project Development Status Update data from the 2025 Draft Procurement Plans

62 Excludes projects with ”Multiple” or ”Various” locations, and projects identified as ”Partially” in DAC by CEJST were designated ”Not Located in DAC”.

63 Total number of RPS Projects does not include those categorized as Multiple or Various locations.

64 Excludes projects with ”Multiple” or ”Various” locations, and projects identified by CEJST as “Partially“ in DAC were designated “Not Located in DAC“, one project that did not have a COD was also excluded.

RPS Program Activities

This chapter identifies and discusses key 2024 and 2025 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.

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.[65] Through the IRP process, the CPUC requires procurement from new electricity resources to meet reliability and increasingly stringent GHG targets to achieve the SB 100 goal of 100 percent of retail electricity sales being met with renewable and zero-carbon resources by 2045.[66] Activities in the IRP proceeding are complementary to RPS procurement activities and support resource planning for the electric sector, including transmission planning.

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.[67] 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.

In April 2025, the CPUC issued a Staff Proposal for the Reliable and Clean Power Procurement Program (RCPPP) in the IRP proceeding.[68] The goal of RCPPP is to provide retail sellers with a more predictable regulatory framework to procure their share of the resources needed to meet electric system reliability and GHG emission reduction goals at least cost. While the RCPPP Staff Proposal is divided into two components for reliability purposes and GHG emissions reduction purposes, the proposed GHG reductions component of RCPPP establishes a Clean Energy Standard (CES) for retail sellers that heavily mirrors and complements the RPS program. For example, the current CES proposal for RCPPP establishes a backward-looking compliance process with multi-year compliance periods that is similar to and aligned with RPS compliance processes. Like RPS targets, the CES target would be established as an annual clean energy target as a percentage of retail sales. The CES mirrors the use of Renewable Energy Credits (REC) for RPS compliance by creating Zero Emission Credits (ZEC) as the metric for CES compliance. Further, because RPS-eligible resources are eligible for RCPPP and because IRP modeling assumes that retail sellers must meet the requirement for 60 percent RPS by 2030, both ZECs and RECs could be used for CES

65 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.

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

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

68 For more information on RCPPP, visit https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/the-reliable-and-clean-power-procurement-program.

compliance. Finally, RCPPP contemplates possibly incorporating and expanding the RPS Procurement Plan and Compliance Report filing requirements. The CPUC received comments from stakeholders on the proposal and is currently considering them in the IRP proceeding.

Additional future IRP and RPS alignment may 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 will be undertaken in the RPS proceeding, in coordination with the IRP proceeding, on an ongoing basis.[69]

Voluntary Allocation and Market Offer Process for RPS Portfolio Optimization

On May 24, 2021, the CPUC issued 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.

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 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 a Voluntary Allocation process 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.[70] The CPUC approved the Voluntary Allocations on November 3, 2022. Voluntary Allocations did not occur in 2024 or 2025 because in January 2024, the CPUC approved the IOUs' unanimous request not to conduct future VAMO processes, and no retail sellers have been newly formed.

69 *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.

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

Market Offers

After the Voluntary Allocation process, the IOUs solicited Market Offers for all remaining PCIA-eligible RPS resources. 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 were required to offer a minimum of 35 percent of their respective remaining volumes as long-term product, and the remainder of their respective remaining volumes 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[71] and Long-term Market Offer contracts were approved in November and December 2023.[72] A total of 21 Market Offer contracts were executed, representing 46.4 million MWh. The IOUs continued to offer any remaining volumes in 2024 via sales solicitations.

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) have engaged with counterparties for contract termination, assignment, or modification as a result of their 2023 RFI solicitations. PG&E executed contract termination agreements for two facilities: Ivanpah Solar Electric Generating Station Units 1 and 3. PG&E filed an Advice Letter on January 17, 2025, seeking approval of the termination agreements, which the CPUC is currently considering[73.] SDG&E reports that it is still evaluating responses from its 2023 RFI, and SCE reports that neither of its RFIs has yielded any results.

As in their 2023 RPS Procurement Plans, none of the IOUs proposed additional RFIs in their 2024 or draft 2025 RPS Procurement Plans.

Implementation of AB 843 (2021)

Assembly Bill (AB) 843 (Aguiar-Curry, Chapter 234, Statutes of 2021) authorizes CCAs to administer Bioenergy Market Adjusting Tariff (BioMAT) programs equivalent to those 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. 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.

On November 30, 2023, the CPUC adopted D.23-11-084, which sets rules to enable CCAs to administer their own BioMAT programs, as authorized by AB 843. On January 29, 2024, Central Coast Community

71 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.

72 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.

73 PG&E Advice Letter 7485-E.

Energy, Orange County Power Authority, Pioneer Community Energy, and Redwood Coast Energy jointly submitted a Joint Tier 2 Advice Letter requesting Energy Division approval of a suite of BioMAT program implementation documents. Currently, Central Coast Community Energy, Orange County Power Authority, Pioneer Community Energy, and Redwood Coast Energy Authority are each offering BioMAT contracts that have active BioMAT websites, but as of October 2025, only Central Coast Community (3CE) has executed a BioMAT contract. The contract is with a Category 2 (other agriculture) project, Tracy Renewable Energy LLC/Tracy Renewable Power Plant, and has a contract capacity of 3 MW and a commercial operation date of February 26, 2027.[74]

Additional Mandated RPS Procurement Activities

In addition to procuring to meet RPS requirements, the IOUs are required to procure renewable energy through various mandated programs that encourage the development of smaller renewable energy facilities. SMJUs, CCAs, and ESPs are not required to procure RPS resources through these mandated programs.

Feed-in Tariff Programs

California's Feed-in Tariff (FIT) program is a policy mechanism designed to accelerate investment in small 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 were established by the California Legislature and have been modified numerous times since their inception.

ReMAT

ReMAT[75] is a FIT program established by SB 32 (Negrete McLeod, Chapter 328, Statutes of 2009) and SB 2 and commenced offering fixed-price standard contracts in 2013. Small RPS-eligible facilities generating up to 3 MW[76] are eligible for the ReMAT program. Under the ReMAT program, the small generators sell renewable electricity to utilities at an administratively-set fixed price pursuant to ReMAT's standard terms and conditions for terms of 10 to 20 years. In June of 2025, the CPUC approved an annual ReMAT pricing update per the methodology adopted in D.20-10-005.[77]

74 *See* https://cca-biomat.accionpower.com/_cpuc_2301/home.asp.

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

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

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

Each IOU has capacity amounts allocated to it based on its proportionate share of statewide electric load served. Table 20 below provides an overview of the progress from the program's inception in 2013 to the present that each IOU has made toward its ReMAT allocation[78]. It should be noted that contracts procured under the CPUC's original FIT program, prior to ReMAT's creation in 2013, count toward an IOU's procured total of their allocation of the mandated 493.6 MW capacity. The "ReMAT Remaining (MW)" column in Table 20 accounts for contracts previously procured under the original FIT program and ReMAT contracts in determining the IOUs' remaining ReMAT procurement amounts. The ReMAT program has approximately 199 MW of capacity left for procurement.

Table 20: IOU ReMAT Procurement			
IOU	**Procurement Mandate[79]**	**ReMAT Contracted (MW)**	**ReMAT Remaining (MW)[80]**
PG&E	218.8	50.14	102.71
SCE	226	47.81	75.69
SDG&E	48.8	7.58	20.91
Total	**493.6**	**105.53**	**199.31**

Table 20: IOU ReMAT Procurement
Data Source: PG&E, SCE, and SDG&E ReMAT Program web pages (August 2025)

ReMAT is divided into three product categories: As-Available Non-Peaking, As-Available Peaking, and Baseload.[81] Each IOU has a specific capacity allocated to each of the three categories, and historically, As-Available Peaking has been the most procured ReMAT category. Per D.21-12-032, when an IOU reaches a de minimis threshold of 0.99 MW within one of the three product categories, the IOU shall submit a Tier 2 advice letter to combine that product category with the ReMAT product category that has the most remaining capacity left to procure. In 2025, SCE was the first IOU to request to combine product categories with Advice Letter 5583-E, where SCE requested to combine the As-Available Peaking and Baseload product categories, as the As-Available Peaking category had dropped below the 0.99 de minimis threshold. Advice Letter 5583-E was approved on August 14, 2025.

BioMAT

BioMAT is a FIT program established by SB 1122 (Rubio, Chapter 612, Statues of 2012) for small-scale bioenergy projects.[82] 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

78 PUC § 399.20 establishes a program capacity.

79 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.

80 Remaining amount accounts for contracting done via the original FIT program as well as contracting via ReMAT.

81 See more about ReMAT product categories here: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-procurement-programs/renewable-market-adjusting-tariff.

82 Modifications were made to the program pursuant to AB 1923 (Wood, Chapter 663, Statues of 2016), which increased eligible project size to 5 MW. Fuel use eligibility changes were also made pursuant to SB 840 (Chapter, 341, Statutes of 2016, Ch. 341) and following a program review numerous other changes were made in 2020. More recently AB 843 expanded the program to CCAs that wish to participate.

implemented in 2014[83] and uses a standard contract and a market-based mechanism to arrive at the offered program contract price. AB 843 authorized CCAs to also administer their own BioMAT programs and was implemented in 2024. See the above *Implementation of AB 843* section for more information on AB 843. Program costs are allocated to all IOU, CCA, and ESP customers.[84]

Table 21 shows the BioMAT targets and capacity (MW) procured over the life of the program by the three IOUs.[85] As of September 2025, Central Coast Community Energy has signed one BioMAT contract.

Table 21: BioMAT Mandated Allocation by Category

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	30.82	59.18	22	187.72 (Dairy) 183.72 (Other Agriculture)
Sustainable Forest Management	50	32.48	17.52	14	199.72
Total	**250**	**88.12**	**161.88**	**46**	**-**

Table 21: BioMAT Mandated Allocation by IOU
Data Source: CPUC Database (September 2025)

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 21 above.

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 released in late 2025.

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83 *See* D.14-12-081.
84 Per SB 859 (Chapter 368, Statutes 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.
85 While several CCAs began offering BioMAT contracts in 2024, none have been executed to date.

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.[86] Subsequently, SB 859 (Chapter 368, Statutes of 2016)[87] directed additional BioRAM procurement from the IOUs, resulting in the procurement order of 146 MWs of bioenergy from High Hazard Zones (HHZ)[88] fuel. SB 901 (Dodd, Chapter 626, Statutes of 2018) further amended the BioRAM program to add program flexibility and extend certain biomass contracts by five years.[89] SB 1109 (Caballero, Chapter 364, Statutes of 2022) further extended certain eligible biomass contracts by a minimum of five years but not to exceed fifteen years. Additionally, SB 1109 added the requirement that 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, Statutes of 2024) amended the BioRAM program by extending the IOU's deadline to procure their proportionate share of the 125 MW BioRAM contracts by July 1, 2025. Additionally, it required the IOUs to seek contract extensions, or new contracts, of at least 5 years, if they expire before December 31, 2028. The CPUC is implementing the program revisions through Resolution E-5376, approved by the Commission in April 2025. The table below lists the IOUs' active BioRAM contracts.

Table 22: IOU BioRAM Contract Summary[90]

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 22: IOU BioRAM Contract Summary
Data Source: CPUC RPS Database, September 2025

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 and measure the amount of HHZ fuel that BioRAM facilities utilize on a calendar year basis. In 2025, the IOUs completed independent audits on each facility's 2024 HHZ fuel usage.

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86 *See* https://www.ca.gov/archive/gov39/wp-content/uploads/2017/09/10.30.15_Tree_Mortality_State_of_Emergency.pdf.
87 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.
88 For more information on high-hazard zone areas, see CALFIRE's website: https://frap.fire.ca.gov/mapping/maps/.
89 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.
90 SCE's BioRAM contract with Rio Bravo Fresno for 24 MW of capacity ended in September 2022.

HHZ fuel usage data for the current IOU-contracted BioRAM facilities is aggregated in Table 23 below.

Table 23: HHZ Forest Fuel Usage from BioRAM Contracts				
Year	**BioRAM HHZ % Requirements**	**Average % of Total Biomass Fuel from HHZ Fuel**	**Total HHZ Delivered (BDT)** [91]	**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%[92]	84.0%	1,557,050	2,505,641
2020	60% and 80%	79.0%	862,147	3,367,788
2021	60% and 80%	82.5%	844,527	4,212,315
2022	60% and 80%	84.0%	951,677	5,136,208
2023	60% and 80%	82.0%	968,355	6,104,563
2024	60% and 80%	84.4%	979,577	7,084,140

Table 23: 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 other 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.

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), a division of the Western Electricity Coordinating Council (WECC) to issue and track RECs. In 2022, WREGIS implemented a system overhaul that impaired its ability to issue RECs. The CEC and CPUC monitored WREGIS' corrective efforts throughout 2023 and 2024, with the issues resolved in 2024. WREGIS is now moving to replace the new system, which the CEC and CPUC are again monitoring, and providing constructive feedback as appropriate. See the Compliance and Enforcement Section and Appendix B for more details on RPS compliance and enforcement.

91 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.

92 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.

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 the United States Forest Service (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 monthly and quarterly meetings with other State and Federal agencies that support forest biomass utilization.

Of specific concern is the high cost of BioMAT and BioRAM procurement. In comparison to RPS resources, in 2024, the average RPS contract price for all retail sellers was approximately 8.1 cents per kilowatt-hour (kWh), while BioMAT prices ranged from 12.77 to 19.97 cents per kWh.[93]

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 needs from offshore wind. The CPUC supports offshore wind development for its potential clean energy and reliability benefits; however the high cost of development of offshore wind has been noted by the CPUC's IRP planning processes. The CPUC considers offshore wind in its IRP process, where the resource is available for potential selection in the IRP capacity expansion model and where the AB 1373 (2023, Garcia) central procurement process and related implementation is being considered. 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.[94] Such a decrease would be significant given that the National Renewable Energy Lab estimated the current levelized cost of energy to be \$145/MWh.[95] 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.[96]

93 2025 Padilla Report at 22-23: https://www.cpuc.ca.gov/RPS_Reports_Data/.
94 https://www.energy.gov/eere/wind/floating-offshore-wind-shot.
95 Stehly, Tyler and Patrick Duff. 2022 Cost of Wind Energy Review. https://docs.nrel.gov/docs/fy24osti/88335.pdf.
96 https://www.boem.gov/renewable-energy/state-activities/california.

On July 10, 2024, the CEC adopted a final report[97] 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 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. On October 7, 2023, Governor Newsom signed AB 1373 (Garcia, Chapter 367, Statutes of 2023), which permits the state to sign long-term contracts for the purchase of electricity from offshore wind facilities, in coordination with the CPUC's IRP process. 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 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. 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.

However, despite the progress discussed above for the development of offshore wind in California, in January 2025, a Presidential Memorandum from the Trump-Vance Administration halted federal leasing for wind energy on the Outer Continental Shelf and paused permitting of both offshore and onshore wind on federal lands for further review.[98] In August 2025, the U.S. Department of Transportation withdrew federal funding for port infrastructure upgrades related to the development of offshore wind.[99] This resulted in the withdrawal of $427 million for the Humboldt Bay Offshore Wind Heavy Lift Marine Terminal Project, which is one of three California ports identified as suitable for offshore wind development operations.

Hydrogen

The CPUC and other state agencies remain deeply engaged in hydrogen strategy. Pursuant to SB 1075 (Skinner, 2022), the CARB, CPUC, and CEC are coordinating a comprehensive hydrogen report, covering deployment, development, and cross-sectoral use as central elements of climate and energy goals.[100]

The CPUC's ongoing role encompasses regulatory oversight of hydrogen development and production for electricity generation, long-term energy storage, and hard-to-electrify sectors, provided that only clean hydrogen is used for electricity production. Under the state's RPS, hydrogen-to-electricity conversion facilities are eligible for RPS certification if their fuel cells use hydrogen derived from non-fossil fuels produced via eligible renewable energy sources. With the enactment of AB 1921 (Papan, 2024), fuel cells

97 *See* CEC's Final Commission Report: Assembly Bill 525 Offshore Wind Energy Strategic Plan, June 2024. The three volumes of this report can be found at: https://www.energy.ca.gov/data-reports/reports/ab-525-reports-offshore-renewable-energy.

98 https://www.whitehouse.gov/presidential-actions/2025/01/temporary-withdrawal-of-all-areas-on-the-outer-continental-shelf-from-offshore-wind-leasing-and-review-of-the-federal-governments-leasing-and-permitting-practices-for-wind-projects/.

99 https://www.transportation.gov/briefing-room/trumps-transportation-secretary-sean-p-duffy-terminates-and-withdraws-679-million.

100 https://carboncredits.com/element-resources-launches-1-85b-hydrogen-plant-in-lancaster/.

using only renewable hydrogen are RPS-eligible, effectively limiting permissible hydrogen to strictly renewable sources.[101]

The CPUC has also directed IOUs to develop pilot projects for safe hydrogen blending to advance hydrogen innovation statewide, as well as continued biomethane reporting. These are evaluating real-world standards for safe injection and utilization of renewable hydrogen in existing gas infrastructure. Southern California Gas Company has also been pursuing the Angeles Link project since 2022 and completed Phase One feasibility studies in mid-2024.[102] In December 2024, SCE requested CPUC approval to begin Phase Two. The multi-phase Angeles Link project aims to establish the largest green hydrogen energy infrastructure system in the country.[103] [104]

Market momentum is also reflected in the ARCHES (Alliance for Renewable Clean Hydrogen Energy Systems) Hydrogen Hub, which in 2024 received $1.2 billion in federal DOE funding as part of a $12.6 billion public-private initiative.[109] ARCHES is a public-private partnership organized to accelerate hydrogen projects on an industrial scale to develop large-scale hydrogen production and distribution corridors.[105] Projects under ARCHES will span hydrogen production, transportation, and use—targeting sectors like public transit, heavy-duty trucks, and port operations (Los Angeles, Long Beach, Oakland), with production sites mainly in the Central Valley. The initiative aims to cut around 2 million metric tons of CO_2 annually, create ~220,000 jobs, ensure that 40% of benefits reach disadvantaged communities, and deliver $2.95 billion/year in health and economic gains starting in 2030. ARCHES was notified in early October 2025 of the cancellation of its federal funding and has appealed the cancellation.[106]

State legislative and programmatic support remain robust. The CEC's Clean Hydrogen Program funds demonstration and scale-up projects, emphasizing water-derived hydrogen and other renewable sources. SB 1420 (Caballero, 2024) streamlines CEQA permitting for hydrogen production and storage, further supporting infrastructure buildout and environmental review streamlining.[107]

The One Big Beautiful Bill Act (OBBBA) (Public Law 119-21) and new tariffs have impacted renewable hydrogen incentives. Specifically, the OBBBA terminates the Section 45V clean hydrogen production tax credit for facilities that begin construction after December 31, 2027. The federal legislation has also significantly reduced renewable hydrogen incentives for the wind and solar projects necessary to power green hydrogen production. New tariffs enacted in 2025 on imports have also compounded the challenges for the renewable hydrogen industry. The new tariffs, including a 10 percent baseline rate with steeper rates for certain countries, significantly increase the cost of imported components and equipment needed for green hydrogen production. Also, tariffs on imported steel, aluminum, and solar components raise construction costs for wind and solar projects that power green hydrogen. Despite the market changes in 2024 and 2025, California's renewable hydrogen sector still remains a national leader, bolstered by

101 https://pv-magazine-usa.com/2025/06/03/largest-hydrogen-plant-in-north-america-slated-for-california/.

102 Application of Southern California Gas Company (U 904 G) for Authorization to Implement Revenue Requirement for Costs to Enable Commencement of Phase 2 Activities for Angeles Link (A.24-12-011).

103 https://www.allenmatkins.com/real-ideas/california-continues-to-promote-clean-energy-transition-despite-federal-backstepping-on-clean-energy-and-hydrogen-funding.html.

104 https://archesh2.org.

105 https://www.latimes.com/environment/story/2024-07-17/california-hydrogen-hub-project-approved.

106 https://archesh2.org/year-in-review/.

107 https://www.gov.ca.gov/2024/07/17/california-launches-world-leading-hydrogen-hub/.

pioneering infrastructure projects, strategic public investment, and targeted policy innovations to ensure the state's clean energy future.[108]

Transmission Development Supporting RPS Implementation

The CPUC works with other State agencies and organizations in the planning of transmission that is necessary to support the delivery of renewable energy to California homes and businesses. In 2023, the CPUC, CEC, and CAISO renewed the 2010 Memorandum of Understanding (MOU) related to transmission planning and development. The MOU provides a key roadmap to describe the cooperation and collaboration of the three organizations for the timely development of transmission resources needed to achieve the state's clean energy goals reliably and economically. The MOU establishes the linkages between the CEC's Integrated Energy Policy Report and SB 100 activities, the CPUC's Integrated Resource Planning process, and the CAISO's 20 Year transmission Outlook and annual transmission planning and approval process. Under the MOU, the CPUC transmits resource planning portfolios consistent with the CEC's long term load forecast to the CAISO for use in transmission planning (which also uses the CEC's load forecast). The CAISO reviews the expected resource portfolios and authorizes transmission to support the expected resource portfolios. The CPUC has a role in transmission permitting for certain transmission lines (especially new large ones) and the CEC has a role in the opt-in permitting for renewable resources.

As acknowledged in the MOU, the State of California's transmission planning landscape can take several years from the initial resource portfolio development, through the CAISO Transmission Planning Process the required environmental review for new generation, interconnection and transmission infrastructure. Under the CPUC's General Order 131-E, the CPUC is responsible for permitting certain 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, though. Of the transmission projects implemented or currently in progress by the IOUs, less than 6% required a CPUC permit. The State of California website on transmission permitting and development describes the role of each entity in detail.[109]

General Order 131-E

On January 30, 2025, the CPUC adopted General Order (GO) 131-E, with updates designed to make it easier and faster to approve and build electric transmission projects and related grid upgrades in California[110]. These important updates are part of a broader effort to meet the state's clean energy goals by improving how transmission infrastructure is planned, permitted, and built. The decision approves the following improvements to the CPUC's transmission planning process:

- Allows applicant-prepared draft versions of CEQA environmental documents.

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108 See https://www.cleanegroup.org/regional-hydrogen-hubs-move-forward-ignoring-pushback/.
109 See https://www.energy.ca.gov/programs-and-topics/topics/california-transmission-system.
110 See D. 25-01-055: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M556/K483/556483080.PDF.

- Requires pre-filing consultation with the CPUC six months prior to an application submission.
- Authorizes a pilot program to explore faster CEQA review timelines.
- Implements presumption of need for projects when CAISO has already determined a project is needed.
- Clarifies advice letter protests and key terms, as well as simplifies reporting requirements.

The pilot program is an important component of the GO 131-E decision, continuing the CPUC's effort to streamline the permitting process by allowing the CPUC staff to identify opportunities to accelerate CEQA review times and therefore permitting timelines. The objectives of the pilot program are as follows:

- Evaluate the CPUC's existing CEQA review process for electric transmission projects with the goal of identifying process improvements and other opportunities to accelerate permitting timelines.
- Define and track the project-specific factors that affect electric transmission permitting timelines, including the causes and durations of "schedule change events" that can contribute to delays.
- Track and report on the implementation of newly introduced GO 131-E processes, e.g., the new application process wherein utilities are authorized to file applicant-prepared administrative draft versions of CEQA documents in lieu of a proponent's environmental assessment (PEA).
- Report the results of the pilot program to the public in biennial reports filed to the R.23-05-018 proceeding docket beginning December 1, 2026, as well as in a public-facing dashboard on the CPUC website to be regularly updated by CPUC staff.

CPUC staff will continue to process permit applications in the order they are received and will not be prioritizing pilot projects over other projects. Potential benefits of the pilot program include greater transparency and a heightened focus on identifying process improvements specific to the selected projects and assessing potential application to future projects.

In addition, CPUC Energy Division staff developed a set of metrics to track and report for each pilot project as part of the pilot program. On August 21, 2025, CPUC Energy Division staff held a workshop to present a list of proposed metrics for the GO 131-E pilot program and to elicit input on those metrics from R.23-05-018 proceeding parties and members of the general public. On September 5, 2025, the comment period on the proposed metrics ended. These comments have been considered and addressed in the list of metrics included in a dashboard that the CPUC will post on its website. The dashboard and biennial reporting will provide opportunities for ongoing public disclosure and engagement in the pilot program.

Transmission Projects Supporting RPS Resources

The CPUC is the lead CEQA agency for the transmission projects listed within this section. Each of the transmission projects that this section focuses on supports RPS resources and is in the active permitting, construction, and/or post-construction phases.

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 May 2, 2018 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 in January 2021. On May 24, 2023, SCE filed a Petition for Modification (PFM) requesting that the cost cap be increased to $295 million.

As of May 2025, SCE construction was complete, and all six Series Capacitors were successfully energized on the Eldorado-Lugo-Mohave (ELM) Project. However, SCE does not plan to operate ELM at an increased capacity until alternating current (AC) mitigation is complete, as described in Minor Project Refinement (MPR) No. 8 pursuant to Mitigation Measure UT-1 (MM UT-1) described below:

- MM UT-1 required SCE to complete an AC Study on the effects of the ELM Project 500kV lines on other utilities and complete any necessary mitigation work prior to in-servicing the Series Capacitors. The AC Study identified a need for mitigation work to install cathodic protection measures to safeguard SoCalGas pipelines (Lines 235 and 3000) from potential AC interference caused by the ELM Project's Lugo-Mohave 500 kV transmission line.
- This work would mitigate AC voltage and current density levels to ensure pipeline safety and integrity. The required AC study and agreement between SCE and SoCalGas on the type and location of cathodic protection took longer than anticipated. MPR No. 8 ensured SCE was able to continue to operate the Lugo-Mohave transmission line while the AC mitigation was studied and is being implemented. As described in SCE's August 26, 2025, MPR clarification request, SCE would continue operating the ELM lines at pre-project ratings until the AC mitigation is completed.

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.

The proposed project includes the 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[111] 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).[112] On June 9, 2023, DCRT made a filing with the Federal Energy Regulatory Commission (FERC) in Docket ER23-2309 requesting recovery on a project totaling $553 million. The construction of the Project is complete, and CAISO indicated an in-service date of July 1, 2024.

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 (A.24-07-018). The CAISO 2021-2022 Transmission Plan identified the Project as a needed upgrade to the California electric grid. The 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 Collinsville 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 miles 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.

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

112 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.

- Modifying PG&E's existing Vaca Dixon and Tesla Substations, including line relays and microwave towers, to support the new Collinsville Substation interconnection.

The Collinsville Project would facilitate the delivery of load from existing and proposed renewable generation projects in the northern Greater Bay Area, including future 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 (A.24-06-017).[113] 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 energy generation in the region. This project is estimated to facilitate the delivery of at least 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 Manning Substation to 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 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 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 prepared an initial study and mitigated negative declaration (IS/MND) to evaluate the environmental impacts of the proposed project pursuant to the California Environmental Quality Act (CEQA). The draft IS/MND was circulated for public review in March 2025, and the administrative final IS/MND was released in June 2025. D.25-09-013 approved the CPCN application and adopted the final IS/MND.[114] Construction is anticipated to begin in early 2026. The expected in-service date is June 1, 2028.

PG&E Darden Clean Energy Interconnection Project

The Darden Clean Energy Project, proposed by IP Darden I LLC and Affiliates, consists of a new 1,150 MW solar photovoltaic (PV) facility, an up to 4,600 megawatt-hour battery energy storage system (BESS), a 34.5-500 kV grid step-up substation, a 15-mile 500 kV generation intertie (gen-tie) line, and a 500 kV utility switchyard (i.e., the new Harlan Switching Station, to be constructed by IP Darden I LLC and Affiliates and subsequently transferred to PG&E) located in unincorporated Fresno County. To interconnect the project

113 More information on projects that the CPUC is overseeing and the California Environmental Quality Act (CEQA) process can be found at: https://www.cpuc.ca.gov/ceqa.
114 See D.25-09-013: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M581/K594/581594350.PDF.

to PG&E's existing Los Banos-Midway #2 500 kV transmission line, PG&E will relocate and loop approximately 1,000 feet of the existing transmission line into and out of the switching station. PG&E's interconnection activities were reviewed by the California Energy Commission (CEC) pursuant to CEQA via the CEC's Opt-In Certification Program, and the CEC approved the Darden Clean Energy Project on June 13, 2025. PG&E subsequently submitted a Tier 2 advice letter to the CPUC on July 30, 2025 (PG&E Advice Letter 7656-E), providing a notice of construction of the PG&E interconnection work. The CPUC accepted the advice letter on August 20, 2025. PG&E's construction is scheduled to begin in February 2026 and is expected to be completed by April 2027.

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 RECs[115] 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[116] to confirm each retail seller's actual REC claims. The CEC utilizes reports from the WREGIS[117] 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.

In 2017, the CPUC evaluated RPS-eligible procurement and made final compliance determinations for the compliance period 2011–2013 and determined that six retail sellers were non-compliant with their RPS procurement obligations.[118]

115 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.

116 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.

117 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.

118 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.

In 2019, the CPUC made final compliance determinations for the 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).[119] The third non-compliant retail seller did not procure enough RECs to meet its requirements.

In 2023, the CPUC made final compliance determinations for the 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[120] 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 to be out of compliance with RPS contract and reporting requirements due to one or more contracts missing required RPS non-modifiable standard terms and conditions.[121]

The CPUC will determine retail sellers' compliance for Compliance Period 2021-2024 after the retail sellers submit their Final RPS Compliance Reports. Those reports will be submitted within 30 days of the CEC publishing its RPS Procurement Verification Claims Report for the compliance period.

Enforcement

Compliance Period 2011-2013

In December 2017, the CPUC issued compliance determination letters to the 20 retail sellers operating in the compliance period 2011–2013. Six entities failed to comply with either the long-term contracting requirement 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.[122] The total penalties collected for the 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 the compliance period 2014–2016. Three entities failed to comply with either the long-term contracting requirement 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, the collection of Agera Energy's compliance period 2014-2016 penalties was contingent on

119 See D.17-06-026 for more information on the RPS long-term contracting rules.
120 Refer to D.11-12-052 and D.16-12-040 for complete rules governing the classification of RPS procurement.
121 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.
122 See D.19-08-007.

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 its assessed RPS penalty of $3,704,675, and the CPUC adjudicated its waiver request, resulting in a revised penalty of $352,500. The total penalties collected for the 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.[123]

Compliance Period 2017-2020

In April 2023, the CPUC issued compliance determination letters to the 42 retail sellers serving load in the 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 the 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 totaled $1,500. As in the prior compliance period, these penalties and citations are deposited in the Electric Program Investment Charge Fund to reduce ratepayers' investment costs.

Compliance Period 2021-2024

As noted above, the CPUC has not yet made compliance determinations for Compliance Period 2021-2024. Once compliance is determined, enforcement actions will be taken, if necessary.

123 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

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).[124] The state requires the 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, demographics of staff, and 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 workforce development opportunities with respect to the recruitment, hiring, and professional development practices associated with the implementation of the RPS program.

Current IOU RPS Workforce

Table 24 and Figure 10 provide an overview of the number of full-time PG&E, SCE, and SDG&E employees who worked on RPS-related issues from 2016 – 2025. In total, the three IOUs reported a cumulative increase in total employees working on RPS issues from 381 to 444 in the past year.

Table 24: Total RPS Employees at Investor-Owned Utilities (2016-2025)										
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Totals	161	169	135	302	271	307	172	228	381	444

Table 24: Total RPS Employees at Investor-Owned Utilities (2016-2025)
Data Source: PG&E, SCE, SDG&E, September 2025

Figure 10 illustrates how the number of RPS employees for the three IOUs has changed over the past ten years.[125]

124 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.

125 This time series data is current as of September 2025 and includes employment data from August 2016 through August 2025.

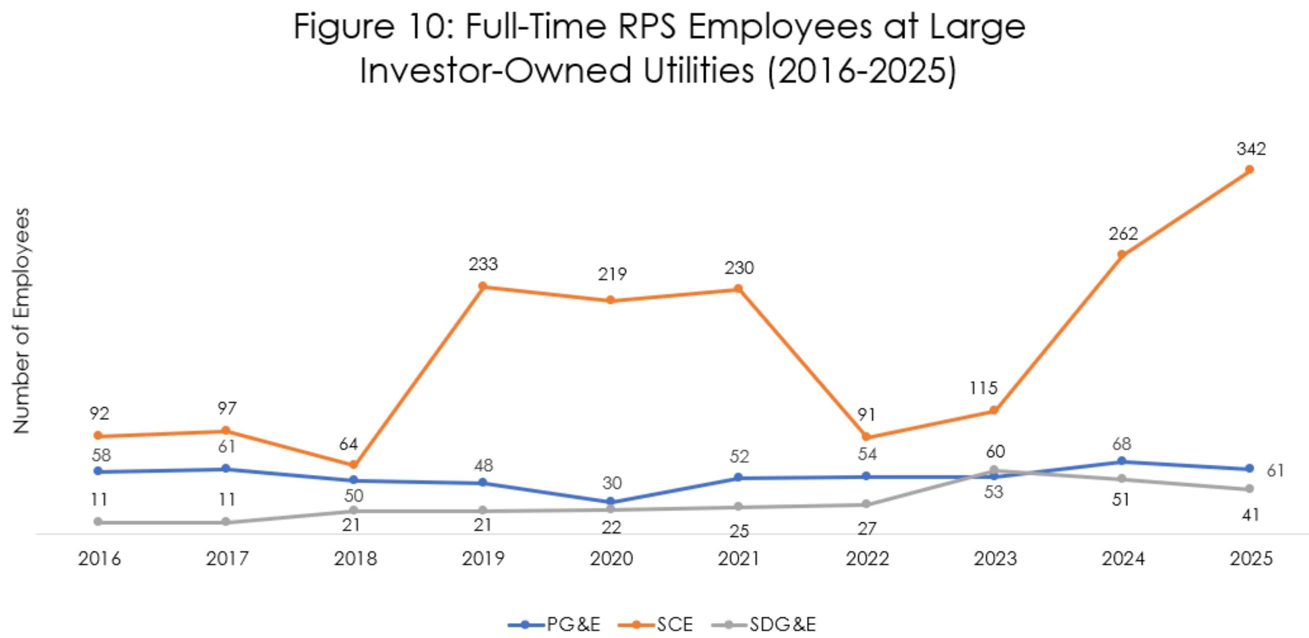

Figure 10: Full-Time RPS Employees at Investor-Owned Utilities (2016-2025)
Data Source: PG&E, SCE, SDG&E, August 2025

Current IOU RPS Workforce Composition

The IOUs reported having company-wide workforce development goals to build a workforce that reflects the composition of the State of California. In 2025, two of the IOUs reported working with organizations that focus on professional development for women, minorities, and disabled veterans. Common workforce efforts across the IOUs, which are further described below, 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. Figure 11 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.

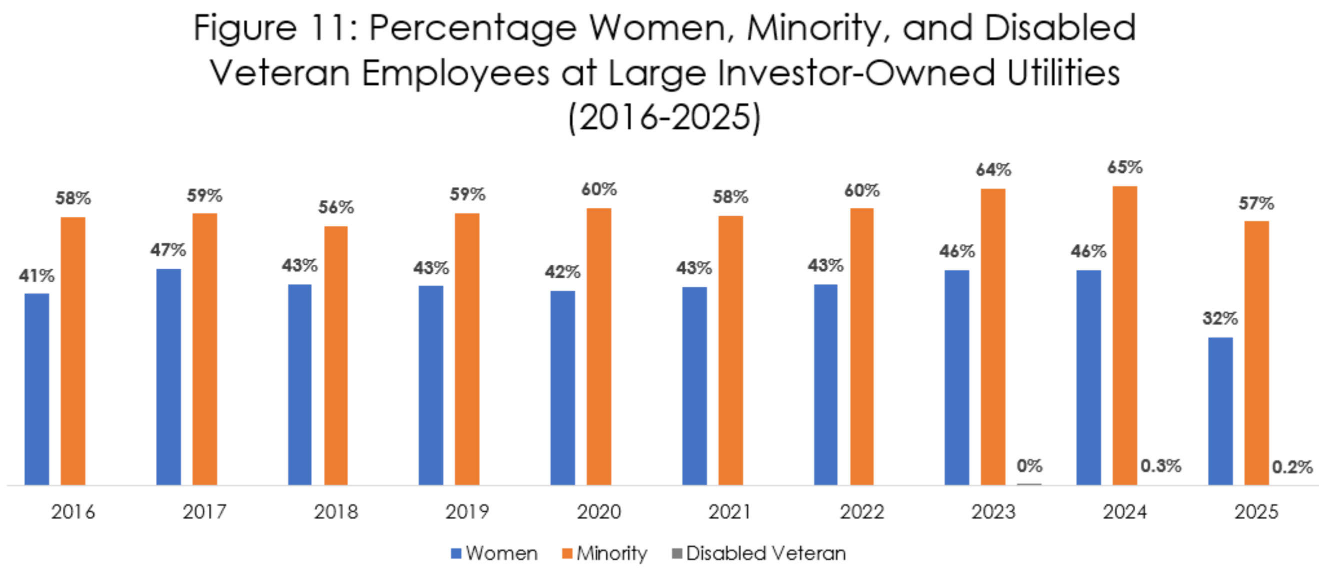

Figure 11: Percentage Women, Minority, and Disabled Veteran Employees at Investor-Owned Utilities (2016-2025)
Data Source: PG&E, SCE, SDG&E, August 2025

PG&E

Table 25 below shows the percentages of PG&E's RPS employees who are women, minorities, and disabled veterans compared with the total PG&E RPS staff. In 2025, PG&E's RPS staff comprised 39 percent women and 66 percent minority staff members. The percentage of women decreased while the percentage of minority staff increased over the past year. The percentage of women in PG&E's RPS workforce is 13 percentage points higher than the national average for women in the energy workforce.[126]

Table 25: PG&E's Percentage of Women, Minority, and Disabled Veteran RPS Employees[127] from 2016 to 2025										
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Women	22%	44%	43%	42%	35%	21%	35%	38%	43%	39%
Minority	48%	48%	47%	55%	60%	33%	52%	57%	63%	66%
Veterans	3%	0%	4%	n/a	n/a	n/a	n/a	n/a	0%	0%
Total RPS Staff	58	61	50	48	30	52	54	53	68	61

Table 25: PG&E's Percentage of Women, Minority, and Disabled Veteran RPS Employees from 2016 to 2025
Data Source: PG&E, September 2025

Data on the ethnic and racial backgrounds of PG&E RPS employees for 2021-2025 is displayed below in Table 26.

126 Data source: Department of Energy (DOE) Energy and Employment Report, 2025.
127 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.

Table 26: PG&E's Ethnic and Racial Background of RPS Employees from 2021–2025					
RPS Employees					Energy Workforce Average [128]
	2021	2022	2023	2024	2025	2024[129]
American Indian or Alaskan Native	0%	0%	0%	0%	2%	2%
Asian	35%	37%	39%	46%	39%	7%
Black/African American	0%	2%	2%	0%	2%	8%
Hispanic/Latino	12%	11%	13%	13%	18%	19%
Native Hawaiian or Pacific Islander	0%	0%	0%	0%	0%	1%
Two or more races	3%	2%	4%	3%	5%	5%
White	50%	48%	43%	37%	34%	74%
Other	0%	0%	0%	1%	0%	3%

Table 26: PG&E's Ethnic and Racial Background of RPS Employees from 2020–2024
Data Source: PG&E, September 2024, DOE Energy and Employment Report, 2025

SCE

Table 27 below 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.[130]

Table 27: SCE's Percentage of Women, Minority, and Disabled Veteran RPS Employees from 2021–2025					
	2021	2022	2023	2024	2025
Women	44%	46%	48%	46%	30%
Minority	60%	63%	68%	68%	58%
Veterans	No Data	No Data	<1%	0%	0%
Total RPS Staff	230	91[131]	115	262	342

Table 27: SCE's Percentage of Women, Minority, and Disabled Veteran RPS Employees from 2021–2025
Data Source: SCE, September 2025

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

128 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.

129 The DOE United States Energy & Employment reflects the calendar year of 2024 in its 2025 Annual Report.

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

131 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).

Table 28: SCE's Ethnic and Racial Background of RPS Employees from 2021–2025						
RPS Employees						Energy Workforce Average
	2021	2022	2023	2024	2025	2024
American Indian or Alaskan Native	0%	0%	0%	0%	1%	2%
Asian	33%	32%	36%	34%	30%	7%
Black/African American	6%	5%	6%	6%	2%	8%
Hispanic/Latino	17%	21%	20%	24%	20%	19%
Native Hawaiian or Pacific Islander	1%	0%	0%	0%	1%	1%
Two or more races	3%	4%	5%	5%	4%	5%
White	40%	37%	32%	32%	42%	74%
Other	0%	0%	0%	0%	0%	3%

Table 28: SCE's Ethnic and Racial Background of RPS Employees from 2021–2025
Data Source: SCE, September 2025

SDG&E

Table 29 below illustrates the number of SDG&E's RPS employees who are women, minorities, or disabled veterans. In 2025, SDG&E's RPS staff comprised 46 percent women and 34 percent minority staff members. The percentage of women in SDG&E's RPS workforce is 20 percentage points higher than the national average for women in the energy workforce.[132]

Table 29: SDG&E's Percentage of Women, Minority, and Disabled Veterans RPS Employees from 2021–2025					
	2021	2022	2023	2024	2025
Women	44%	41%	48%	51%	46%
Minority	48%	48%	53%	49%	34%
Veterans	0%	0%	0%	2%	2%
Total RPS Staff	**25**	**27**	**60**	**51**	**41**

Table 29: SDG&E's Percentage of Women, Minority, and Disabled Veterans RPS Employees
Data Source: SDG&E, September 2025

132 Data source: Department of Energy (DOE) Energy and Employment Report, 2025.

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

Table 30: SDG&E's Ethnic and Racial Background of RPS Employees from 2021–2025						
	RPS Employees (Full-Time)					Energy Workforce Average
	2021	2022	2023	2024[133]	2025	2024
American Indian or Alaskan Native	0%	0%	0%	0%	0%	2%
Asian	8%	11%	17%	18%	10%	7%
Black/African American	8%	7%	8%	6%	5%	8%
Hispanic/Latino	32%	32%	26%	15%	10%	19%
Native Hawaiian or Pacific Islander	0%	0%	0%	2%	0%	1%
Two or more races	5%	0%	4%	12%	10%	5%
White	45%	52%	52%	47%	61%	74%
Other	0%	0%	0%	0%	0%	3%

Table 30: SDG&E's Ethnic and Racial Background of RPS Employees from 2021–2025
Data Source: SDG&E, September 2025

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 for 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 Coworker Inclusion & Belonging (CI&B) and Talent Acquisition (TA) teams align with the Office of Federal Contract Compliance Programs (OFCCP) for affirmative action plans to ensure its workforce reflects the hometowns it serves. 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), and Center for Energy Workforce Development (CEWD).

Diverse Employee Recruitment

PG&E also 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,

133 The total count of SDG&E's ethnic and racial background of RPS employees excludes 2 staff who declined to state their race/ethnicity.

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, and 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, early career, and critical positions like data scientist, cybersecurity, continuous improvement, environmental policy, planning, skilled trades, engineering, and IT. SCE's career site is also fully mobile and accessible to individuals with disabilities, while providing information on pre-employment assistance and accommodation requests. Visitors on the site and other channels are invited to join the SCE Talent Network which 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. SCE uses SFX, a talent marketing platform that combines customer relations management (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 in and continue to partner with several professional and community groups.

Their participation includes attending their career-related events, being on-podium (keynote) at its annual conferences, and mentoring its 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 workforce development and inclusion throughout its 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.
- Attending onsite recruitment events at identified military bases (i.e., Camp Pendleton).
- Maintaining a military/veteran page on its 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.

- Establishment of a corporate SkillBridge program for registration with the Department of Defense, to prepare transitioning service members for civilian roles, that will ultimately provide them with relevant skills and experiences aligned with our company's workforce needs.

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, two of its Business Resource Groups, ABLE and Caregivers Connect, provide education to employees in discussions around important topics such as cancer recovery, low vision and blindness tools and resources, how to request and receive accommodations, and returning to work after a health challenge.

University & Campus Relations

SCE's college recruitment efforts are generally targeted at students pursuing degrees in engineering, accounting, finance, information technology, and cybersecurity at mostly California-based universities and colleges.

In addition, SCE partners with organizations such as Forte, 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 (HBCUs) 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 include 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 12 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, seven graduates from Cohort 2, nine graduates from Cohort 3, and four graduates from Cohort 4. Twelve scholars were selected for Cohort 5 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 for 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

SDG&E has stated that it does not recruit or train employees according to California Public Utilities Code 913.4(f). While SDG&E says that it sometimes engages in various workforce development activities, these efforts reflect broader company values and commitments to building a skilled and inclusive workforce.

SMJU Workforce Development

Table 31 below reports the number of full-time employees who worked on RPS-related issues at each of the three SMJUs (Bear Valley [BVES], Liberty, PacifiCorp) from 2021 to 2025.

Current SMJU RPS Workforce

Table 31: Total RPS Employees at SMJUs from 2021–2025					
	2021	**2022**	**2023**	**2024**	**2025**
BVES	3	3	3	3	2
Liberty	12	9	No Data	No Data	7
PacifiCorp	No Data	No Data	No Data	4	6

Table 31: Total RPS Employees at SMJUs from 2021–2025
Data Source: BVES, Liberty, and PacifiCorp, September 2025

Current SMJU RPS Workforce Composition

Within the limited RPS staff, PacifiCorp and Liberty reported that their staff is comprised of women and minorities, and none of the SMJUs 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 32: Bear Valley Electric Service's Ethnic and Racial Background of RPS Employees from 2021–2025						
	RPS Employees (Full-Time)					**Energy Industry Workforce Average**
	2021	**2022**	**2023**	**2024**	**2025**	**2024**
American Indian or Alaskan Native	0%	0%	0%	0%	0%	2%
Asian	33%	33%	0%	0%	0%	7%
Black/African American	0%	0%	0%	0%	0%	8%
Hispanic/Latino	0%	0%	0%	0%	0%	19%
Native Hawaiian or Pacific Islander	0%	0%	0%	0%	0%	1%
Two or more races	0%	0%	0%	0%	0%	5%
White	67%	67%	100%	100%	100%	74%
Other	0%	0%	0%	0%	0%	3%

Table 32: Bear Valley Electric Service's Ethnic and Racial Background of RPS Employees from 2021-2025
Data Source: BVES, September 2025

Liberty Utilities

The ethnic and racial backgrounds of Liberty Utilities' RPS employees are provided in the following table.

Table 33: Liberty Utilities' Ethnic and Racial Background of RPS Employees from 2021–2025						
	RPS Employees (Full-Time)					Energy Industry Workforce Average
	2021	**2022**	**2023**	**2024**	**2025**	**2024**
American Indian or Alaskan Native	2%	0%	No Data	No Data	0%	2%
Asian	7%	22%	No Data	No Data	43%	7%
Black/African American	8%	11%	No Data	No Data	0%	8%
Hispanic/Latino	19%	11%	No Data	No Data	0%	19%
Native Hawaiian or Pacific Islander	1%	0%	No Data	No Data	0%	1%
Two or more races	0%	0%	No Data	No Data	0%	5%
White	67%	56%	No Data	No Data	43%	74%
Other	0%	0%	No Data	No Data	14%	3%

Table 33: Liberty Utilities' Ethnic and Racial Background of RPS Employees from 2021–2025
Data Source: Liberty Utilities, September 2025

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 34: PacifiCorp's Ethnic and Racial Background of RPS Employees in 2024 and 2025			
	RPS Employees (Full-Time)		Energy Industry Workforce Average
	2024	2025	2024
American Indian or Alaskan Native	0%	0%	2%
Asian	25%	17%	7%
Black/African American	0%	0%	8%
Hispanic/Latino	0%	0%	19%
Native Hawaiian or Pacific Islander	0%	0%	1%
Two or more races	0%	0%	5%
White	75%	83%	74%
Other	0%	0%	3%

Table 34: PacifiCorp's Ethnic and Racial Background of RPS Employees in 2024 and 2025

Data Source: PacifiCorp, September 2025

Community Choice Aggregator (CCA) Workforce Development

Current CCA RPS Workforce

Table 35 below shows the total full-time RPS employees at each CCA in response to the CPUC's data request.[134]

134 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 35: Total Number of CCA RPS Employees from 2021 – 2025					
	2021	**2022**	**2023**	**2024**	**2025**
Apple Valley Choice Energy	0	2	0	8	8
Ava Community Energy	No Data	2	3	8	19
Central Coast Community Energy	No Data	5	8	No Data	3
City of Palmdale	No Data	No Data	1	4	3
City of Pomona	0	1	1	5	8
City of Santa Barbara	No Data	No Data	2	7	7
Clean Energy Alliance	No Data	1	1	1	3
Clean Power Alliance	7	8	No Data	10	13
CleanPowerSF	11	11	13	15	19
Desert Community Energy	No Data	3	4	4	5
King City Community Power	3	No Data	0	2	2
Lancaster Choice Energy	2	2	3	12	5
Marin Clean Energy	72	86	106	105	119
Orange County Power Authority	No Data	No Data	No Data	1	4
Peninsula Clean Energy	No Data	5	8	9	8
Pico Rivera Innovative Municipal Energy	0	2	0	8	6
Pioneer Community Energy	No Data	3	3	2	6
Rancho Mirage Energy Authority	1	1	1	7	6
Redwood Coast Energy Authority	8	10	5	33	36
San Diego Community Power	6	6	8	10	11
San Jacinto Power	0	0	0	3	3
San Jose Clean Energy	No Data	12	17	No Data	20
Silicon Valley Clean Energy	No Data	10	12	18	16
Sonoma Clean Power Authority	No Data	11	9	11	12
Valley Clean Energy Alliance	2	2	1	1	1

Table 35: Total Number of CCA RPS Employees from 2021 – 2025
Data Source: CCAs, September 2025

Current CCA RPS Workforce Composition

In 2025, 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 26 percentage points higher than the national average for women in the energy workforce.[135]

135 Data source: Department of Energy (DOE) Energy and Employment Report, 2025.

Table 36: Percentage of Women, Minority, and Disabled Veterans RPS Employees from 2021 – 2025 (Community Choice Aggregators)					
	2021	**2022**	**2023**	**2024**	**2025**[136]
Women	58%	54%	50%	56%	52%
Minority	33%	43%	36%	49%	44%
Disabled Veterans	No Data	0%	0%	0%	0%

Table 36: Percentage of Women, Minority, and Disabled Veterans RPS Employees from 2021 – 2025 (Community Choice Aggregators)
Data Source: CCAs, September 2025

The ethnic and racial backgrounds of the CCAs' RPS employees are shown in Table 37 below.

Table 37: Ethnic and Racial Background of CCA RPS Employees from 2023-2025				
	RPS Employees (Full-Time)			**Energy Workforce Average**
	2023	**2024**[137]	**2025**	**2024**
American Indian or Alaskan Native	1%	<1%	<2%	2%
Asian	15%	17%	17%	7%
Black/African American	7%	7%	8%	9%
Hispanic/Latino	13%	16%	16%	18%
Native Hawaiian or Pacific Islander	2%	2%	1%	1%
Two or more races	5%	6%	6%	5%
White	45%	51%	51%	74%
Other	12%	<1%	1%	2%

Table 37: Ethnic and Racial Background of CCA RPS Employees from 2023-2025
Data Source: CCAs, September 2025

The CPUC requested data from all CCAs. The CCAs generally report that they implement workforce development policies to build a workforce that promotes economic sustainability and inclusion in the renewable energy sector. Nine CCAs reported that they engaged in employee recruitment through diversity-focused job boards, and 14 CCAs reported employee recruitment activity through general job boards. Ten CCAs reported that they engaged in outreach and made partnerships with professional and community associations. Nine CCAs reported on relations with universities and campuses, and nine CCAs reported that they had made investments in employee training programs. Six CCAs noted partnerships with business resource groups.

136 The total count of women within the CCAs excludes 4 staff who declined to state their gender.
137 The total count of the CCAs' ethnic and racial background of RPS employees excludes 44 staff who declined to state their race/ethnicity.

ESP Workforce Development

Current ESP RPS Workforce

Table 38 shows the total full-time RPS employees at each ESP in response to the CPUC's data request.[138]

Table 38: Total Number of ESP RPS Employees from 2021 – 2025					
	2021	**2022**	**2023**	**2024**	**2025**
3 Phases Renewables	No Data	No Data	8	9	9
Calpine Energy Solutions	13	15	No Data	No Data	15
Constellation NewEnergy	No Data	26	40	43	43
Commercial Energy of Montana, Inc. (dba Commercial Energy of CA)	-	-	0	0	1
Calpine PowerAmerica	5	5	No Data	No Data	5
BP Energy Retail	No Data	No Data	No Data	No Data	0
Just Energy Solutions	No Data	5	4	7	8
Palmco Power [139]	No Data	No Data	0	No Data	No Data
NRG (formerly Direct Energy Business)	No Data	10	10	No Data	No Data
Pilot Power Group	3	3	2	2	2
Shell Energy North America	No Data	No Data	No Data	No Data	No Data
UC Regents	2	3	4	4	4

Table 38: Total Number of ESP RPS Employees from 2021 – 2025
Data Source: ESPs, September 2025

The CPUC requested data from all ESPs that were operational in 2025. 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 they had invested in employee training programs. One ESP noted that it had a partnership with at least one business resource group.

138 The ESPs have varying interpretations of the data request categories and, therefore, reported RPS employees may not be directly comparable.
139 Palmco Power is not currently serving load.

RPS Challenges and Policy Recommendations

Challenge 1: Market Conditions

Federal Policy Headwinds: New Federal Legislation and Executive Orders

In 2025, California's progress toward aggressive RPS targets is being challenged by federal policy shifts. The One Big Beautiful Bill Act[140] (OBBBA), signed July 4, 2025, imposes a rollback of federal renewable energy incentives, forcing a rapid recalibration of market expectations and project economics. The OBBBA accelerates the sunset of the federal Investment Tax Credit (ITC) and Production Tax Credit (PTC). Commercial projects (Solar and Wind) now must commence construction by July 4, 2026, if the project is not expected to be in service by December 2027 to qualify for the credits, sharply reducing eligibility and investor certainty.[141]

OBBBA also eliminates credit transferability established under the Inflation Reduction Act (IRA) of 2022[142], immediately limiting access to capital, particularly for small businesses, community-based ventures, and public agencies—key contributors to California's distributed procurement portfolio. Major federal Executive Orders issued in spring and summer 2025 that mandate strict domestic content and "foreign entity of concern" (FEOC) requirements further challenge the market and renewables project development. As a result, any solar, wind, or storage projects using key components from China or other flagged countries are now excluded from federal tax incentives, reshaping risk and financing for the majority of California installations.[143]

Recommendation

California's sustained leadership in clean energy will depend on a nimble regulatory approach to preserve RPS momentum and clean energy growth despite federal setbacks. Governor Gavin Newsom responded to the recent shifting landscape by signing an Executive Order that requires California agencies to fast-track permitting, grid interconnection, and review for "critical generation and storage projects" expected to come online in the next three years.[144] The CPUC has been directed to prioritize load forecasting, issue near-term procurement orders, and incorporate community solar more fully into planning.

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140 H.R. 1 - 119th Congress (2025-2026) (Public Law 119-21) https://www.congress.gov/bill/119th-congress/house-bill/1/text.

141 Politico (2025): https://www.politico.com/news/2025/08/06/california-solar-funding-trump-00496922.

142 H.R. 5376 117th Congress (2021-2022) (Public Law 117-169) https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

143 Holland & Knight (2025): https://www.hklaw.com/en/insights/publications/2025/04/executive-order-strengthens-the-reliability-and-security.

144 Executive Order N-33-25 https://www.gov.ca.gov/wp-content/uploads/2025/08/Clean-Energy-EO_8.29.25_FINAL.SIGNED.pdf.

The CPUC should take actions to enact Governor Newsom's executive order and work with other agencies to streamline multi-agency permitting and prioritize "safe harbor" status for projects initiated before OBBBA deadlines. Further, the CPUC should continue to strengthen grid and regional partnerships by continuing to work closely with CAISO, municipal utilities, and neighboring states to upgrade transmission, repower retiring facilities, and integrate distributed resources into load forecasts, focusing on market signals and reliability.

Finally, the CPUC will continue to monitor market and policy developments, reporting progress and advising further legislative and procurement action as needed to realize California's clean energy goals.

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 several years, an increasing number of interconnection requests to the California Independent System Operator (CAISO) presented a significant challenge for developers, transmission owners, and state authorities who deal with processing and permitting applications for generator and storage interconnections. On average, CAISO received 113 interconnection requests annually from 2010 to 2020.[145] That number grew to 373 requests in 2021 and then to 541 requests in 2023.[146] In order to address the backlog of projects awaiting review, CAISO paused acceptance of additional interconnection requests in 2024.

CAISO 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 estimated that the interconnection queue following the 2023 submitted requests contained more than three times the potential energy needed to achieve the objective of 100 percent clean energy by 2045 and far exceeded the available and planned grid transmission capacity to deliver this power to customers.[147]

The large number of interconnection project requests 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.

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

146 Data source: 188 FERC Order on Tariff Revisions, September 30, 2024: Document available at https://www.caiso.com/documents/sep-30-2024-ferc-order-accepting-tariff-amendment-interconnection-process-enhancements-2023-er24-2671.pdf.

147 Ibid.

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. The second reform involves scoring interconnection requests based on commercial interest, project viability, and system need. The top-ranked projects, located in zones where transmission capacity is available, advance to the CAISO interconnection study process, where they will 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.[148] CAISO submitted its IPE reforms to FERC in August 2024, and FERC approved the reforms without modification in September 2024.

CAISO reported in June 2025 that the interconnection reforms, as implemented in 2024 and 2025, significantly reduced the queue of projects to a more manageable number that is scaled to the volume of resources needed over the next 15 years. Specifically, the number of projects that advanced to CAISO's study process following the scoring and ranking evaluation is 145, as compared to the 541 projects initially submitted in 2023 that were subsequently reduced to 255 projects deemed complete and that met the initial requirements of the reforms.[149] The CPUC is continuing to actively participate in the CAISO IPE Initiatives to ensure alignment between the RPS and IRP procurement activities with the CAISO interconnection tariffs.

As a part of the 2024 FERC interconnection related proceeding, CAISO committed to monitoring key elements of the reformed interconnection process and to consider modifications in light of any lessons learned. At this time, CAISO is not recommending changes to the scoring process and continues the IPE process in late 2025 to consider stakeholder comments related to the interconnection request intake process.

Recommendation

The CPUC, as a stakeholder, should continue to work with CAISO under the 2023 MOU as well as to provide stakeholder initiative input and feedback to the CAISO as the interconnection reforms are considered and put into practice for future project submission periods. Additionally, the CPUC as requested in the Governor's August 2025 Executive Order, should coordinate with CAISO and the utilities to identify priority actions that can expedite transmission development to support near-term interconnection of new resources.[150] 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), of which the CPUC is a part, 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.

148 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.

149 CAISO Summary of Cluster 15 Intake Scoring Results, June 12, 2025: https://www.caiso.com/documents/summary-of-cluster-15-intake-scoring-results.pdf.

150 Executive Order N-33-25 https://www.gov.ca.gov/wp-content/uploads/2025/08/Clean-Energy-EO_8.29.25_FINAL.SIGNED.pdf.

Given the time expected for the top-ranked projects to advance through the CAISO study process and for future projects to be added to the queue, 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 the 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 of 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.

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

Assessment Summary

Since 2020, over 28 GW of new clean energy and storage resources have interconnected to the CAISO grid. Despite this dramatic growth in renewable energy deployment, California's electricity demand continues to rise, and more renewable resources are needed to meet this demand and meet the state's greenhouse gas reduction goals. In 2025, Executive Order N-33-25 ordered the CPUC to identify critical generation and storage resources in-development and coordinate with CAISO and utilities to expedite transmission development that supports the connection of these new resources.[151]

California Senate Bill 1174 (Hertzberg, 2022) supports this executive order by requiring electrical corporations that are participating transmission owners (PTOs) to submit annual data on transmission project delays and their impact on RPS-eligible renewable generation and storage resources. This submitted data was used to create the 2025 transmission system assessment below. This assessment is a tool used to understand the magnitudes and reasons for transmission project delays, and the impact of these delays on in-development renewable energy and storage resources seeking to interconnect.

2025 Transmission system assessment findings:

- The majority of PG&E and SCE in-development transmission projects have been delayed past their original in-service dates at 63 percent and 70 percent, respectively, with 64 percent of reported in-development transmission projects being delayed overall.
- There were a total of 449 delayed transmission projects reported with dependent renewable generation or storage resources.
- There is 21.8 GW of capacity of RPS eligible renewable generation and storage resources currently in development that depend on transmission projects that have already experienced a delay in in-service.
- For PG&E and SCE, 2.98 GW (35 percent) and 10.26 GW (77 percent) respectively of reported in development RPS eligible renewable generation and storage resources are delayed or are at risk of delay (totaling 13.24 GW or 35 percent).
- For PG&E transmission project delays due to "bundling dependencies" (a chain reaction of delays of dependent transmission projects) are expected to delay 2.5 GW of dependent in-development resources, while transmission project delays due to "financing" are expected delay or put at risk 2.85 GW, while "project design" delays or puts at risk 2.4 GW.

151 See Executive Order N-33-25: https://www.gov.ca.gov/wp-content/uploads/2025/08/Clean-Energy-EO_8.29.25_Formatted.FINAL_ATTESTED.pdf.

- For SCE, 6.5 GW of resources are expected to be delayed or are at risk of delay due to "material" delays related to the procurement of long lead time equipment necessary for transmission projects and network upgrades (e.g., circuit breakers, transformers, and specialized steel structures). For SCE bundling dependencies have the second largest impact, delaying or putting at risk nearly 4.4 GW of in-development resources.

Background

SB 1174 (Hertzberg, Chapter 229, Statues of 2022)[152] requires electrical corporations that own transmission facilities to 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. To comply with this statute, the CPUC requested that PG&E, SCE, and SDG&E report data on all transmission and interconnection projects and generation resources currently in development, as well as any transmission and interconnection projects that were completed January 1, 2020, to March 31, 2025, and experienced a delay in in-service from the original ISD.

SB 1174 also requires that the CPUC provide a systemwide assessment of delays to eligible renewable energy resources and energy storage resources based on the annual information provided by transmission owners. As electrical corporations and participating transmission owners (PTOs), PG&E, SCE, and SDG&E reported data related to SB 1174 within their 2025 Draft RPS Procurement Plans.[153] Only PG&E and SCE's data were considered for the systemwide assessment, and SDG&E was excluded for the reasons described below.

SDG&E's SB 1174 Data Deficiencies

In 2024, SDG&E reported no delayed transmission projects within its SB 1174 data. However, CPUC staff found this data to be incomplete and inaccurate due to staff being able to identify delayed transmission projects through SDG&E via other sources, such as CAISO's Transmission Development Forum (TDF) and CPUC's Transmission Project Review (TPR) process. However, due to time constraints, CPUC staff were unable to consider any updated SB 1174 data from SDG&E in the 2024 assessment.

For 2025, SDG&E again reported no delayed transmission projects within its SB 1174 data. CPUC staff reviewed SDG&E's data and again determined it to be incomplete and inaccurate due to identifiable delayed SDG&E transmission projects via the TDF. CPUC staff requested updated corrections to SB 1174 data from SDG&E which SDG&E provided. However, CPUC staff determined that the updated data was still not sufficient and, therefore, would be excluded from this assessment for a second year. CPUC staff made this determination based on the following primary reasons:

152 https://legiscan.com/CA/text/SB1174/id/2605746.

153 Non-electrical corporations (non-IOUs) that are participating transmission owners did not participate in the SB 1174 data collection process in 2025.

1. **Data was not provided for all in-development transmission projects**

   CPUC staff requested that PTOs include data for all in-development transmission projects. However, SDG&E responded to the update request that it "included in its 2025 SB 1174 Data Reporting Template transmission projects that it believes are relevant to renewable energy or energy storage resources with executed interconnection agreements required by the RPS Procurement Plans." CPUC staff have concluded that SDG&E only reported transmission projects that are relevant to renewable energy or energy storage resource interconnections, as opposed to all in-development transmission projects as required within the April 17, 2025, Assigned Commissioner and Assigned Administrative Law Judge's Ruling Identifying Issues and Schedule of Review for 2025 Renewables Portfolio Standard Procurement Plans (ruling).

2. **Incorrect "original in-service dates" were provided**

   A comparison of SDG&E's 2024 and 2025 SB 1174 data shows that SDG&E modified the requested "original" ISD for multiple transmission projects. CPUC staff defined within the SB 1174 data reporting template that the original ISD is "the expected in-service start date when the project was first approved". Additionally, CPUC staff identified within the template the sources that should be used to determine the original ISD, prioritized as:
   a. CAISO transmission plans
   b. TPR Data (Resolution E-5252 Attachment B)
   c. TDF "In-service Date at Approval in Transmission Plan"
   d. Internal utility project approval dates, including the first approved business case.

   As such, the original ISD should not fluctuate from year to year as defined in the template. However, SDG&E reported that original ISDs were based on "mutually agreed" dates. SDG&E communicated that "the 'Original In-Service Dates' of SDG&E's interconnection facilities are driven by customers' schedules mutually agreed upon by the CAISO, SDG&E, and the customer. As the customer modifies their schedule, the mutually agreed-upon date becomes the original in-service date and supersedes prior dates." CPUC staff disagree with this statement in the context of this data request, and as such, determine SDG&E's data to be unreliable.

3. **Data was not provided for all in-development generation projects**

   SDG&E communicated that "SDG&E has listed in the 'Generation Reporting' tab the renewable generation resources located within or outside its service territory with executed interconnection agreements that it is procuring for RPS compliance." However, SDG&E was to report all generation resources currently in development, regardless of whether SDG&E is procuring from the resource or not. CPUC staff have determined that SDG&E has provided incomplete reporting on its in-development generation resources.

SDG&E staff have acknowledged misunderstanding the scope of transmission projects and resources that must be included in the SB 1174 data request, and are cooperating with CPUC staff to correct and resubmit data, and come to an acceptable definition of "original" in-service dates which will be used in future SB

1174 assessments as a baseline to determine if SDG&E transmission projects are delayed. CPUC staff will continue to work to improve the quality and consistency of instructions for completing the SB 1174 data template and narrative statements.

Changes to the 2025 Assessment

CPUC staff made numerous changes to the 2025 SB 1174 data request and narrative template, based on lessons learned from the 2024 assessment and feedback from PTOs. The most significant changes to the data request and template include:

- New fields on permitting data. These fields were taken directly from the CPUC's Transmission Project Review (TPR)[154] process data template, which is used to identify the current (CPUC and CEQA) permitting status of transmission projects and help distinguish CPUC and CEQA-related permitting delays from permitting delays associated with other federal, state, and local agencies (e.g., National Environmental Policy Act (NEPA) permitting).
- A "Delay Resolver" field was added. This field identifies the entity (Utility, Customer, Developer, CAISO, CPUC, or federal/state/local agency) that can resolve the current in-service date delay. The purpose of this new field is to help identify the entities involved in transmission project delays.
- A "Secondary/Other Reasons for Delay" field was added. This field is used to more closely examine transmission projects delayed for multiple reasons or over a long period of time.
- Changes to the data template instructions to clarify the scope of transmission projects to be reported. Projects required to be reported include:
    - CAISO-approved or utility self-approved transmission projects, interconnection projects, and network upgrades needed for generator interconnection.
    - Both delayed and not delayed projects.
    - In-development transmission projects and projects that have become operational between January 1, 2020, and March 31, 2025.

Despite the clarifications listed above, PTOs had varying levels of difficulty complying with these instructions. CPUC staff will continue to work directly with the PTOs to improve the SB 1174 data template and narrative instructions to improve data accuracy and compliance.

For the 2025 assessment, a significant change is the calculation of median delay times for each delay reason and delay resolver. In the 2024 SB 1174 assessment, only already in-service transmission projects (status = operational) were used to calculate median delay times for each delay reason, but a lack of data on completed projects made median delay time calculations less statistically significant. In the 2025 assessment, staff included in-development transmission projects in the median delay time calculation.

154 Read more about the TPR here: https://www.cpuc.ca.gov/-/media/cpuc-website/industries-and-topics/documents/energy/electric-energy/electric-costs/resolution-e-5252-atch-b-tpr-process-data-template.pdf.

Part 1: Transmission Project Delays

The PTOs were required to report all transmission and system network upgrades that are CAISO-approved or utility self-approved and needed for generator interconnections and that are currently in development and/or were completed between January 1, 2020, and March 31, 2025, and experienced a delay in in-service date from the original ISD. "Transmission projects" include transmission and interconnection projects, as well as network upgrades, that are CAISO-approved or utility self-approved and needed for generator interconnections. A transmission project is defined as "in development" if the project has commenced but is not yet in service or operational. A transmission project is defined as "delayed" when its current or actual ISD is later than the project's original ISD.

Table 39 below illustrates that the PTOs reported delays of ISDs for 328 out of 513 (64 percent) in-development transmission projects reported. In the context of this assessment, a transmission project is considered delayed when the current expected or actual ISD is later than the original ISD.

Table 39: Reported Transmission Projects by PTO			
	PG&E	**SCE**	**Totals**
In-Development Transmission Projects			
Total	440	73	513
Delayed	277	51	328
Percent	63%	70%	64%
Operational Transmission Projects (2020 to 3/31/2025)			
Total	207	27	234
Delayed	93	25	118
Percent	45%	93%	50%
All Transmission Projects			
Total	647	100	747
Delayed	370	76	446
Percent	57%	76%	60%

Table 39: Reported Transmission Projects by PTO
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

For both PG&E and SCE, the majority of reported in-development transmission projects have been delayed past their original planned ISDs (63 percent and 70 percent, respectively), indicating that transmission project delays are widespread across California's electric grid.[155]

155 PG&E and SCE serve the majority of California geographically and its customers, approximately 16 million and 15 million respectively: https://www.pge.com/en/about/company-information/company-profile.html, https://www.edisoncareers.com/about-sce/.

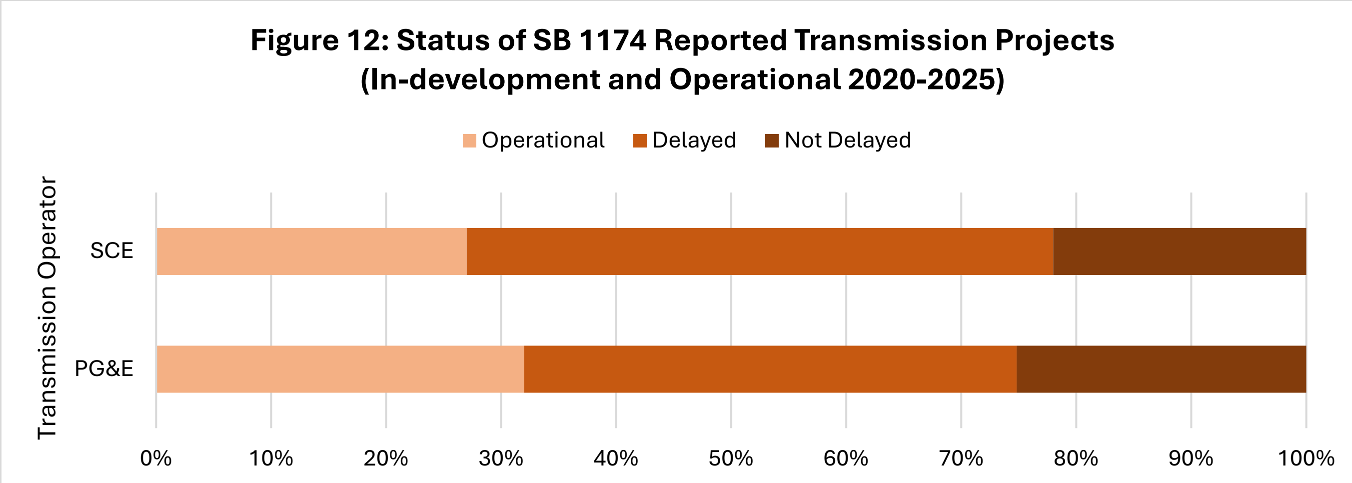


Figure 12: Status of SB 1174 Reported Transmission Projects (In-development and Operational 2020-2025)
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

Reasons for Delays

The PTOs were required to attribute a primary reason for delay for any transmission project that has a planned or actual ISD that is later than the original ISD. CPUC staff provided the PTOs with 14 choices in attributing a primary delay reason to a delayed transmission project:

1) Bundling Dependencies
2) Clearances
3) Financing
4) ISO Action
5) Land Rights
6) Material
7) Outage
8) Permitting (CPUC/CEQA)
9) Permitting (non-CPUC/CEQA)
10) Project Design
11) Supply Chain Delays
12) Vendor Quality/Delays
13) Weather
14) Workforce Availability

A PTO could also mark a transmission project as "Completed Early" if the project had an actual ISD that was ahead of the original ISD. Additionally, for some transmission projects, it is possible that the PTO did not have insight into the reason for a delay on the customer's side. Those delayed projects have been labeled as "no data" for the delay reason. See Table 40 below for a breakdown of all delayed transmission projects by delay reason.

Table 40: Transmission Project Delay Reasons by PTO			
Delay Reason	**PGE**	**SCE**	**TOTALS**
Bundling Dependencies	101	16	117
Clearances	7	--	7
Financing	48	--	48
Land Rights	23	1	24
Material	14	14	28
No Data	--	24	24
Outage	--	1	1
Permitting (CPUC/CEQA)	42	3	45
Permitting (non-CPUC/CEQA)	29	2	31
Project Design	87	11	98
Supply Chain Delays	19	--	19
Vendor Quality/Delays	--	3	3
Weather	--	1	1
TOTALS	**370**	**76**	**446**

Table 40: Transmission Project Delay Reasons by PTO
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

PG&E's Delay Reasons

Bundling Dependencies

The largest number of PG&E's delayed transmission projects (101) are primarily delayed due to bundling dependencies, in which work on one project cannot continue until work on other dependent transmission upgrades have been completed. This reason for delay could indicate a systematic problem of insufficient slack in project schedules to accommodate unforeseen changes. This excerpt from PG&E's SB 1174 narrative statement in its 2025 Draft RPS Procurement Plan describes potential causes and impacts of bundling dependencies:

> "Bundling Dependencies/Clearances: Scheduling clearance windows for testing is a key element that must be managed to allow projects to progress during periods when the electrical system is not stressed with high demand. Clearances are not commonly issued during the months of April through October, which constrains the time when projects may access the electrical grid. When multiple projects are on-going or planned at PG&E substations, PG&E must clear constraints and make way for safe operation of the site while work is being performed. These arrangements tend to increase scope and costs on projects and may also have a tendency to shift out clearances to ensure safe operations while work is completed"

Project Design

The second largest number of PG&E's delayed transmission projects (87) are delayed due to project design, which includes project re-designs and other design work beyond the original project scope. PG&E's SB 1174 narrative template describes underlying reasons for project design delays including:

- High demand for specialized engineering resources.
- Interconnection customer and utility side redesigns triggered by CEQA, Environmental Impact Assessment Reports (EIR), and other permitting processes.
- Project suspensions which delay PG&E design milestones.

SCE's Delay Reasons

Customer Action

The largest number of SCE's delayed transmission projects (24) had no reason for delay given (or no data was provided). Figure 14 below shows that the customer is the delay resolver for these no data projects. Staff observe that PTOs often do not have good visibility into the reasons that interconnection customers delay connecting new generation and loads to the grid. But better communication between PTOs and their customers is essential, given the volume of resources seeking interconnection and the financial and reliability risks associated with interconnection delays.

Other Key Delay Reasons

Excluding no data delayed projects, the largest numbers of SCE projects were delayed by bundling dependencies, material, and project design. Material delays are a significant driver of transmission project delays overall, and these delays are associated with procuring long-lead-time materials, such as circuit breakers, power transformers, and steel structures, necessary for transmission upgrades.

Delay Resolvers

Additionally, for any delayed transmission projects, PTOs were required to identify which party is responsible for resolving the current delay (the delay resolver). CPUC staff provided the following choices to PTOs to identify delay resolvers:

1) Utility
2) Customer
3) Developer
4) CAISO
5) CPUC
6) Agency - Federal
7) Agency - Local
8) Agency - State

Table 41 below details the identified delay resolvers for all delayed transmission projects reported by PTOs. PG&E reported that the delay resolver for all its delayed transmission projects is either the interconnection customer or PG&E itself, whereas SCE reported other delay resolvers including federal, state, and local agencies.

Table 41: Delay Resolver by PTO			
Delay Resolver	**PGE**	**SCE**	**TOTALS**
Agency - Federal	--	1	1
Agency - Local	--	1	1
CAISO	--	1	1
CPUC	--	3	3
Customer	180	15	195
No Data	--	10	10
Utility	190	45	235
TOTALS	**370**	**76**	**446**

Table 41: Delay Resolvers by PTO
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

In Figure 13 below, PG&E almost equally splits responsibility for resolving delays between itself and its customers. For transmission projects delayed by Permitting (CPUC/CEQA), PG&E generally finds itself to be the delay resolver, while for project design delays, PG&E generally finds interconnection customers to be the delay resolvers.

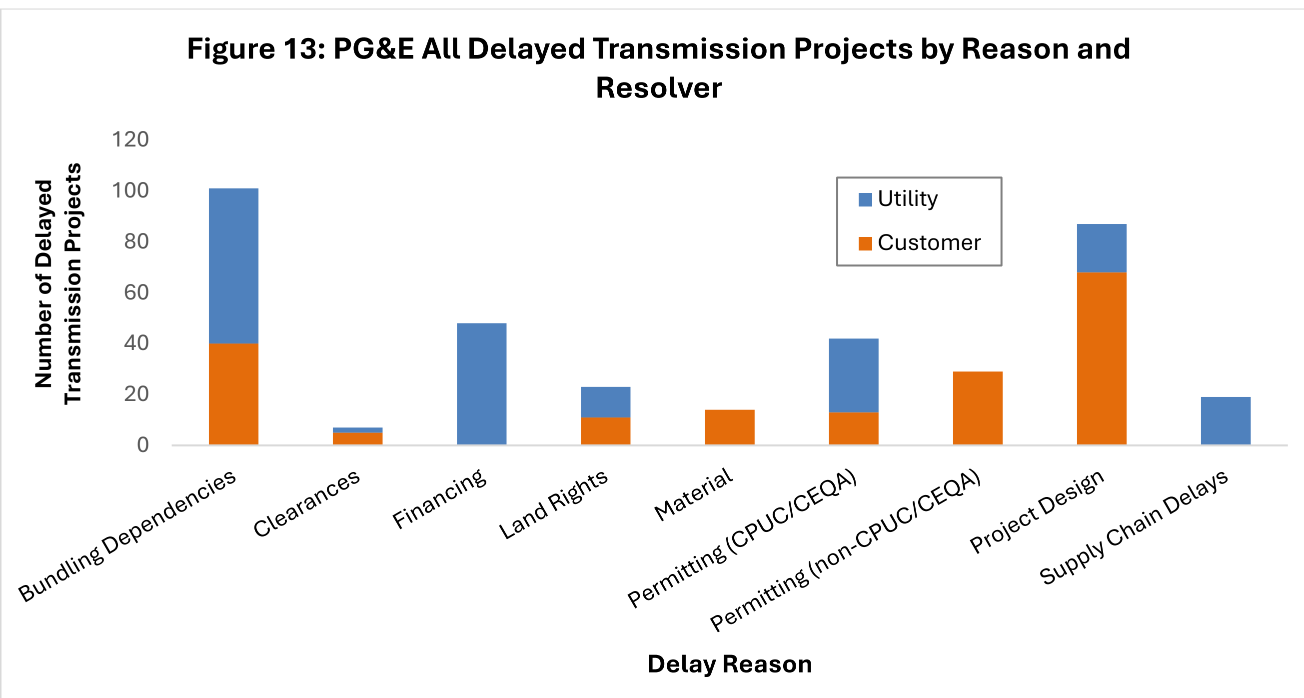


Figure 13: PG&E Delayed Transmission Projects by Reason and Resolver
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

Figure 14 below shows that for SCE a delay reason is almost always tied to a single delay resolver. For example, all project design transmission project delays are connected to the utility as being the delay resolver.

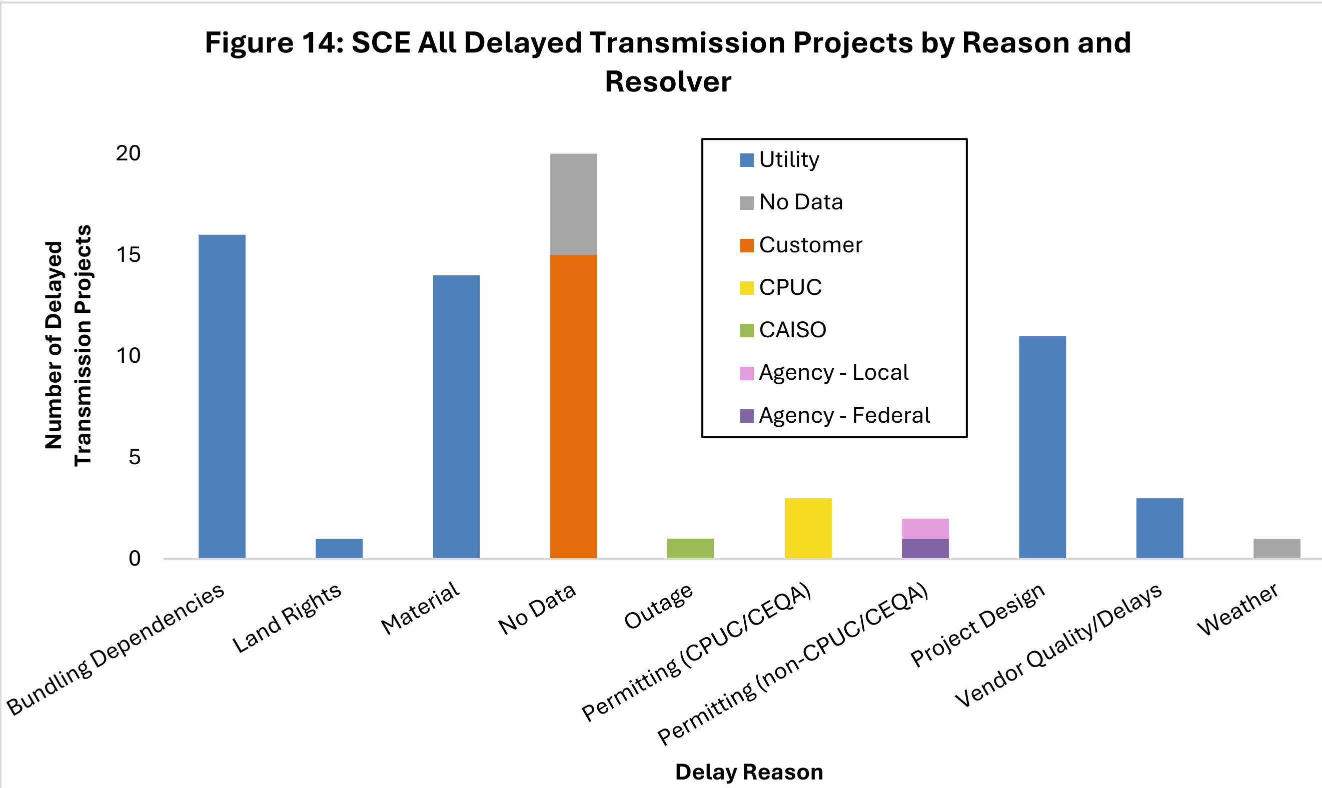


Figure 14: SCE Delayed Transmission Projects by Reason and Resolver
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

Median Delay Times for Delayed Transmission Projects

This assessment considers the length of delay, in months, for each delay reason and each delay resolver by calculating the median delay time.

In the 2024 SB 1174 assessment, only already in-service (operational) transmission projects were used to calculate median delay times for each delay reason. But a lack of data on completed projects made median delay time calculations less statistically significant. In the 2025 assessment, CPUC staff addressed this problem by calculating median delay times using data from all reported delayed transmission projects, including those currently in development and/or those completed January 1, 2020 to March 31, 2025.

Staff did not see evidence in the 2025 SB 1174 data that including in-development projects caused a significant underestimation of median delay times and found a potential decrease in accuracy to be an acceptable tradeoff for more statistical significance. This calculation change impacts the quantity of in-development resources categorized as "at risk" of being delayed, but it does not change the capacity (GW) of resources categorized as "delayed" by the delayed transmission upgrades that these resources depend on. The number of resources categorized as at risk or delayed are detailed in the following section.

Table 42: PG&E Median Delay Times by Reason, and Associated Delay Resolver(s), in Months		
Delay Reason	**Delay Median**	**Associated Resolver/s**
Bundling Dependencies	15.17	Utility, Customer
Clearances	1.43	Utility, Customer
Financing	27.33	Utility
Land Rights	31.77	Utility, Customer
Material	6.10	Customer
Permitting (CPUC/CEQA)	101.32	Utility, Customer
Permitting (non-CPUC/CEQA)	4.40	Customer
Project Design	4.63	Utility, Customer
Supply Chain Delays	3.43	Utility

Table 42: PG&E Median Delay Times by Reason and Resolver in Months
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

Table 42 above shows that median delay times are longer when PG&E is the delay resolver than when interconnection customers are the delay resolver. It also shows that PG&E transmission project delay times related to CPUC or CEQA permitting are significantly longer than other types of delays. However, CPUC staff note that the 121 month median delay time for Permitting (CPUC/CEQA) is attributed to only two transmission projects (broken down as sub-projects in PG&E's SB 1174 data) and may not represent a meaningful median delay time. These two projects are:

- Estrella Substation Project
  - Currently under construction but permitting took significantly longer than usual due to public controversy surrounding the need for the project and the evaluation of non-wire alternatives in the project's CEQA document.
- Wheeler Ridge Junction Substation (Casa Loma).
  - As of the date this report was written, CPUC staff have not yet seen a permitting application for Wheeler Ridge and expects an application from PG&E in quarter one 2026.

It is difficult to draw any conclusions about median delay times related to Permitting (CPUC/CEQA) with only two projects. Additionally, CPUC staff are unclear why PG&E attributed Wheeler Ridge Junction Substation's delay to Permitting (CPUC/CEQA) considering the CPUC has not received a permitting application for this project yet.

Table 43: SCE Median Delay Times by Reason, and Associated Delay Resolver(s), in Months		
Delay Reason	**Delay Median**	**Associated Delay Resolver(s)**
Bundling Dependencies	40.72	Utility
Land Rights	34.43	Utility
Material	23.70	Utility
No Data	19.33	Customer, No Data
Outage	17.30	CAISO
Permitting (CPUC/CEQA)	47.33	CPUC
Permitting (non-CPUC/CEQA)	79.22	Agency - Federal, Agency - Local
Project Design	30.20	Utility
Vendor Quality/Delays	7.83	Utility
Weather	54.23	No Data

Table 43: SCE Median Delay Times by Reason and Resolver in Months
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

Whereas PG&E only attributed delays to itself (utility) and its customers as resolvers, SCE reported delays attributed to a much larger list of resolving parties. Table 43 above illustrates that SCE transmission projects delayed due to permitting (non-CPUC/CEQA) and needing resolution from a federal agency has the longest median delay time at 110 months (9.17 years). This 110 month delay is caused by a single project: Lugo-Victorville RAS. In SCE's 2024 SB 1174 data the purpose of Lugo-Victorville RAS was described as "Install required facilities necessary to protect the jointly owned (SCE-LADWP) Lugo-Victorville 500 kV T/L following outage conditions within the SCE East of Pisgah (EOP) Area." CPUC staff understand, however, that although the Bureau of Land Management (BLM) is the lead agency for NEPA permitting on Lugo-Victorville RAS[156], the Lugo-Victorville 500 kV line is experiencing ongoing delays related to material procurement and outage scheduling[157], and these are likely the true drivers delaying the Remedial Action Scheme (RAS) work.

SCE's data also shows that there are several delay reason and resolver combinations that have a median delay time that is longer than 36 months (3 years), including Permitting (non-CPUC/CEQA)/Agency-Local, Permitting (CPUC/CEQA)/CPUC, and Bundling Dependencies/Utility. Of note, there is also a long median delay time for projects delayed by SCE's customers (40 months or 3.3 years), however no data was provided by SCE as to the cause for the delays on these projects. Also, projects delayed due to weather have a significant median delay time (54 months or 4.5 years), but SCE did not attribute any delay resolvers to these types of delayed transmission projects.

156 According to SCE's 2025 SB1174 data, BLM is the lead permitting agency for Lugo-Victorville RAS.
157 Reasons for Lugo-Victorville 500 kV line delays were discussed during the July 2025 Transmission Development Forum: https://www.caiso.com/documents/presentation-sce-transmission-development-forum-jul-30-2025.pdf.

Categorizing Resources As Delayed and At Risk of Delay

Parts 2 through 4 of this assessment consider the current and potential impacts of delayed in-development transmission projects on dependent generation and storage resources via median delay times. To assess this impact, staff developed a categorization rubric to assess delays. Reported generation and storage resources were assigned into one of three categories: Not Delayed, At Risk (for delay), and Delayed.

PTOs were required to submit data on all in-development (not yet in-service) renewable energy and storage resources with executed interconnection agreements that are expected to come online in their service territories.[158] And for each reported transmission project, PTOs were required to identify the subset of in-development resources that depend on the project. CPUC staff used information about the in-service dates of these transmission projects and dependent resources to categorize resources as "Delayed", "At Risk", or "Not Delayed". Delayed resources provide insight into already occurring impacts while At Risk resources provide additional insight into possible and probable impacts. Not Delayed resources provide additional context to the significance of Delayed and At Risk dependent generation and storage resources. These three categories are defined as:

1) Not Delayed:
    a. The generation or storage resource becoming operational does not depend on a transmission project; OR
    b. The generation or storage resource's ISD is scheduled after the current ISD of a transmission project(s) it depends on that is not currently delayed; OR
    c. The generation or storage resource's ISD is scheduled after the delayed transmission project's ISD it depends on AND the resource's ISD is later than the delayed project's ISD plus the median delay time for the project's delay reason.
2) At Risk:
    a. The generation or storage resource's current ISD is scheduled after the current ISD of the transmission project that it depends on; AND
    b. The delayed transmission project this resource depends on is associated with a median delay time which puts the potential ISD for the transmission project beyond the currently planned ISD for the resource.
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.

At Risk resources were categorized based on the median delay times for the delay reason of the transmission project they depend on. Figure 15 below illustrates an example of this categorization scheme.

158 The scope of resources requested includes all in-development resources with executed interconnection agreements, regardless of whether or not the IOU has contracted with the resource, and regardless of whether or not the resource is procured for RPS compliance.

Figure 15: Example Illustration of Not Delayed, At Risk, and Delayed Generation and Storage Resources

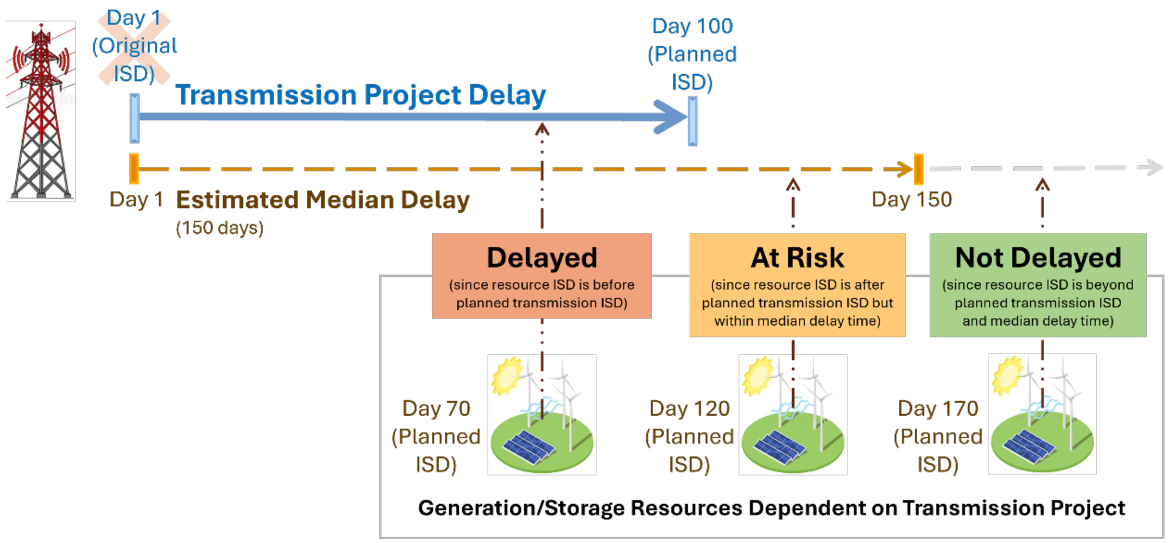


Figure 15: Example Illustration of Not Delayed, At Risk, and Delayed Generation Resources

It is worth noting that the assessment focuses solely on the impact of transmission project delays on eligible renewable energy resources and energy storage resources. 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.

In some cases, the PTOs were not able to provide details on the transmission projects that a generation or storage resource was dependent on, as the PTO 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.

Secondary and Other Reasons for Delay

The PTOs were asked to provide additional context for delayed transmission projects regarding secondary or other reasons for delay in addition to the primary reason for delay being identified. This field for secondary or other reasons for delay was added in the 2025 data request based on feedback from PTOs for the 2024 SB 1174 Assessment, where the PTOs expressed difficulty in attributing a project's delay to one primary reason and wished to provide additional context regarding delays. Additionally, the Assigned Commissioner ruling[159] requested that PTOs describe "any secondary reasons that have had a substantial impact on the project's delays" regarding discussing the top three transmission projects that have been delayed.

PG&E attributed 294 secondary/other delay reasons for delayed transmission projects to "Telecom". However, PG&E did not provide any detail as to what constituted a "Telecom" related delay. PG&E chose

159 See Assigned Commissioner ruling: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M563/K474/563474706.PDF.

not to provide any additional context on secondary or other reasons for delays within the narrative response of their 2025 Draft Annual RPS Plan.

SCE did notate secondary or other reasons for delay for most reported delayed transmission projects, identifying customer action as the most common secondary reason for delay. Within SCE's narrative response of their 2025 Draft Annual RPS Plan, SCE listed material as a secondary or other reason for delay for the Eldorado-Lugo-Mohave RPS Upgrade project.

PTO Support Efforts for Customers

The PTOs were asked to discuss how the PTO has improved support efforts to mitigate project delays when the customer is responsible for the delay.

PG&E identified that "PG&E supported customers with Pre-submission Permitting/ Environmental reviews, Customer Design Package Reviews, Utility and Telco Coordination Dependencies and issues, and clearance sequencing. Areas where PG&E's support was least impactful were in customer required county/city CUPs, building or construction permits and land-owner easements or agreements."

SCE reported that, "SCE has taken certain measures to assist customers in reducing some risks of delays. Such measures include maintaining an updated interconnection handbook (often helping customers understand requirements), proactively ordering common circuit breakers to minimize the impact of long lead times and working closely with customers to establish the most effective interconnection point."

Part 2: Impact of Transmission Project Delays on RPS Eligible Energy Resources

The previous part of the 2025 SB 1174 assessment summarized reported transmission projects and those that had experienced a delay from the original ISD, and introduced CPUC staff's approach to assessing impact on in-development resources. Parts 2 through 4 will detail how delayed transmission projects have impacted or could impact various types of generation resources, as the PTOs were required to report on currently in development renewable generation and storage resources. This part will focus specifically on how delayed transmission projects have impacted or could impact currently in development RPS eligible renewable generation resources.

Reported RPS Eligible Resources

PTOs were required to report every in development RPS eligible generation resource, as well as its associated capacity (MW) and expected annual generation (MWh). Table 44 below reflects RPS eligible resources by PTO.

Table 44: RPS Eligible Resources In Development by PTO			
PTO	**Total Resources**	**Total Capacity (GW)**	**Total Expected Annual Generation (GWh)**
PG&E	136	10.24	29,965
SCE	64	13.26	38,845
TOTALS	**200**	**23.50**	**68,810**

Table 44: RPS Eligible Resources in Development by PTO
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

RPS Eligible Resources Dependent on Delayed Transmission Projects

Table 45 below shows the RPS eligible renewable generation resources that are dependent on in development transmission projects that have also experienced a delay discussed in Part 1 (277 and 51 for PG&E and SCE respectively). A generation resource is considered dependent on a transmission project if the transmission project must become operational prior to the generation resource becoming operational.

Table 45: RPS Eligible Resources In Development Dependent on Delayed Transmission Projects			
PTO	**RPS Eligible**	**Total Capacity**	**Total Expected**
PG&E	30	5.60	16,382
SCE	27	9.57	29,166
TOTALS	**57**	**15.17**	**45,548**

Table 45: RPS Eligible Resources in Development Dependent on Delayed Transmission Projects
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

RPS Eligible Resources Delayed and At Risk of Delay

Part 1 discussed how median delay times for transmission project delay reasons were calculated and would be used to categorize dependent generation resources as Delayed, At Risk, or Not Delayed to illustrate existing and potential impacts of delayed transmission projects.

Figure 16 below shows the capacity (GW) of RPS eligible resources that are dependent on delayed or at risk transmission projects. Delayed projects total 7.25 GW, with 6.24 for SCE and 1.01 GW for PG&E. Total at risk projects are at 2.85 GW with SCE at 2.07 and PG&E at 0.78. For PG&E, 1.8 GW (32 percent) of RPS eligible resources dependent on delayed transmission projects are delayed or at risk of being delayed. For SCE, a much larger portion of RPS eligible resources dependent on delayed transmission projects have already been delayed or at risk of being delayed at 8.3 GW (87 percent). Between the two PTOs, there are 10.1 GW (67 percent) of RPS eligible resources dependent on delayed transmission projects that have already been delayed or at risk of being delayed.

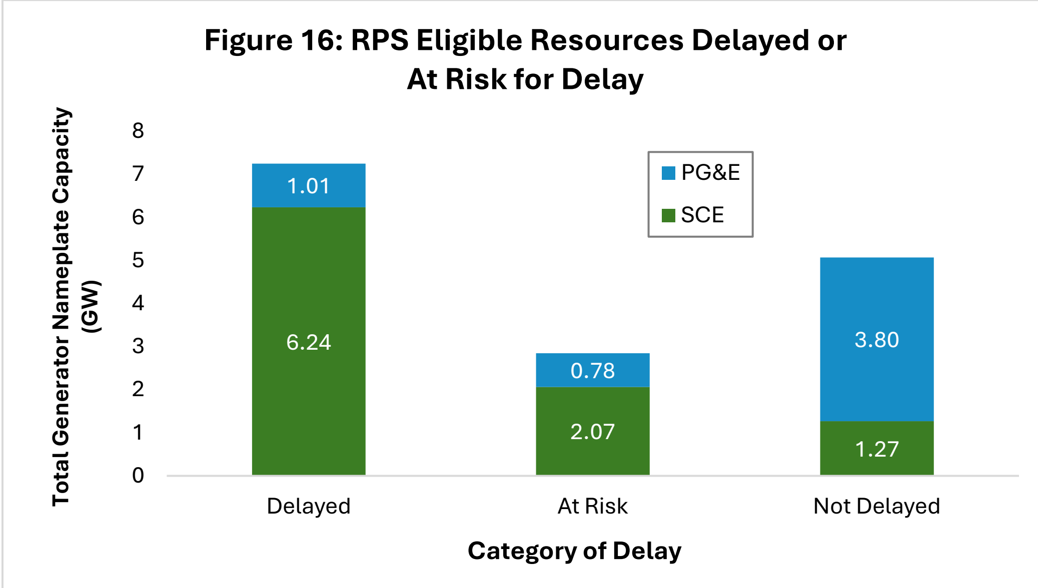


Figure 16: RPS Eligible Resources Delayed or At Risk for Delay
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

Part 3: Impact of Transmission Project Delays on Storage Resources

This part will focus on how delayed transmission projects have impacted or could impact currently in development storage resources reported by PTOs. SB 1174 specifically states that PTOs must submit data on storage resources impacted by delayed transmission projects.

Reported Storage Resources

PTOs were required to report every in-development storage resource, as well as its associated capacity (MW). Table 46 below breakdown storage resources by PTO.

Table 46: Storage Resources In-Development by PTO		
PTO	**Total**	**Total Capacity (GW)**
PG&E	44	5.99
SCE	45	10.99
TOTALS	**89**	**16.98**

Table 46: Storage Resources In-Development by PTO
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

Storage Resources Dependent on Delayed Transmission Projects

Table 47 below shows the storage resources that are dependent on in development transmission projects that have also experienced a delay. A storage resource is considered dependent on a transmission project if the transmission project must become operational prior to the storage resource becoming operational.

Table 47: Storage Resources In-Development Dependent on Delayed Transmission Projects by PTO		
PTO	**Storage Resources**	**Total Capacity (GW)**
PG&E	15	2.89
SCE	9	3.75
TOTALS	**24**	**6.64**

Table 47: Storage Resources In-Development Dependent on Delayed Transmission Projects by PTO
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

Storage Resources Delayed and At Risk of Delay

Figure 17 below shows the capacity (GW) of storage resources that are dependent on delayed transmission projects. For PG&E, 1.20 of 2.89 GW (42 percent) of storage resources dependent on delayed transmission projects have already been delayed or at risk of being delayed. Delayed projects total to 1.63 GW with SCE at 1.10 and PG&E at 0.53 GW. At risk projects total to 1.51 GW with SCE at 0.85 and PG&E at 0.66 GW. Referring to table 47, for SCE, 1.95 of 3.75 GW (52 percent) of storage resources dependent on delayed transmission projects have already been delayed or at risk of being delayed. Between the two PTOs, there are 3.15 of 6.64 GW (47 percent) of storage resources dependent on delayed transmission projects that have already been delayed or at risk of being delayed.

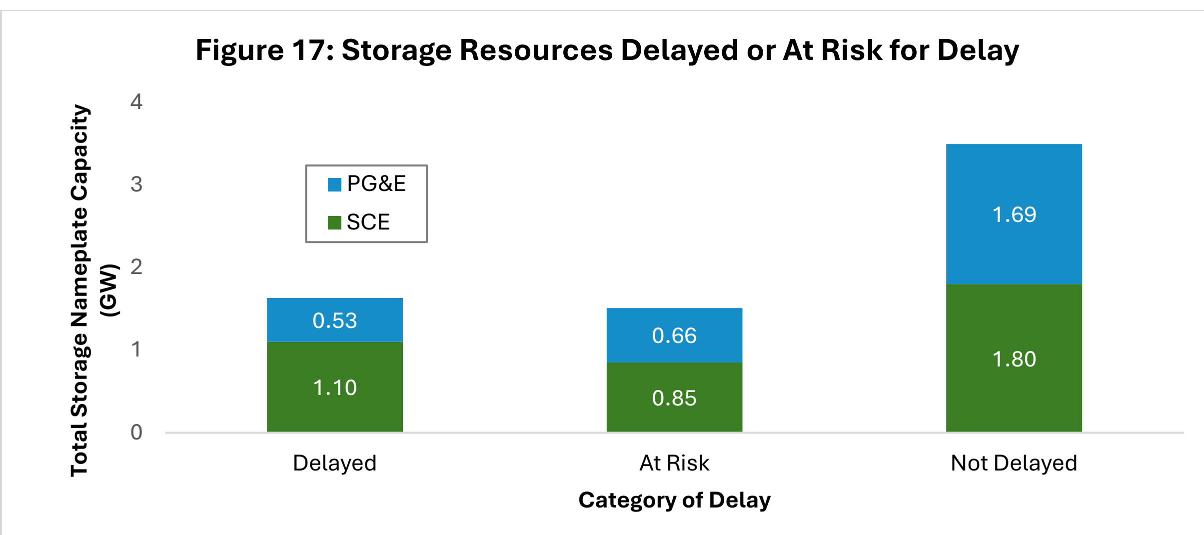


Figure 17: Storage Resouces Delated or At Risk for Delay
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

Part 4: Impact of Transmission Project Delays on All Reported Renewable and Storage Resources

The previous two parts discussed how delayed transmission projects have already or could potentially impact both RPS eligible renewable generation (renewable generation) and storage resources currently in development. This part assesses the overall impact of delayed transmission projects on all reported renewable generation and storage resources currently in development.

Reported Renewable Generation and Storage Resources

There were a total of 449 delayed transmission projects reported that have renewable generation or storage resources dependent on them. Table 48 below breaks down renewable generation and storage resources by PTO, as well as those resources that are dependent on currently in development transmission projects that have experienced a delay. Table 48 shows that 81 of 289 (28 percent) of reported renewable generation or storage resources are dependent on delayed transmission projects. However, those 81 in development resources represent 54 percent of the capacity (GW) of reported renewable generation or storage resources in development.

Table 48: Renewable Generation and Storage Resources by PTO

	All Resources Reported		Resources Reported Dependent on Delayed Transmission	
PTO	**Total**	**Capacity (GW)**	**Total**	**Capacity (GW)**
PG&E	180	16.23	45	8.48
SCE	109	24.25	36	13.32
TOTALS	**289**	**40.48**	**81**	**21.80**

Table 48: Renewable Generation and Storage Resource by PTO
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

Renewable Generation and Storage Resources Delayed and At Risk of Delay

Figures 18 and 19 illustrate that for PG&E, 2.98 GW of in development renewable generation and storage resources are already delayed or at risk for delay (35 percent). For SCE, 10.26 GW of in development renewable generation and storage resources are already delayed or at risk for delay (77 percent).

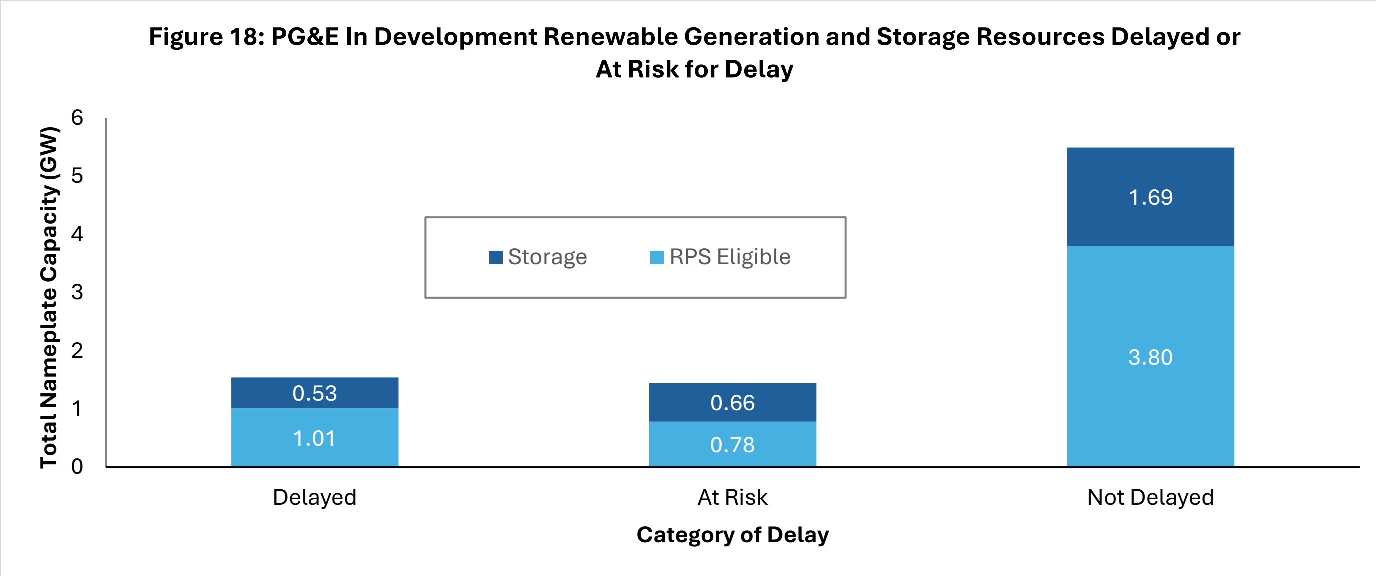


Figure 18: PG&E In Development Renewable Generation and Storage Resources Delayed or At Risk for Delay
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans

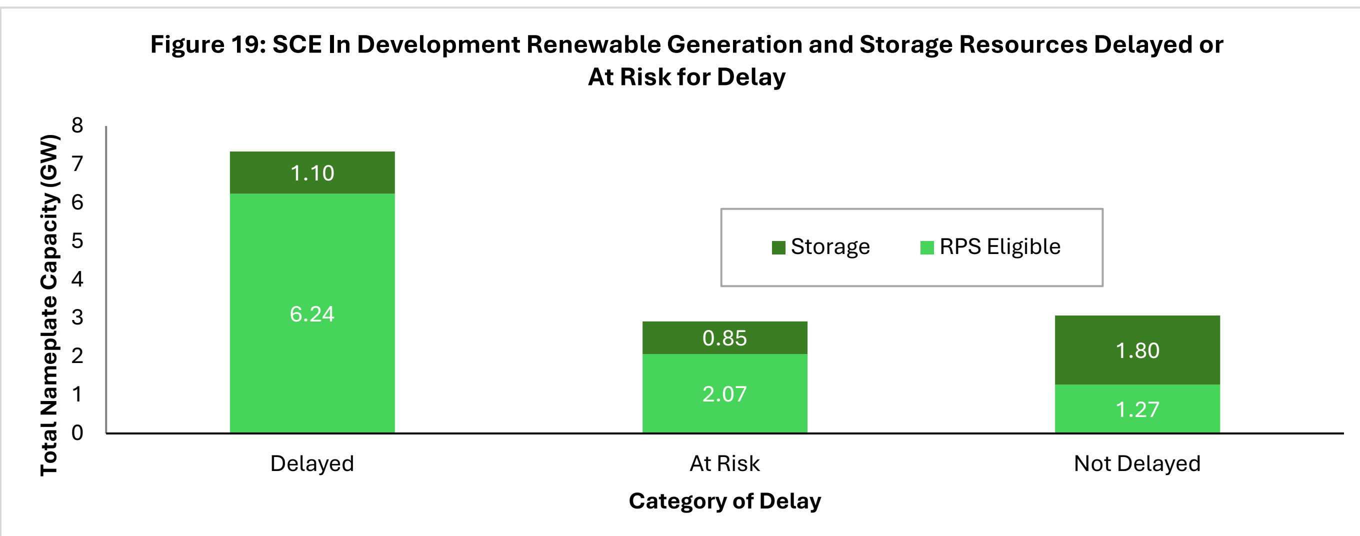


Figure 19: SCE In Development Renewable Generation and Storage Resources Delayed or At Risk for Delay
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans

Renewable Generation and Storage Resources Delayed and At Risk of Delay for Each Delay Reason

Figures 20 and 21 below further break down in development renewable generation and storage resources impacted by delayed transmission projects by looking at each transmission project delay reason and delay resolver combination. For PG&E, bundling dependencies, which PG&E fully attributed to its customers as the resolvers, are responsible for the largest number of delayed resources at 2.5 GW, and the second largest total delayed and at risk resources of any delay reason/resolver combination at 2.71 GW. Financing/utility has the most delayed and at risk for delayed resources of any delay reason and resolver combination at 2.85 GW, with project design/utility at third most overall with 2.4 GW. The prevalence of delays due to bundling dependencies may indicate overly rigid transmission project development timelines, which to some extent are shaped by seasonal outage windows.

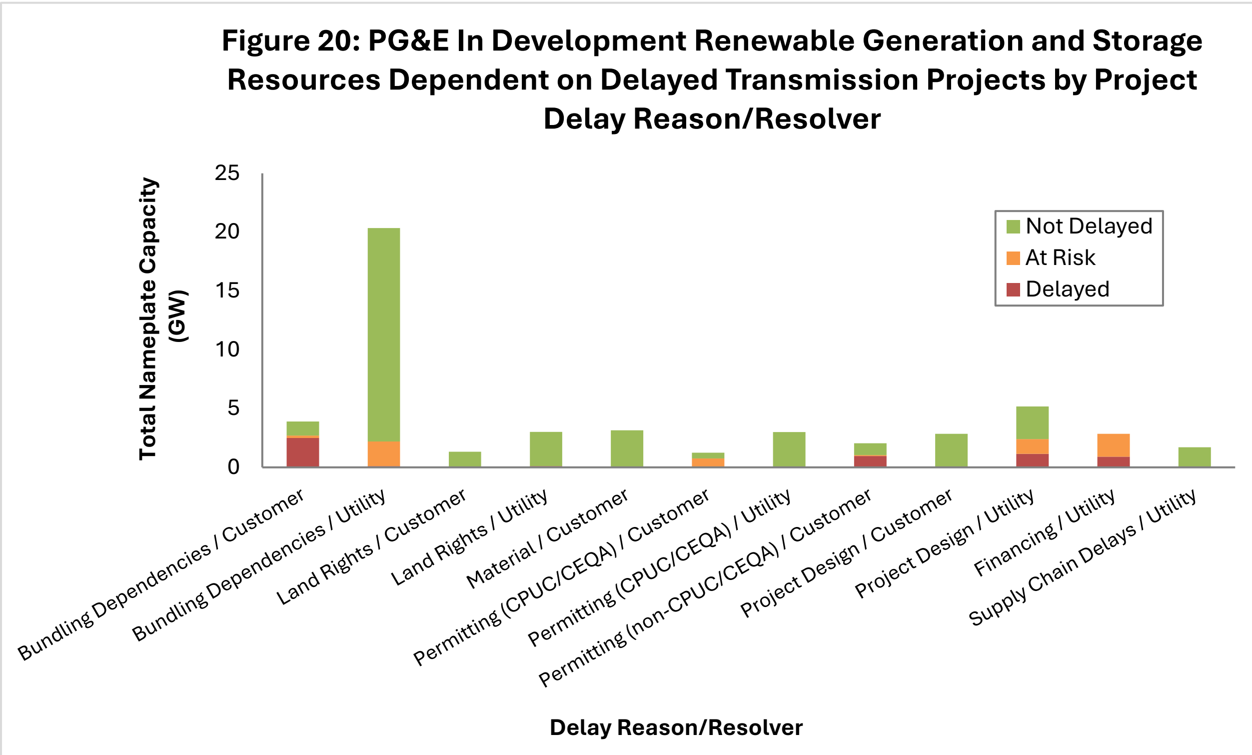


Figure 20: PG&E In Development Renewable Generation and Storage Resources Dependent on Delayed Transmission Projects by Project Delayed Reason/Resolver
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

For SCE, material/utility has the most delayed resources at 4.5 GW and the most delayed and at risk resources of any delay reason and resolver combination at 6.5 GW. Bundling dependencies/utility has the second most delayed and at risk of delayed resources at 4.39 GW, with no data/customer (1.89 GW) and no data/no data (1.8 GW) at third and fourth respectively. The importance of material delays related to the procurement of long lead-time resources, and bundling dependencies related to chain reactions of project delays are clear themes running through SCE's data and through this assessment in general. But it is difficult to draw conclusions from SCE's data in cases where no data was provided for delay reason. This missing data represents 3.7 GW of in development renewable generation and storage resources delayed or at risk of delay from delayed transmission projects, which is significant.

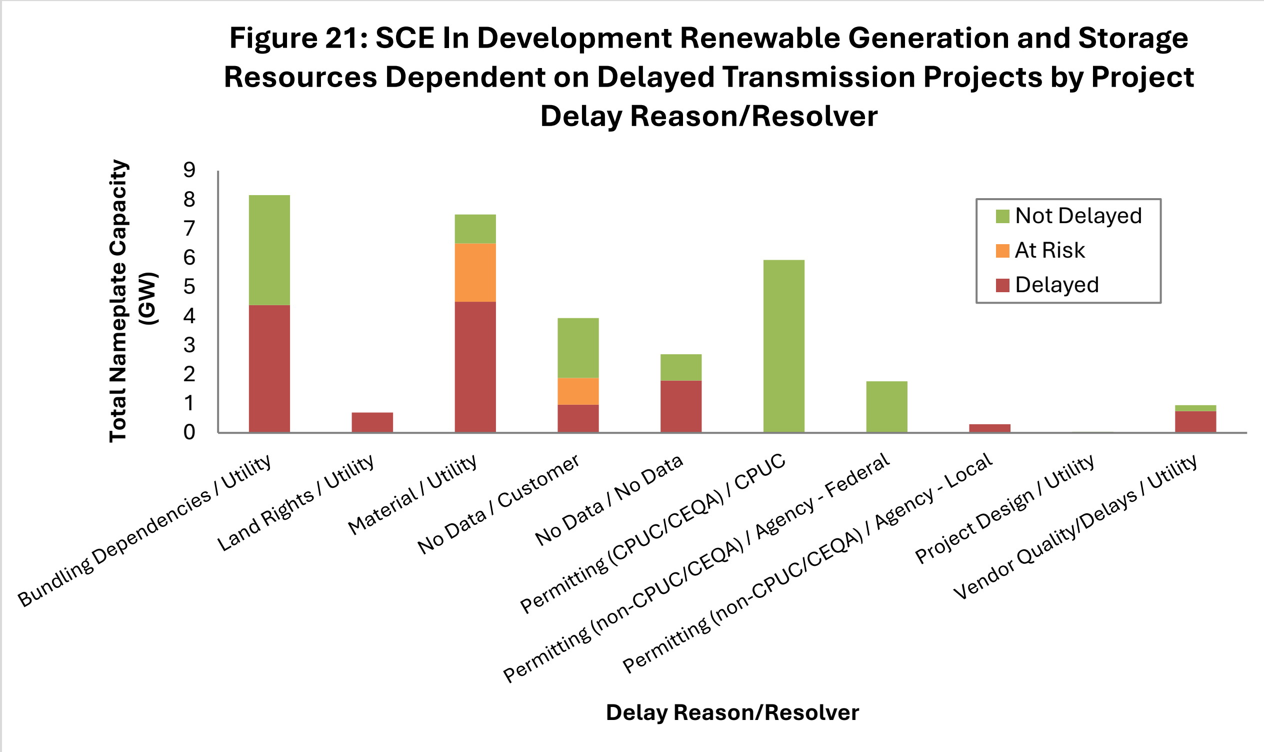


Figure 21: SCE In Development Renewable Generation and Storage Resources Dependent on Delayed Transmission Projects by Project Delayed Reason/Resolver
PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

Delayed Transmission Projects with Largest Impacts on Renewable Generation and Storage Resources

Between PG&E and SCE, there are 13.24 GW of renewable generation and storage resources in development that have been delayed or are at risk of being delayed due to the delayed transmission projects they depend on. However, a large portion of this capacity is delayed or at risk due to a small number of "high impact" delayed transmission projects.

Top Three PG&E High Impact Projects Identified By CPUC Staff

Table 49 below lists the top three PG&E projects in terms of most dependent Delayed and At Risk renewable generation and storage resource capacity.

Table 49: PG&E High Impact Transmission Projects		
PG&E Transmission Project	**Total Capacity Delayed (MW)**	**Total Capacity At Risk (MW)**
Vaca Dixon Substation 230 kV Circuit Breakers 442, 452 and 462 overstress	450	900
Q1496 Descendant Ranch (multiple upgrades)	500	0
BORDEN-GREGG upgrades	232	0

Table 49: PG&E High Impact Transmission Projects
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

Top Three PG&E High Impact Projects Identified By PG&E

PG&E's SB 1174 narrative statement also listed and described the top three delayed transmission projects PG&E considers to have the greatest impact on GW of renewable energy and storage resources. One of these transmission projects (Vaca Dixon substation) was also identified by CPUC staff and shown in the table above. The other two high impact transmission projects identified by PG&E are:

1) Conversion of Midway Substation 230 kilovolt (kV) Bus D to Breaker-and-a-Half to install bus reactors and Remedial Action Scheme: PG&E states that this project has experienced bundling dependency delays, with the potential to impact 15.95 GW. On mitigation PG&E states that "To address the delay, construction sequencing and buying equipment earlier will curtail the long-term delays and construction impacts."

   PG&E reports 16 resources as dependent on the Midway Substation conversion, but information on only 3 of these resources is found in the "Generation Reporting" tab of PG&E's SB 1174 data template. This is why the Midway Substation conversion is not featured in table 49 above. As of the writing of this report, 6 of the 16 in development resources that depend on the Midway Substation conversion do not have an executed interconnection agreement and 2 have withdrawn from the queue. Given the large number of early-stage resources that depend on this project; PG&E, CPUC staff, and other stakeholders should prioritize tracking the Midway Conversion project to ensure that it is completed without further delays that could put up to 16 GW of early-stage resources at risk.

2) The Gates 230 kV Reactors Bus E-F (Reliability Network Upgrade 1596): PG&E states that "The primary delay was due to the supply chain triggering an 11 months behind with an impact of 2 GW. To address the delays PG&E will be shifting material from another project that did not need the material as early and coordinate with said projects so that their material arrives on time to not create further delays". This project is not featured in table 49 above because no resources are reported as dependent on this upgrade on the "Transmission Delay Reporting" tab in PG&E's SB 1174 data template. A related reported project labeled "Gates Bus Section E" has 20 dependent resources. But transmission project "Gates Bus Section E" is marked by PG&E as "operational" so it was not included in analysis presented in table 49 above.

   This project is one example of projects with cascading delays triggered by supply chain constraints that PG&E, CPUC, and other stakeholders should track.

Top Three SCE High Impact Projects Identified By CPUC Staff

Table 50 below lists the top three SCE projects in terms of most dependent Delayed and At Risk renewable generation and storage resource capacity.

Table 50: SCE High Impact Transmission Projects		
SCE Transmission Project	**Total Dependent Delayed (MW)**	**Total Dependent At-Risk (MW)**
Lugo-Victorville 500 kV Transmission Line Upgrade	2,567	0
Devers-Valley No.1 500 kV Line Upgrade	2,300	0
San Bernardino-Vista 230 kV 1 Line Upgrade	1,400	0
Mesa - Mira Loma 500 kV UG Third Cable	1,400	0
Lugo-Victorville Centralized RAS	1,070	0
ED&P scope of work for 500kV Gen-Tie TOT905/Q1647 Angora Solar Farm	700	0
Gracesol Substation: Colorado River Substation-(IRNU-Shared) - TOT1006 (Q1761) Grace Energy Center	500	0

Table 50: SCE High Impact Transmission Projects
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

Table 50 highlights the large volume of SCE resources expected to be delayed or that are at risk of delay due to delays to critical upgrades like Lugo-Victorville 500 kV. It will be important for PTOs, CPUC, and other stakeholders to track these high impact projects going forward to prevent further slippage of their in-service dates. Lugo-Victorville in particular has experienced multiple years of delays and is currently being impacted by long lead-time material procurement and outage coordination issues between SCE and Los Angeles Department of Water and Power (LADWP), both of whom have scope on the project. As of the writing of this report SCE and LADWP are working closely to coordinate outage windows and bring in Lugo-Victorville's in-service date. Currently 2,567 MW of reported in-development resources are expected to be delayed behind Lugo-Victorville, with another 3,650 MW that could become delayed if Lugo-Victorville's in-service date continues to slip.

Top SCE High Impact Projects Identified By SCE

SCE's SB 1174 narrative statement also listed and described the top four delayed transmission projects SCE considers to have the greatest impact on GW of renewable energy and storage resources. Three of these resources (Lugo-Victorville, Devers-Valley, and San Bernardino-Vista) were also identified by CPUC staff and are included in table 50 above. The fourth project SCE identified as highest impact is the Eldorado-Lugo-Mohave RPS upgrade. This project's current planned in-service date is June 2025. SCE lists "Permitting (CPUC/CEQA)" as the reason for delay for this upgrade, but this project experienced significant delays associated with completion of the NEPA document by the BLM and National Park Service. There was also an amended application during the permitting process. Additionally, the project was constructed within the Mojave National Preserve which likely resulted in a lengthier federal process. CPUC prepared a Mitigated Negative Declaration for the project timed to sync up CPUC's CEQA process with the NEPA process.

Part 5: Permitting Analysis

In this year's assessment CPUC staff requested information from the PTOs about the permitting status of transmission projects and categorized the permitting reason for delay into two reasons: Permitting (CPUC/CEQA) and Permitting (non-CPUC/CEQA). The purpose of this split is to differentiate between project delays associated with state level permitting (specifically CPUC related permitting), and other federal or local permitting beyond CPUC's jurisdiction.

CPUC and CEQA Status for Each Transmission Project Delayed by Permitting (CPUC/CEQA)

PG&E reported 42 transmission projects delayed due to Permitting (CPUC/CEQA) yet there was no information given (N/A) for CEQA Status and CPUC Status. This lack of data means that CPUC staff are unable to examine the current permitting status of these projects to look for any trends associated with permitting delays.

Of the three SCE transmission projects delayed due to Permitting (CPUC/CEQA), only one (Eldorado-Lugo-Mohave RPS Upgrade) included information on its Final Certified and Approved CEQA and CPUC permitting status.

The overall lack of data on projects delayed due to Permitting (CPUC/CEQA) makes it difficult to determine the causes and parties involved with these delays. In future SB 1174 assessments, CPUC staff will work with the PTOs to get more complete transmission permitting status data.

Table 51: Transmission Projects Delayed Due to Permitting		
	PG&E	**SCE**
Permitting (CPUC/CEQA)	42	1
Permitting (non-CPUC/CEQA)	25	2

Table 51: Transmission Projects Delayed Due to Permitting
Data Source: PG&E, SCE 2025 SB 1174 Data Request (within their 2025 Draft RPS Procurement Plans)

PG&E reported more transmission projects with permitting related delays than SCE. This is at least in part because PG&E's data tended to break larger projects into smaller sub-projects. Overall, there does not appear to be a clear trend in the number projects delayed because of Permitting (CPUC/CEQA) versus Permitting (non-CPUC/CEQA).

Part 6: Mitigation Efforts on Transmission Project Delays

Within their 2025 Draft RPS Procurement Plans, the PTOs described mitigation efforts and business process improvements from the twelve months prior to the 2025 Draft RPS Procurement Plan due date, to address the most significant reasons for delays to transmission in-service dates. Additionally, the PTOs provided details on mitigation efforts and business process improvements to be undertaken over the next twelve months (July 2025 to July 2026) to address the most significant reasons for delays to transmission in-service dates.

Overall, the PTOs provide some insight into previous and future mitigation efforts for some of the common delay reasons discussed in the assessment, including Material and Permitting-related delays. However, PG&E does not mention any specific mitigation efforts to address Bundling Dependencies or Project Design, which are the top two delay reasons for transmission projects tied to the most dependent generation and storage resources (2.6 GW and 1.2 GW). SCE also does not provide any specific mitigation efforts to address transmission projects delayed for Bundling Dependencies, which is the delay reason tied to the second most dependent generation and storage resources (4.4 GW).

PG&E

In PG&E's SB 1174 narrative statement PG&E discusses workforce availability and permitting regarding transmission project delays and related mitigation efforts taken during the previous twelve months. While not described as a primary delay reason for any transmission projects, PG&E recognizes workforce availability as a contributing factor to delays and has implemented proactive measures to optimize available labor resources.

PG&E identifies Customer as the delay resolver in 49 percent of delayed projects, and states that it supports customers with Pre-submission Permitting/Environmental review, Customer Design Package Review, Utility and Telco Coordination Dependencies and issues and clearance sequencing.

To address transmission and network upgrade delays in 2025, PGE reports improved processes around ordering long-lead materials to shorten the time to order these materials. PG&E states that it has freed up investment capital to advance project funding to allow earlier procurements to combat long lead-times. These mitigation efforts address Materials, which was identified by PG&E as a delay reason for 3 percent of delayed transmission projects but is not a significant delay reason for RPS or storage resources. No other mitigation efforts are discussed.

SCE

SCE reports that it has implemented targeted mitigation efforts and business process improvements to address delays to interconnection in-service dates. In SCE's narrative template SCE states that generally, SCE does not mitigate a specific delay reason, apart from materials and workforce availability, but several changes to their organization will streamline internal processes and improve customer experience and communication.

SCE states that its efforts generally focus on materials as a delay reason and improving delays with the resolver customer. To address materials delays, SCE has executed a sourcing plan using a 5-year forecast and negotiated contracts with manufacturers to reserve production slots for power transformers and circuit breakers. SCE plans to have enough circuit breakers in the ordering cycle to reduce the waiting time for customer generator interconnection by half. SCE has also addressed workforce availability by hiring six additional technical professionals but notes that workforce shortages are more closely tied to timing and sequencing of tasks.

SCE has reviewed its Centralized Remedial Action Scheme (CRAS) process and reduced the overall schedule from 36 months to 30-33 months and improved overall workflow efficiency. SCE has also identified customer-driven milestones which has improved communication and increased certainty of project scope. SCE submitted its FERC Order No. 2023 compliance filing with an effective date of August 15, 2024, and new Wholesale Distribution Access Tariff (WDAT) requirements for QC15 projects. SCE states that, "these changes will allow SCE to streamline resource allocation, enhance scheduling accuracy, and allow for more focused and efficient execution of interconnection studies and stakeholder coordination".

SCE notes that it has no control or influence over customer related delays and activities, but it works with customers by helping them to understand requirements through an updated interconnection handbook, proactively ordering common circuit breakers, and establishing most effective interconnection points. Permitting timelines and delays are heavily dependent on the customer's level of expertise and the overall complexity of the project. SCE ensures that its scope of work is accurately reflected in environmental documentation.

To address transmission and interconnection delays to in-service dates in 2025, SCE has reorganized teams responsible for initiating generator interconnection agreements and managing contracts after execution, eliminating multiple touch points and hand-offs. SCE notes that FERC accepted CAISO's second 2023 IPE Track 2 filing which includes requirements for Shared Network Upgrades (SNU), which will expedite construction of SNUs. CAISO also submitted its 2023 IPE Track 3 filing, which would create an intra-cluster prioritization process for Reliability Network Upgrade projects with long lead-times.

SCE also continues to actively enhance its Grid Interconnection Processing Tool to improve data quality and tracking for both CAISO and WDAT Interconnection Requests. These improvements address delays with customers as the resolvers, which account for almost 20 percent of delay resolvers reported by SCE.

Part 7: Findings and Recommendations

Transmission project delays are very common in the data reported by the PTOs and the reasons are complex. This assessment attempts to identify the core reasons for the project delays and their impact on renewable generation and storage necessary to meet growing demand and California's GHG reduction goals. From this assessment, CPUC staff have been able to determine the following findings and related recommendations.

Findings

The key findings from this 2025 SB 1174 systemwide assessment are:

- For the second year in a row SDG&E's SB 1174 data contains deficiencies which make it unusable in this assessment: SDG&E's data does not distinguish between original and current in-service dates, and SDG&E staff misunderstood the scope of transmission projects and resources that they are required to report on. SDG&E staff are actively cooperating with CPUC staff to correct these deficiencies, but these corrections will arrive too late to be included in this assessment. SDG&E will need to address these deficiencies for the 2026 SB 1174 data request and assessment.

- The majority of PG&E and SCE in-development transmission projects have been delayed past their original ISDs at 63 and 70 percent respectively, with 64 percent of reported in-development transmission projects being delayed overall.
- For reported transmission projects that became operational between January 1, 2020 and March 31, 2025, 45 and 93 percent were delayed for PG&E and SCE respectively, with 50 percent being delayed overall.
- For PG&E, most transmission projects were delayed due to bundling dependencies (101) and the second most projects were delayed due to project design (87). For SCE, no data, or no delay reason, was provided for a large number of their delayed transmission projects (24). However, for projects with delay reasons listed, most projects were delayed due to bundling dependencies (16), with material (14) and project design (11) a close second and third. It is unclear why SCE did not provide delay reasons for 24 projects, however SCE attributed the resolving party to all those delayed projects as the customer. As such, it is possible SCE did not have insight into the reason for the delay.
- PG&E only identified two delay resolvers for all delayed transmission projects: itself (190 or 51 percent) and its customers (180 or 49 percent). SCE identified multiple parties as resolvers for delayed transmission projects. The majority were attributed to SCE itself (utility) (45 or 59 percent) with the rest being attributed to other parties (21 or 28 percent). Additionally, SCE provided no resolver for 10 projects.
- For PG&E, the longest median delay time was for permitting (CPUC/CEQA) where PG&E (utility) was the resolver (121 months or 10.1 years). This extremely long delay is due to the Estrella Substation project, whose permitting took significantly longer than usual due to public controversy surrounding the need for the project and the evaluation of non-wire alternatives in the project's CEQA document. CPUC staff note that the delay time of this outlier project is not indicative of typical CPUC and CEQA permitting times.
- Overall, median delay times were long for almost all delay reasons when PG&E was the resolving party. Project design, land rights, and bundling dependencies when PG&E is the resolver also displayed significant median delay times at 36 months (3 years), 34 months (2.83 years), and 33 months (2.75 years) respectively.
- For SCE, transmission projects delayed due to permitting (non-CPUC/CEQA) and needing resolution from a federal agency has the longest median delay time at 110 months (9.17 years). This delay time is attributed entirely to Lugo-Victorville RAS which is likely stalled due to ongoing delays on the Lugo-Victorville 500 kV line. BLM is the lead NEPA permitting agency for this RAS project, but the project's relationship to Lugo-Victorville 500 kV line is most likely the true driver of RAS work delay.
- SCE's data show that there are several delay reason and resolver combinations that have a median delay time that is longer than 36 months (3 years), including permitting (non-CPUC/CEQA)/agency-local, permitting (CPUC/CEQA)/CPUC, and bundling dependencies/utility. Of note, there is also a long median delay time for projects delayed by SCE's customer as the resolver (40 months or 3.3 years), however no data was provided by SCE as to the

cause for the delays on these projects. Also, projects delayed due to weather have a significant median delay time (54 months or 4.5 years), but SCE did not attribute any resolvers to these types of delayed transmission projects.

- For PG&E and SCE, 1.8 GW (32 percent) and 10.1 GW (67 percent) respectively of RPS eligible resources dependent on delayed transmission projects are delayed or at risk of delay.
- For PG&E and SCE, 1.20 GW (42 percent) and 1.95 GW (52 percent) respectively, totaling 3.15 GW (47 percent) of storage resources dependent on delayed transmission projects have already been delayed or at risk of being delayed.
- There were a total of 449 delayed transmission projects reported with dependent renewable generation or storage resources.
- The PTOs reported that 81 (28 percent) in development renewable generation or storage resources are dependent on delayed transmission projects, representing 54 percent of the capacity (GW) of reported renewable generation or storage resources in development.
- For PG&E and SCE, 2.98 GW (35 percent) and 10.26 GW (77 percent) respectively of reported in development renewable generation and storage resources are delayed or are at risk of delay (totaling 13.24 GW or 35 percent).
- For PG&E, bundling dependencies as a delay reason has the most delayed dependent resources at 2.5 GW and the second most delayed and at risk of delay resources of any delay reason at 2.71 GW. Financing/utility has the most delayed and at risk of delay resources of any delay reason and resolver combination at 2.85 GW, with project design/utility at third most overall with 2.4 GW.
- For SCE, material/utility has the most delayed resources at 4.5 GW and the most delayed and at risk of delay resources of any delay reason and resolver combination at 6.5 GW. Bundling dependencies/utility has the second most delayed and at risk of delay resources at 4.39 GW.

Recommendations

From conducting this 2025 SB 1174 systemwide assessment on delayed transmission projects and their impact on renewable generation and storage resources, CPUC staff offer these recommendations:

1. Given that most transmission projects do not meet originally planned ISDs, PTOs should consider allocating more time within a project's early planning phase to determine more realistic ISDs. CAISO intends to lengthen its transmission planning process as part of changes to comply with FERC Order 1920[160], which may give PTOs a longer window to better evaluate the time needed to complete new transmission projects.
2. PTOs should consider longer timelines for all phases of transmission project development to avoid bundling dependencies, in which one project delay causes a chain reaction of delays in other dependent transmission projects. PTOs should put more resources into continuously tracking the changing dependencies between transmission projects and looking for bottlenecks and single points of failure that can impact multiple projects.
3. The CPUC actively tracks the highest impact transmission projects. CAISO, PTOs, and other state agencies and stakeholders should also track the transmission projects listed in tables 49 and 50 above

160 *See* https://www.caiso.com/documents/presentation-ferc-order-no-1920-mar-13-2025.pdf.

and those described within the PTOs' SB 1174 narrative statements. Delays to these transmission projects could be key points of failure and put future resources at risk.

4. PTOs should continue to engage in proactive procurement of long lead-time materials such as high voltage circuit breakers and transformers and specialized steel structures, and continue to develop and test methods to forecast demand for these materials while adjusting procurement volumes based on the results of interconnection cluster studies.
5. The status of transmission projects, the parties involved in permitting at the state, federal, and local levels, and the estimated time to complete permitting processes are often not well understood or documented by all stakeholders. Permitting timelines carry significant uncertainties, and the CPUC and PTOs need to continue to work together to better understand permitting risks and develop a consensus on solutions. PTOs should improve internal tracking of permitting timelines to produce more accurate estimates for these timelines within their transmission project development schedules.
6. The CPUC, CAISO, PTOs, and other state agencies should work closely to develop a consistent metric that identifies high impact transmission projects whose delay poses a high risk to system or local reliability, large amounts of capacity of in-development renewable energy and storage resources at risk of delay, and GHG reduction goals.
7. CPUC staff and PTOs should continue to consider additional ways to work more effectively to obtain better data on the permitting timelines of each transmission project (such as what is underway with the new CPUC General Order 131-E pilot program).

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 implements legislation and establishes program policy and rules through its decisions within its RPS rulemaking proceeding. Further, the CPUC makes compliance determinations, which are completed after the CEC verifies RPS-eligible procurement from renewable energy facilities. Enforcement actions, if necessary, are then taken to ensure that electricity retailers comply with CPUC rules and State law.

The CPUC's responsibilities in the implementation and administration 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 Procurement Plan elements include information on current renewables portfolio information, upcoming solicitation plans for renewable energy, and long-term planning for renewable energy procurement. The RPS Procurement 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 renewables 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)[161] which describes the amount of renewable electricity generated by every RPS-eligible facility. The CEC analyzes the WREGIS reports to verify the eligibility of the REC, the quantity of RECs created from each RPS-eligible facility, and retail sellers' RPS procurement claims 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 requirements 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 the 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.[162]

161 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).

162 *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.[163]

Procurement Quantity Requirement (PQR)

The PQR is based on the statutorily[164] set the 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.[165] The annual percentage target is multiplied by a retail seller's total retail sales in each year for a given compliance period to determine the retail seller's annual targets. The PQR for the compliance period is determined by summing the retail seller's annual targets for the 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.

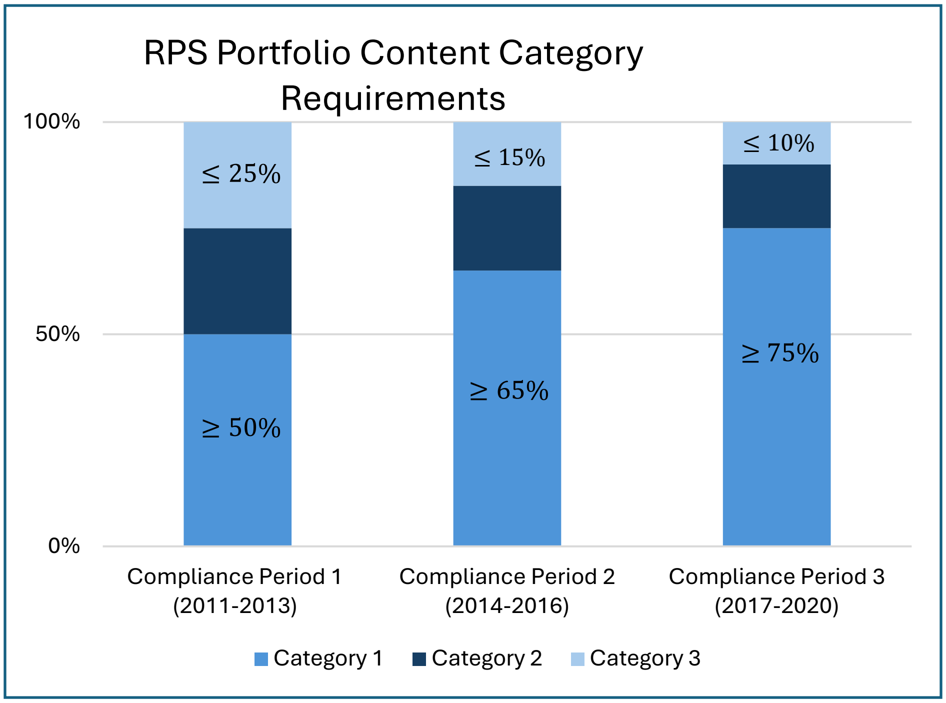
163 *See* Appendix A: About the RPS Program for more detail.

164 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.

165 *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.[166] 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 were adjusted across compliance periods until 2020, at which point they remain at those limits for each successive compliance period.



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.[167]

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.[168] For the first three compliance periods through 2020, 0.25 percent of a retail seller's total electricity portfolio was 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.

166 *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/industries-and-topics/electrical-energy/electric-power-procurement/rps/rps-compliance-rules-and-process/60-percent-rps-procurement-rules.
167 Pursuant to Public Utilities Code § 399.17 and 399.18.
168 *See* Public Utilities Code § 399.13(b) for additional information.

Appendix C – Summary of Accomplishments from January 2024 to October 2025

Month/Year	Accomplishments
January 2024	▪ CPUC approved BioMAT Tariff Modifications in compliance with AB 843. ▪ CPUC adopted the new RPS Order Instituting Rulemaking 24-01-017. ▪ CPUC adopted Resolution E-5297 approving a PPA for a zero-emissions product from a hybrid solar photovoltaic plus lithium-ion battery storage facility.
February 2024	▪ CPUC adopted D.24-02-047 adopting the 2023 preferred system plan.
March 2024	▪ CPUC adopted D.24-03-003, denying a BioRAM PFM.
April 2024	▪ CPUC notified retail sellers of the final determinations for the 2017-2020 Compliance period.
May 2024	▪ CPUC approved IOUs' recommendation to refrain from scheduling additional VAMO processes. ▪ CPUC adopted Resolution E-5313 approving SCE Renewables Mid-Term Reliability PPAs. ▪ CPUC adopted Resolution E-5318 approving SDG&E's RPS Solicitation Protocols. ▪ CPUC issued the 2024 Padilla Report on Costs and Cost Savings for the RPS Program to the Legislature, pursuant to Public Utilities Code § 913.3: https://www.cpuc.ca.gov/RPS_Reports_Data/. ▪ CPUC issued the Assigned Commissioner and Assigned Administrative Law Judge's Ruling issued identifying issues and a schedule of review for 2024 RPS Procurement Plans. ▪ CPUC issued a Scoping Memo for R.24-01-017 to set forth the initial schedule and issues for consideration in the RPS proceeding
June 2024	▪ Adoption of 2024 updated administratively set fixed avoided-cost rates for the ReMAT (Resolution E-5323). ▪ CPUC issued an Assigned Administrative Law Judge's Ruling requesting party comments on a Staff Proposal for clarifying RPS Procurement Plans confidentiality rules.
July 2024	▪ IOUs, SMJUs, CCAs, and ESPs submitted Draft 2024 RPS Procurement Plans. ▪ Staff conducted the RPS Annual Compliance Reports Webinar. ▪ CPUC adopted Resolution E-5333 approving SCE Renewables Mid-Term Reliability PPAs.
August 2024	▪ IOUs, CCAs, and ESPs submitted annual RPS Compliance Reports. ▪ CPUC adopted Resolution E-5343 approving PacifiCorp long-term REC contract with 3Degrees Group, Inc. ▪ CPUC adopted D.24-08-064 - Decision Determining Need for Centralized Procurement of Long Lead-Time Resources. ▪ CPUC launched a new RPS Database.
September 2024	▪ CPUC issued proposed Decision on Motions for Waiver of Renewables Portfolio Standard Program Requirement for Compliance Period 2017-2020.
October 2024	▪ CPUC adopted D.24-10-009 on Motions for Waiver of Renewables Portfolio Standard Program Requirement for Compliance Period 2017-2020.

November 2024	▪ CPUC issued annual SB 155 compliance notification letters.
December 2024	▪ CPUC issued the 2024 Annual RPS Report to the Legislature. ▪ CPUC adopted D.24-12-035 on the 2024 RPS Procurement Plans.
January 2025	▪ IOUs, SMJUs, CCAs, and ESPs filed Final 2024 RPS Procurement Plans
February 2025	▪ CPUC issued response to Governor Executive Order N-5-24.
March 2025	▪ CPUC approved Resolution E-5345 approving Pacific Gas and Electric Company RPS-eligible, Mid-Term Reliability Contracts. ▪ CPUC approve Resolution E-5375 denying Pacific Gas and Electric Company request to approve of sale of 2025-Delivery Renewable Energy Credits to NRG Business Marketing, LLC.
April 2025	▪ CPUC issued the Assigned Commissioner and Assigned Administrative Law Judge's Ruling issued identifying issues and a schedule of review for the 2025 RPS Procurement Plans. ▪ CPUC approved Resolution E-5376 which amended the BioRAM Program pursuant to Assembly Bill (AB) 2750. ▪ CPUC issued Reliable and Clean Power Procurement Program Staff Proposal.
May 2025	▪ Staff conducted the 2025 RPS Procurement Plans Webinar.
June 2025	▪ Adoption of 2025 updated administratively set fixed avoided-cost rates for the ReMAT (Resolution E-5392). ▪ CPUC issued the 2025 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/.
July 2025	▪ Staff conducted the 2025 RPS annual Compliance Reports Webinar. ▪ IOUs, SMJUs, CCAs, and ESPs submitted Draft 2025 RPS Procurement Plans. ▪ CPUC approved Central Coast Community Energy's BioMAT contract.
August 2025	▪ IOUs, CCAs, and ESPs submitted annual RPS Compliance Reports. ▪ CPUC adopted D.25-08-009, rejecting the IOUs' proposals for preapproved short-term RPS Transactions.
September 2025	▪ CPUC adopted D.25-09-012 approving SCE's sale of RPS-eligible Hydroelectric Power Plants to San Bernardino Valley Municipal Water District

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, Statutes 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 ensuring 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 of 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. The FIT program offers long-term contracts and price certainty for financing renewable energy investments. The RPS program has two FIT programs, ReMAT and BioMAT.

(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, exacerbated wildfire conditions. The millions of recently dead trees have created locally increased hazards related to fire and potential falling trees, and greatly impact 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 reduction 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 the 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.

(OBBBA) One Big Beautiful Bill Act was signed July 4, 2025, and imposes a rollback of federal renewable energy incentives, forcing a rapid recalibration of market expectations and project economics.

(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 who 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 seller's 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 utility's reliable capacity resources (supply) to meet customers' energy or system loads (demands) at all hours.

(RAM) Renewable Auction Mechanism: An RPS procurement process that 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 on 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 simultaneously with 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.

(RO/RTO) Regional Organization/Regional Transmission Organization: Through the Pathways Initiative, stakeholders across the west are developing the structure of an RO that would offer an expansive suite of electricity market functions across the largest possible footprint.

(SMJU) Small and Multi-Jurisdictional Utility: Investor-owned utilities that are considered small and multi-jurisdictional are 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 for 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
Pacific Gas and Electric Company (PG&E)
San Diego Gas & Electric Company (SDG&E)
Southern California Edison Company (SCE)
Small and Multi-Jurisdictional Utilities
Bear Valley Electric Service
Liberty Utilities
PacifiCorp
Electric Service Providers
3 Phases Renewables
BP Energy Retail Company (formerly EDF Industrial Power Services)
Calpine Energy Solutions
Calpine Power America
Commercial Energy of California
Constellation New Energy
NRG (previously Direct Energy Business)
Pilot Power Group
Shell Energy North America
Tiger Natural Gas
UC Regents
Community Choice Aggregators
Apple Valley Choice Energy
Ava Community Energy (formerly East Bay Community Energy)
Central Coast Community Energy
Clean Energy Alliance
Clean Power Alliance of Southern California
CleanPowerSF
Desert Community Energy
Energy for Palmdale's Independent Choice
King City Community Power
Lancaster Energy
Marin Clean Energy
Orange County Power Authority
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
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.