2023 RESOURCE ADEQUACY REPORT

Terra-Gen, LLC/Mortenson, Edwards & Sanborn Solar + Storage Project, 1300 MW

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CALIFORNIA PUBLIC UTILITIES COMMISSION
ENERGY DIVISION

A digital copy of this report can be found at:

https://www.cpuc.ca.gov/RA/

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AS	Ancillary Services	kW	Kilowatt
CAISO	California Independent System Operator	LCR	Local Capacity Requirement
CAM	Cost-Allocation Mechanism	LGIP	Large Generator Interconnection Procedures
CARB	California Air Resources Board	LOLP	Loss of Load Probability
CEC	California Energy Commission	LSE	Load Serving Entity
CCA	Community Choice Aggregator	LTPP	Long Term Procurement Plan
CHP	Combined Heat and Power	MCC	Maximum Cumulative Capacity
CPE	Central Procurement Entity	MOO	Must-Offer Obligation
CPM	Capacity Procurement Mechanism	MA	Month-Ahead
CPP	Critical Peak Pricing	MW	Megawatt
CPUC	California Public Utilities Commission	NERC	North American Reliability Corporation
CSP	Competitive Solicitation Process	NQC	Net Qualifying Capacity
DA	Direct Access	PCIA	Power Charge Indifference Adjustment
DG	Distributed Generation	PMax	Maximum capacity of a resource
DR	Demand Response	PMin	Minimum capacity of a resource
DRAM	Demand Response Auction Mechanism	PRM	Planning Reserve Margin
ED	Energy Division	QC	Qualifying Capacity
EE	Energy Efficiency	QF	Qualifying Facility
ELCC	Effective Load Carrying Capacity	RA	Resource Adequacy
EFC	Effective Flexible Capacity	RAR	Resource Adequacy Requirement
ESP	Electricity Service Provider	RMR	Reliability Must Run
ExD	Exceptional Dispatch	RPS	Renewable Portfolio Standard
FERC	Federal Energy Regulatory Commission	RUC	Residual Unit Commitment
GHG	Greenhouse Gas	SPD	Save Power Day
HE	Hour Ending	SFTP	Secure File Transfer Protocol
IOU	Investor-Owned Utility	TAC	Transmission Access Charge
IV	Imperial Valley		

1 EXECUTIVE SUMMARY

The Resource Adequacy (RA) program was developed in response to the 2000-2001 California energy crisis, an event that was fueled by capacity withholding of generators serving the California electric market. The program is designed to ensure that California Public Utilities Commission (CPUC) jurisdictional Load Serving Entities (LSEs)[1] have sufficient capacity to meet their peak load with a reserve margin that was initially set at 15%.[2] The RA program began implementation in 2006 and is intended to provide the energy market with sufficient forward capacity to meet peak demand and integrate renewables. This capacity includes System RA, Local RA, and Flexible RA, all of which are measured in megawatts (MWs). The CPUC sets the annual and monthly System, Local, and Flexible RA requirements for CPUC-jurisdictional LSEs.

This report provides a review of the CPUC's RA program, summarizing key aspects of RA program experience during the 2023 RA compliance year. While this report does not make explicit policy recommendations, it provides information relevant to the RA Rulemaking, R.23-10-011, and ongoing implementation of the RA program in California.

As described in the Program Overview Section, a key to establishing accurate RA capacity procurement obligations is accurate demand forecasts at both the LSE and aggregate level. The California Energy Commission (CEC) assesses the reasonableness of LSE-submitted forecasts, then makes demand side management adjustments, plausibility adjustments[3], and a prorated adjustment to each LSE's forecast to ensure

[1] CPUC jurisdictional LSEs include Investor-Owned Utilities (IOUs), Electricity Service Providers (ESPs), and Community Choice Aggregators (CCAs).

[2] Recent analysis had questioned the sufficiency of the 15% reserve margin to ensure reliability, and D.22-06-050 raised the reserve margin to 16% for 2023 and 17% for 2024. D.23-06-029 reaffirmed use of the 17% PRM for 2024 and 2025.

[3] If the CEC determines that the assumptions made for the load forecast are not plausible, the CEC may make a plausibility adjustment to account for a more plausible rate of customer retention.

that the total for all forecasts is within 1% of CPUC's portion of the CEC's adopted coincident managed demand forecast.

The following bullets provide a summary of the key highlights from this report.

- **2023 RA Obligation was Higher than 2022** due to both rising load forecasts and a higher Planning Reserve Margin (PRM).
  - The overall CEC-adjusted forecast for CPUC-jurisdictional LSEs had an expected peak in September 2023 of 42,192 MW, which represents a 4% increase over the peak forecast of 40,585 MW for September 2022.
  - As part of D.22-06-050, the Commission raised the PRM from 15% to 16% for 2023, contributing to a slight increase to LSEs' System RA obligations across all months.

- **LSE Compliance with RA Obligations**
  - **System Obligations Met:** In 2023, CPUC-jurisdictional LSEs collectively met their System RA obligations for all months. The 2023 peak demand (for CPUC-jurisdictional LSEs, after net load migration adjustments) was forecasted to occur in September 2023, at 42,192 MW. The RA obligation for September, including a 16% planning reserve margin (PRM) on top of peak demand, totaled 49,162 MW. Collectively, LSEs (including CPEs) procured 50,089 MW. For individual LSE compliance, see citation section below.
  - LSEs procured a monthly minimum of 32,487 MW. Physical resources, cost allocation mechanism (CAM) resources, reliability must-run (RMR) resources, and demand response (DR) resources, and imports contributed to this total.

- **Central Procurement Entity (CPE) Framework Implementation**
  - 2023 marked the first compliance year with full implementation of the Central Procurement Entity (CPE) framework for Local RA in PG&E and SCE service territories, pursuant to D.20-06-002 and subsequent decisions.

- **Actual Peak Demand in 2023**
  - CAISO's peak demand in 2023 was 44,226 MW on August 16, between 4:00 and 5:00 PM. This figure includes both CPUC-jurisdictional and non-CPUC-jurisdictional LSEs. About 90% of 2023 actual peak load, or approximately 39,800 MW, could be attributed to CPUC-jurisdictional LSEs. The 2022 CAISO peak remains the highest on record, at 51,479 MW on September 6, 2022.

- **Prices for Resource Adequacy**
  - **RA contract prices continued to increase**: Prices for System and Local RA increased significantly between 2022 and 2023, particularly for the summer months. The weighted average System RA price in September 2023 was $24.07/kW-month – a 93% increase from 2022.

- **Resource Adequacy Citations**
  - **Citations are Issued for Non-Compliance:** The CPUC's RA program obligates LSEs to acquire capacity to meet load and reserve requirements, consistent with Public Utilities Code 380. The CPUC issues citations or initiates enforcement actions when LSEs do not fully comply with RA program rules.[4]
  - **Citations in 2023:** In total, the CPUC's Enforcement Division issued 24 citations for 56 violations related to compliance year 2023 for a total of $24,388,462.
  - **New Citations Database:** The CPUC issued a new listing of all RA citations that includes all citations issued since 2011 through 2024. Pursuant to D.23-06-029, the following information is considered non-confidential and are included in the RA citation database: the type of RA deficiency, month of deficiency, deficiency amount (MW), and any points accrued.
  - **The RA Citations Briefing and RA Citations database** identifies the type of LSEs that had individual citations in 2023 (18 CCAs and 7 ESPs), including the number of violations (56), the number of MWs of deficiency (over 2,600 MW-months of deficiency), and the financial penalty amount of the citations issued for 2023 RA year violations (more than $24 million).[5]
- **Retail Electricity Suppliers: Emissions of Greenhouse Gases**
  - Senate Bill 1158 (SB 1158, 2022) directs the CPUC to review the total annual emission of greenhouse gasses (GHGs) and the annual GHG emissions

[4] Due to either a procurement deficiency (i.e., the LSE did not meet its RA obligations) or filing-related violations of compliance rules (e.g., files late, or not at all).

[5] The RA Citations Briefing and Database are available on the RA Penalties and Citations page, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-penalties-and-citations

intensity reported by each LSE to the CEC. As part of this new reporting implemented in 2023, the CPUC measured the total annual percentage of the Month-Ahead capacity requirement met by capacity contracted from RPS or zero-emitting resources.

- Total annual percentage varied widely between each LSE, ranging from 2.67% to 63.83%. Variation is due to a variety of factors, including the composition of each LSEs portfolio, with factors like the inclusion of energy storage systems contributing to higher values.

2 RA PROGRAM BACKGROUND

This section of the 2023 RA Report provides an overview of the RA Program Rules. Additional information about the RA Program Rules can be found in the RA Program Filing Guide.[6]

2.1 Resource Adequacy Program Requirements

The CPUC's RA program contains three distinct requirements:

- System RA requirements (effective June 1, 2006): ensure sufficient capacity is available to meet statewide peak demand.
- Local RA requirements (effective January 1, 2007): ensure that capacity is available within local transmission-constrained areas.
- Flexible RA requirements (effective January 1, 2015): ensure resources are available to meet intra-day variations in demand and net load.

Requirement	2023 Determination
System RA	Each LSEs CEC-adjusted forecast plus a 16% planning reserve margin
Local RA	Annual CAISO study using a 1-in-10 weather year and an N-1-1 contingency
Flexible RA	Annual CAISO study that currently looks at the largest three-hour ramp for each month needed to run the system reliably

[6] final-2023-ra-guide-clean-101821.pdf (ca.gov)

There are two types of filings: Annual filings (filed on or around October 31st) and Monthly filings (filed 45 calendar days prior to the compliance month). Commission staff evaluates LSE filings annually and monthly to ensure accuracy and completeness.

For annual filings, LSEs are required to make an annual System, Local, and Flexible compliance showing for the coming year:

- System RA: LSEs must demonstrate procurement of at least 90% of their obligation for the five summer months (May – September) of the upcoming compliance year.
- Local RA: Each LSE has a three-year forward Local obligation. LSEs must meet 100% of their Local requirement for years one and two, and 50% of their obligation for year three.
- Flexible RA: LSEs must demonstrate procurement of at least 90% of their Flexible RA obligations for all twelve months.

Each year, Local RA obligations are assigned for three compliance years: the current year, plus two years forward. Beginning with the 2023 compliance year, LSEs in the PG&E and SCE Local Distribution Areas were no longer required to meet 100% of Local RA obligations, as the Central Procurement Entity (CPE) assumed that responsibility.

For monthly filings, LSEs must demonstrate that they have procured 100% of their monthly System and Flexible RA obligation. Additionally, from July through December, LSEs must also show compliance with their revised Local RA obligations (adjusted for load migration).[7]

Showing	**Annual** (Filed on or around 10/31)	**Monthly** (Filed 45 days prior to compliance month)
System	LSE must demonstrate procurement of 90% of System RA obligation for the five summer months (May – September) of the coming compliance year.	LSE must demonstrate procurement of 100% of their monthly System RA obligation.
Local	For its three-year forward obligation, each LSE in the SDGE area must demonstrate	From July to December, LSE must demonstrate

7 LSEs serving load in PG&E and SCE's TAC area are not subject to revised local RA obligations.

	procurement of 100% of Local RA obligation for each month of compliance years one and two and 50% of Local RA obligation for year three.	procurement of their revised (due to load migration) Local RA obligation.
Flexible	LSE must demonstrate procurement of 90% of Flexible RA obligation for each month of coming compliance year.	LSE must demonstrate procurement of 100% of their monthly Flexible RA obligation.

Monthly and annual System RA requirements are based on load forecast data submitted annually by each LSE and adjusted by the California Energy Commission (CEC). Jurisdictional and non-jurisdictional LSEs must file historical hourly peak load data for the preceding year, and monthly energy and peak demand forecasts for the upcoming compliance year using a "best estimate approach" based on reasonable assumptions about load growth and customer retention.

The CEC reviews and adjusts these forecasts, which form the basis for the final LSE load forecasts used for Year-Ahead RA compliance. LSEs must also submit monthly load forecasts throughout the year to reflect load migration.

To establish the Year-Ahead load forecast, the CEC first evaluates the reasonableness of each LSEs' forecast based on a comparison with an LSE-specific benchmark derived from historical load data, load migration activity and temperature adjustments. LSE noncoincident peak forecasts may be adjusted based on this comparison. CEC then applies a coincidence adjustment. Coincidence factors are based on a statistical evaluation of each LSE's load at the time of California Independent System Operator (CAISO) monthly peak demand relative to the LSE's monthly peak demand. This metric adjusts the forecast to reflect the LSE's contribution to total load during CAISO system peaks.[8] Additionally, as specified in D.05-10-042, the CEC also makes downward adjustments to give LSEs credit for Public Goods Charge funded programs that are not already reflected in the LSE's forecast. The CEC's process ensures that the sum of all adjusted LSE forecasts remains within 1% of the CEC service area forecast. If the

[8] Adopted in D.12-06-025, Ordering Paragraph 4, Available at: Microsoft Word - 169718.DOC

aggregated LSE forecasts diverge more than 1%, the CEC makes a pro-rata adjustment to reduce the divergence to within 1%.

Using these adjusted forecasts, the CEC calculates monthly load shares for each transmission access charge (TAC) area. Energy Division uses these load shares to allocate DR, CAM, and RMR RA credits, and to determine each LSE's Flexible RA requirement. Local RA obligations are based on each LSE's September load share. The forecasts and allocations together determine both the annual and monthly System RA obligations.

In D.19-06-026, the Commission adopted Energy Division's proposal for a Binding Load Forecast process to lock in RA requirements based on load forecast assumptions that an LSE can reasonably control or predict, as well as the proposed plausibility review triggers. Under the adopted process, LSEs' initial Year-Ahead forecast will serve as the Binding Notice of Intent (BNI) for the next compliance year. To account for unforeseen circumstances or new or relevant information in the forecasting process, the CEC will extend the deadline for revisions of the initial forecasts to May 15. This forecast, once adjusted by the CEC, becomes binding – regardless of additional changes in an LSE's implementation to new customers – except for updates due to load migration.

The decision also adopted plausibility review triggers. If a forecast appears inconsistent with implementation plans or deviates from historical trends, LSEs may be required to provide documentation or revise forecasts to improve accuracy.[9]

2.2 Changes to RA Program for 2023

D.22-06-050 adopted System, Local, and Flexible RA requirements for the 2023 compliance year, and implemented several programmatic refinements and clarifications. These included an increase to the planning reserve margin (PRM) from 15% to 16%, refinements to RA resource availability hours and Maximum Cumulative Capacity (MCC) bucket structures, and continued implementation of the Central Procurement Entity (CPE) framework for Local RA. The Decision adopted Effective Load Carrying Capability (ELCC) values for wind and solar for the 2023 compliance year. The Decision considers a 2024 test year for the 24-hour framework prior to full

[9] D.19-06-026, p. 28-29.

program implementation for the 2025 Resource Adequacy year. The Decision adopted the CEC's load forecast proposal for the individual LSEs' hourly load forecast in the 24-hour framework. The Decision also adopted counting rules for various resources under the 24-hour framework.

Key updates for 2023 are summarized below:

2.2.1 Planning Reserve Margin Increase

Pursuant to D.22-06-050, beginning in 2023, the Commission increased the System RA Planning Reserve Margin (PRM) from 15% to 16%. This change was intended to ensure sufficient capacity in light of evolving reliability risks and load growth trends.

2.2.2 Changes to Maximum Cumulative Capacity Buckets

D.22-06-050 also adopted the following changes to the RA measurement hours and the Maximum Cumulative Capacity (MCC) Buckets. Effective in 2023, the RA measurement hours are:

- 5:00 PM – 10:00 PM for the months of March and April, and
- 4:00 PM – 9:00 PM for all other months.

As a result, the MCC Buckets were modified as follows:

Category	Availability	Maximum Cumulative Capacity for Bucket and Buckets Above
DR	Varies by contract or tariff provisions, but must be available Monday – Saturday, 4 consecutive hours between 4 PM and 9 PM, and at least 24 hours per month from May – September.	8.3%
1	Monday – Saturday, at least 100 hours per month. For the month of February, total availability is at least 96 hours. January – February, May – December, 4 consecutive hours between 4 PM – 9 PM. March – April, 4 consecutive hours between 5 PM – 10 PM.	17.0%
2	Every Monday – Saturday. January – February, May – December, 8 consecutive hours that include 4 PM – 9 PM. March – April, 8 consecutive hours that include 5 PM – 10 PM.	24.9%
3	Every Monday – Saturday. January – February, May – December, 16 consecutive hours that include 4 PM – 9	34.8%

Category	Availability	Maximum Cumulative Capacity for Bucket and Buckets Above
	PM. March – April, 16 consecutive hours that include 5 PM – 10 PM.	
4	Every day of the month. Dispatchable resources must be available all 24 hours.	100% (at least 56.1% available all 24 hours)

These adjustments further align the RA program with grid reliability needs during critical evening hours.

2.2.3 Transition to CPE for Local Procurement

Beginning with the 2023 RA compliance year, LSEs located in PG&E and SCE local TAC areas were no longer required to procure Local RA resources, due to the continued implementation of the Local RA Central Procurement Entity (CPE) framework adopted in D.20-06-002[10] and further clarified in subsequent decisions, D.20-12-006, and D.22-03-034. For local areas in the PG&E and SCE TAC areas, the CPE (PG&E and SCE) assumes full responsibility for procuring Local RA on behalf of all LSEs.

Accordingly, LSEs in PG&E and SCE service territories were not allocated Local RA obligations for 2023. The RA capacity produced by the CPE is reported and allocated separately, and Energy Division monitors sufficiency and cost allocation consistent with the adopted framework.

In D.20-06-002, the Commission adopted a hybrid procurement structure in which the CPE would "secure a portfolio of the most effective local resources, use its purchasing power in constrained local areas, mitigate the need for costly backstop procurement in certain local areas, and ensure a least cost solution for customers and equitable cost allocation." The hybrid framework allowed LSEs to voluntarily procure local resources to meet their system and/or flexible RA needs and count them towards the collective local RA requirements. An LSE that procures a resource that meets a local RA need may: (1) self-show the resource to the CPE to reduce the CPE's overall local

[10] D.20-06-002, available at https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M340/K671/340671902.PDF.

procurement obligation and retain the resource to meet the LSE's system or flexible RA needs, (2) bid the resource into the CPE's solicitation, or (3) elect not to show or bid the resource to the CPE and only use the resource to meet its own system and flexible RA needs. The Commission also provided that the CPE shall have discretion to defer procurement of a local resource to the CAISO's backstop mechanisms, rather than through the solicitation process, if bid costs are deemed unreasonably high. D.20-06-002 directed the CPEs to begin procurement in 2021 for 100 percent of the 2023 local requirements and 50 percent of the 2024 local requirements. In 2022, the CPE is responsible for procuring 100 percent of the three-year forward local requirements for 2023 – 2024 and 50 percent of the three year forward local requirement for 2025.

3 LOAD FORECAST AND RESOURCE ADEQUACY PROGRAM REQUIREMENTS

3.1 Yearly and Monthly Load Forecast Process in 2023

RA requirements for 2023 were developed according to the following schedule. LSEs have been able to revise their April annual load forecast for load migration since 2012, and revised annual forecasts have been required starting in 2018.[11] The 2023 revised annual forecasts were due on August 15, 2022. These revised forecasts informed the final 2023 Year-Ahead allocations and requirements and were used by LSEs in the Year-Ahead filing process. CPUC staff sent initial allocations to LSEs on July 20, 2022, and final allocations to LSEs on September 22, 2022.

LSEs file historical load information	March 14, 2022
LSEs file 2023 Year-Ahead load forecast	April 18, 2022
LSEs receive 2023 Year-Ahead RA obligations	July 20, 2022
Final date to file revised forecasts for 2023	August 15, 2022

[11] D.17-06-027, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M192/K027/192027253.PDF.

LSEs receive revised 2023 RA obligations	September 22, 2022

To determine monthly RA requirements, the CPUC allows LSEs to revise their annual load forecasts on a monthly basis to account for load migration.[12] This process was adopted in D.05-10-042[13] and is further described in the 2023 RA Guide.[14] Specifically, LSEs must submit a revised forecast prior to each compliance filing month.[15] These monthly load forecast adjustments are solely intended to reflect customer load migration between LSEs, not to account for changes in demographics or electrical conditions.

Pursuant to D.10-06-036,[16] LSEs must submit any monthly forecast revisions at least 25 days prior to the Month-Ahead compliance filing due date. These forecasts are submitted to both the CEC and CPUC for review. The CEC evaluates the revised forecasts and the associated customer migration assumptions. The updated monthly load forecasts serve to refine the Year-Ahead forecasts and inform each LSE's monthly RA obligation.

Energy Division also uses the monthly revised forecasts to recalculate LSE load shares, which are then used to reallocate CAM and RMR credits on a quarterly basis. These revised load forecasts also inform the Local true-up process discussed in Section 3.5.2.

[12] This rule was changed prospectively in Decision (D.) 23-06-029 to only allow for one biannual update to the annual load forecasts.

[13] D.05-10-042 available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/50731.PDF.

[14] This rule was changed prospectively in Decision (D.) 23-06-029 to only allow for one biannual update to the annual load forecasts.

[15] Annual RA Filing Guides are available on the CPUC website: Resource Adequacy Compliance Materials (ca.gov).

[16] Available at https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/119856.PDF, Ordering Paragraph 6.

3.2 Yearly Load Forecast

Table 1 shows the aggregate load forecasts submitted by LSEs for 2023, along with the adjustments made by the CEC across the three IOU service areas.[17] These adjustments include:

- Plausibility and migrating load adjustments,
- Demand side management adjustments (including energy efficiency (EE), distributed generation (DG), and demand response (DR)), and
- A pro rata adjustment to align the sum of all LSE forecasts within 1% of the CEC's overall service area forecast.

The forecast also includes a coincidence adjustment, which calculates each LSE's expected contribution towards the CAISO peak.

The final CEC-adjusted forecast for CPUC-jurisdictional LSEs projected a system peak of 42,192 MW in September 2023, representing a 3.9% increase from the September 2022 peak forecast of 40,585 MW.[18]

Table 1. 2023 Aggregated Load Forecast Data (MW) - Results of Energy Commission Review and Adjustment to the 2023 Year-Ahead Load Forecast

Element	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Submitted LSE Forecast	26,854	25,881	25,445	26,749	30,976	36,229	40,488	40,918	40,809	33,384	26,748	26,953
Adjustment for Plausibility and Migrating Load	2,179	2,034	1,383	2,564	2,606	2,257	1,919	1,867	2,208	1,067	1,614	2,869
EE/DG/DR Adjustment	(107)	(122)	(127)	(120)	(685)	(173)	(233)	(234)	(204)	(141)	(555)	(530)
Pro Rata Adjustment	695	658	612	922	709	1,128	480	510	702	761	925	763

[17] Because the historical and forecast data submitted by participating LSEs contain market-sensitive information, results are presented and discussed in aggregate.

[18] The 2022 RA report can be found at: 2022 Resource Adequacy Report (ca.gov)

Non-Coincident Peak Demand	**29,621**	**28,451**	**27,312**	**30,115**	**33,607**	**39,441**	**42,654**	**43,061**	**43,516**	**35,071**	**28,732**	**30,055**
Coincidence Adjustment	(929)	(714)	(831)	(847)	(1,149)	(1,557)	(1,799)	(1,618)	(1,324)	(895)	(860)	(633)
Final Load Forecast Used for Compliance	**28,692**	**27,737**	**26,481**	**29,268**	**32,458**	**37,884**	**40,855**	**41,443**	**42,192**	**34,176**	**27,873**	**29,422**

Source: CEC Staff.

3.3 Year-Ahead Plausibility Adjustments and Monthly Load Migration

Table 2 presents the aggregate monthly plausibility adjustments applied by the CEC to all LSEs from 2013 through 2023. It also shows the 2023 monthly plausibility adjustments as a percentage of the corresponding CEC-adjusted Year-Ahead forecast for 2023.

In 2023, the CEC's plausibility adjustments increased the load forecast for all months. The 2023 monthly plausibility adjustments, as a percentage of each month's adjusted Year-Ahead forecast ranged from 3.12% in October to 9.75% in December.

Plausibility adjustments generally reflect discrepancies between an LSE's forecast assumptions and the CEC's assumptions regarding economic growth, weather sensitivity, and customer migration or retention. The CEC develops a reference forecast for each LSE based on historical loads and load migration data and applies and adjustment when an LSE's forecast deviated significantly from this reference. IOU forecasts are also adjusted to align the total forecast for the IOU service area with the CEC's service area-level forecast and estimated levels of departing load.

Table 2. CEC Plausibility Adjustments, 2013-2023 (MW)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2013	0	56	63	60	61	95	99	(985)	249	102	70	64
2014	61	67	69	74	77	78	81	(147)	89	88	79	71
2015	(218)	(355)	(51)	(126)	(7)	(298)	(205)	(481)	(311)	(307)	(260)	(199)
2016	(46)	(55)	(95)	(130)	(227)	(357)	(27)	(379)	84	(195)	(293)	80
2017	152	(98)	191	(869)	(401)	(820)	(888)	(1,462)	170	(431)	511	603
2018	776	894	1,053	2,523	4,864	3,906	4,460	3,633	5,286	3,257	2,722	2,635
2019	(104)	31	(181)	1,510	1,803	3,884	2,606	(586)	4,784	3,962	137	(349)
2020	811	873	514	1,362	1,895	1,821	1,673	1,522	1,570	786	870	871

2021	1,058	1,105	746	938	1,970	1,696	1,407	1,409	1,653	1,365	592	1,193
2022	1,341	1,644	828	1,636	2,306	2,206	1,710	922	1,707	2,090	1,329	2,357
2023	2,179	2,034	1,383	2,564	2,606	2,257	1,919	1,867	2,208	1,067	1,614	2,869
2023 Plaus. Adj./Load	7.59%	7.33%	5.22%	8.76%	8.03%	5.96%	4.70%	4.51%	5.23%	3.12%	5.79%	9.75%

Source: Year-Ahead CEC load forecasts, 2013-2023.

Monthly load forecasts, adjusted for load migration, form the basis of monthly RA obligations. Table 3 presents the total monthly load forecasts and associated load migration adjustments for 2023. Net monthly adjustments from the Year-Ahead (YA) load forecast to the final monthly forecasts used in RA compliance filings were relatively small. The largest monthly adjustment in percentage terms was an increase of 0.8% in October 2023. In megawatt terms, net adjustments ranged from -18 MW in February to 272 MW in October.

Because load migration is defined as the transfer of customers from one LSE to another, net adjustments should generally sum to zero. However, discrepancies between the forecasts of LSEs gaining and losing customers can result in non-zero net adjustments. In recent years, the CPUC and CEC have taken steps to improve coordination between LSEs during the forecast process to reduce these discrepancies.

Table 3. Summary of Load Migration Adjustments in 2023 (MW)

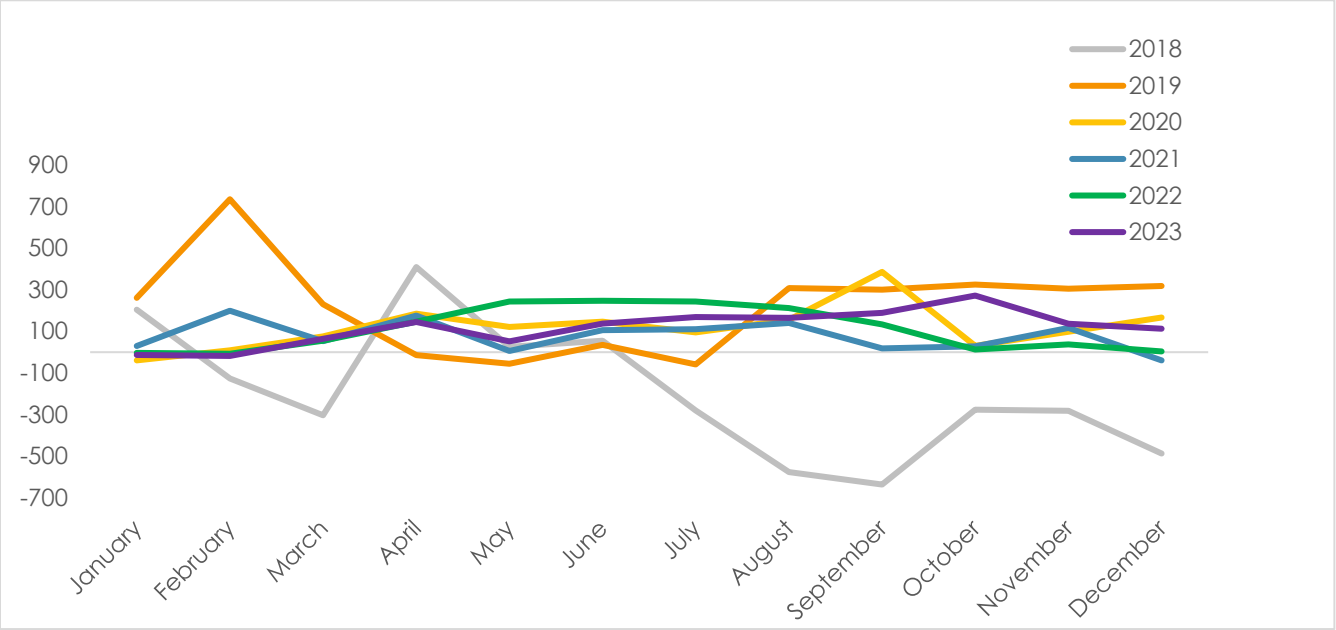
Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Final YA Load Forecast	27,867	27,175	26,145	28,525	32,059	36,738	39,585	39,864	40,585	32,866	27,461	28,874
Monthly Adjustments	(13)	(18)	65	145	52	137	169	165	189	272	137	113
Final Forecasts in Monthly RA Filings	27,864	27,167	26,201	28,672	32,303	36,985	39,828	40,077	40,718	32,879	27,499	28,878

Monthly Adjustments/ Final YA Load Forecast	-0.01%	-0.03%	0.21%	0.51%	0.76%	0.67%	0.61%	0.53%	0.33%	0.04%	0.14%	0.01%

Source: Load forecast adjustments submitted to the CEC and CPUC in 2023.

Figure 1 illustrates monthly net load migration from 2018 through 2023. Monthly net migration remained below 800 MW (roughly 3% of total load) during this period. Load migration in 2023 (shown in purple) was relatively low throughout the year. The largest net migration occurred in October 2023, totaling 272 MW (or 0.8% of total load).

Figure 1. Net Load Migration Adjustments per Month (MW), 2018-2023



Source: Monthly forecast adjustments submitted by LSEs, 2018-2023

3.4 System RA Requirements for CPUC-Jurisdictional LSEs

CPUC-jurisdictional LSEs met their collective System RA requirements for every month of 2023. The total RA resources procured exceeded the total System Resource Adequacy Requirement (RAR) by 1.6% to 7.0%, depending on the month.[19]

Table 4 presents the total monthly RA procurement for CPUC-jurisdictional LSEs and CPEs in 2023, broken down by resource category:

- Physical resources within the CAISO control area (including CAM resources),
- Demand Response (DR),
- Capacity procurement mechanism (CPM) and Reliability must run (RMR) resources, and
- Imports

- CAM resources are deducted from the RA requirement of non-IOU LSEs, while IOUs receive a corresponding increase in their RA requirements, which is offset by including the full CAM capacity in their filings on behalf of all benefiting customers.

Physical resources include all supply within the CAISO control area and CPE procurement (allocated as a credit to all CPUC-jurisdictional LSEs), and CAM resources are reported separately as a subset of this category. The monthly RA obligation includes each LSE's load forecast plus a 16% PRM. For DR resources, including those procured through the Demand Response Auction Mechanism (DRAM), a 9% PRM is applied.[20]

[19] System requirements include a 16% Planning Reserve Margin above jurisdictional LSEs' aggregate monthly peak forecast.

[20] D.21-06-029 (OP 12) removed the 6% PRM adder associated with ancillary services and operating reserves from demand response resources, effective beginning in the 2022 compliance year. The 9% component of PRM adder associated with forced outages was retained.

Table 4. 2023 RA Filing Summary - CPUC-jurisdictional Entities (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
RAR without DR,CAM, & RMR	33,268	32,154	30,793	34,119	37,711	44,105	47,587	48,266	49,162	39,960	32,491	34,260
CAM	7,134	7,085	7,084	7,190	6,551	5,164	5,198	3,858	3,860	3,797	4,207	4,233
Phys. Res. (w/ CAM)	30,460	29,454	28,383	30,681	33,613	39,440	41,122	40,696	41,578	35,298	28,619	30,729
CPE Procurement	1,405	1,404	1,402	1,398	1,884	2,349	2,341	2,888	2,898	2,921	2,931	2,942
Import (Resource Specific)	789	978	1,527	1,231	1,493	1,581	1,666	1,684	1,758	1,401	847	892
Import (Unspecified)	19	19	19	75	159	641	1,126	1,225	2,046	487	100	100
Total Imports	808	997	1,546	1,306	1,652	2,222	2,792	2,909	3,804	1,888	947	992
DR plus 9% PRM	987	1,031	1,002	1,202	1,320	1,517	1,609	1,647	1,656	1,348	1,142	1,004
RMR	154	154	154	154	154	154	154	154	154	154	154	154
CPM	0	0	0	0	0	0	0	0	0	0	0	0
Total	33,814	33,040	32,487	34,741	38,623	45,682	48,018	48,294	50,089	41,610	33,792	35,820
Total/RAR	**101.6%**	**102.8%**	**105.5%**	**101.8%**	**102.4%**	**103.6%**	**100.9%**	**100.1%**	**101.9%**	**104.1%**	**104.0%**	**104.6%**

Source: LSE Monthly RA Filings.

In 2023, total committed RA resources ranged from 32,487 MW in March to 50,089 MW in September. Between 89% and 94% of all committed RA capacity (including CAM and CPE CAM procurement) was procured by LSEs and CPEs from unit-specific, physical resources located within the CAISO control area. This percentage was higher in off-peak months and lower in peak months, when CAISO resources were supplemented by imports. Unspecified Imports accounted for 0.1% to 4.1% of total capacity, and Demand Response made up 2.8% to 3.5%. CAM and RMR resources made up between 8.0% and 22.3% of total capacity procured. Including CPE CAM in CAM totals and RMR, resources made up between 13.8% to 26.6%. Together, these resources enabled CPUC-jurisdictional LSEs to meet between 100.1% and 105.5% of their collective procurement obligations during the summer months.

As of the end of 2023, the 2022 CAISO peak remains the highest on record, surpassing the previous peak set in 2006.[21] The actual peak demand of 51,479 MW, which includes CPUC-jurisdictional and non-CPUC jurisdictional LSEs, occurred on September 6, 2022,

[21] http://www.caiso.com/documents/californiaisopeakloadhistory.pdf

just before 5 pm.[22] In 2023, the highest recorded peak demand was 44,226 MW on August 16 in the same hour, which is approximately 7,500 MW lower than the 2022 peak.[23] Around 90% of 2023 actual peak load, or about 39,800, could be attributed to CPUC-jurisdictional LSEs.

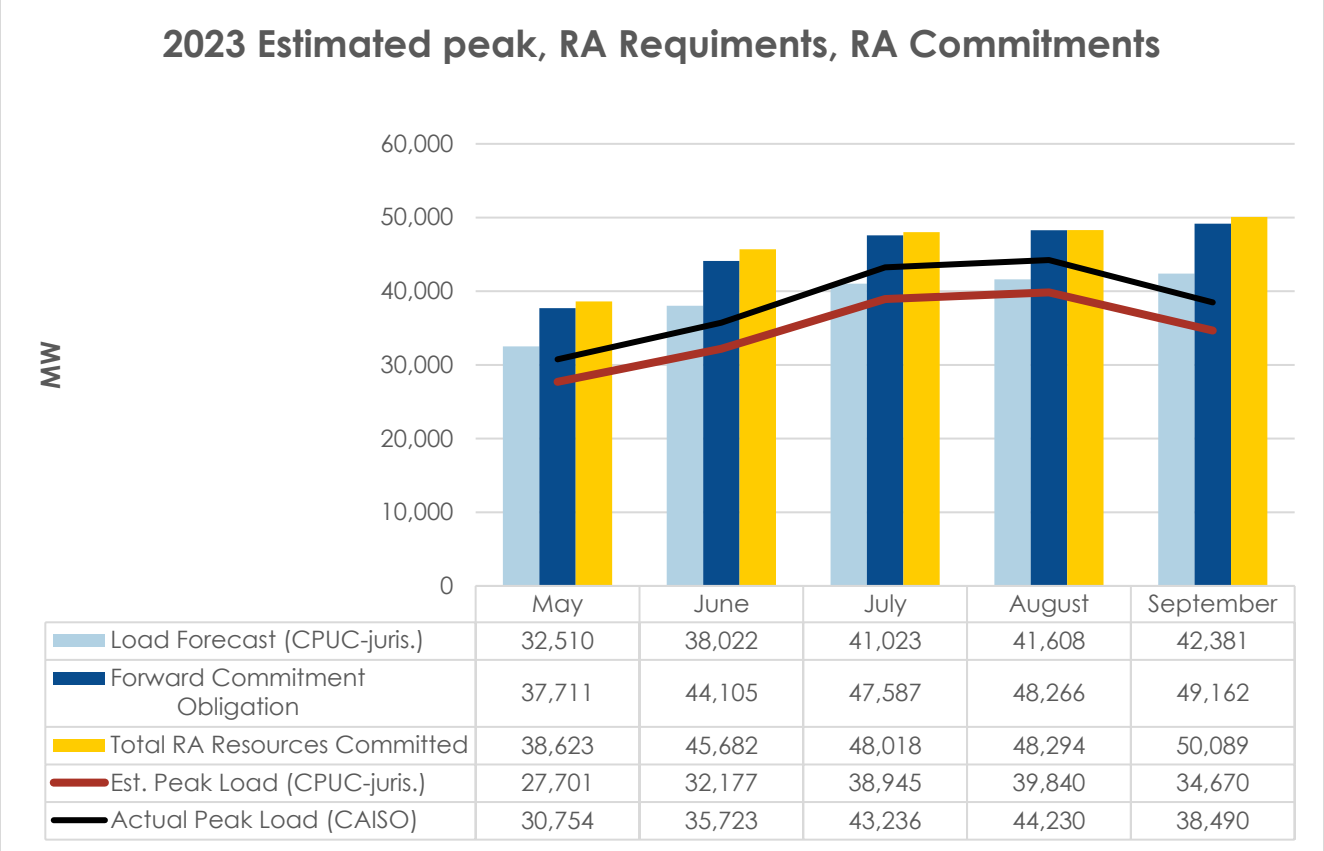
Figure 2 compares the 2023 total load forecast, procurement obligation (forecast plus PRM), and total committed RA capacity for CPUC-jurisdictional LSEs across the summer months. The yellow bars represent monthly committed RA capacity, while the red line indicates the estimated actual monthly peak load for CPUC-jurisdictional LSEs. The black line shows the actual monthly CAISO-wide system peak as a reference.

The actual CPUC-jurisdictional peak load is estimated using each the aggregate CPUC LSE coincident peak demand forecast as a proportion of the CAISO system coincident peak demand forecast. The difference between total RA capacity committed (yellow bars) and the collective forward obligation (dark blue bars) reflects the excess capacity committed to meet monthly RA obligations. The actual monthly CAISO jurisdictional peak (black line) includes load served by CPUC and non-CPUC-jurisdictional LSEs. This line is shown as reference because it was used in estimating the CPUCs portion of the actual load. It should not be used to when comparing against the yellow and blue bars as the yellow and blue bars do not include non-CPUC jurisdictional LSE data.

[22] This peak is the average used over the hour. The technical peak minute is recorded by CAISO as 52,061 MW at 16:57. When used in this report, the peak will refer to the peak hour measurement.

[23] https://www.caiso.com/documents/summermarketperformancereportforaugust2023.pdf

Figure 2. 2023 CPUC Month-Ahead Load Forecast, RA Requirements, Total RA Committed Resources, and Actual Peak Load For Summer Months



	May	June	July	August	September
Load Forecast (CPUC-juris.)	32,510	38,022	41,023	41,608	42,381
Forward Commitment Obligation	37,711	44,105	47,587	48,266	49,162
Total RA Resources Committed	38,623	45,682	48,018	48,294	50,089
Est. Peak Load (CPUC-juris.)	27,701	32,177	38,945	39,840	34,670
Actual Peak Load (CAISO)	30,754	35,723	43,236	44,230	38,490

Source: CPUC RA Filings, CEC load forecasts, and CAISO EMS data.

3.5 Local RA Program – CPUC-Jurisdictional LSEs

In D.19-02-022, the Commission adopted a 3 year forward local requirement for all LSEs. This included a 100% requirement in year one and two and a 50% requirement in year three. In D.20-06-002, the Commission established a Central Procurement Entity (CPE) and a hybrid central procurement framework in PG&E's and SCE's local distribution service areas. This framework was implemented beginning in 2021. While LSEs remained responsible for procuring 100% of their Local RA obligations through 2022, the CPEs assumed full procurement responsibility of the multi-year forward showing beginning with the 2023 RA compliance year. LSEs in SDG&E's service territory, however, maintained responsibility for their full three-year Local RA obligations.

Local RA requirements are developed through the CAISO's annual Local Capacity Technical Analysis, which identifies the capacity required in each Local area to meet energy needs using a 1-in-10 weather year and N-1-1 contingencies.[24] The results of the analysis are adopted in the annual June time frame CPUC RA decision and allocated to each LSE based on their load ratio in each TAC area during the month with the highest forecast peak load.

In D.22-06-050, the Commission adopted the 2023 Local RA obligations for the ten Locally constrained areas: Big Creek/Ventura, LA Basin, San Diego-Imperial Valley (IV), Greater Bay Area, Humboldt, North Coast/North Bay, Sierra, Stockton, Fresno, and Kern.

3.5.1 Year-Ahead Local RA Procurement

Table 5 summarizes the 2023 Local RA requirements and Year-Ahead procurement by CPUC-jurisdictional LSEs, including physical capacity procured by or on behalf of individual LSEs, CAM and RMR capacity, and Local DR capacity.

Table 5. Local RA Procurement in 2023, CPUC-Jurisdictional LSEs

Local Areas in 2023	Total LCR	CPUC-Jurisdictional Local RAR	Minimum Physical Resources per Month	SCE CPE	PGE CPE	Local RMR & CAM Credit	Local DR	Minimum Procurement/ Local RAR
LA Basin	7,529	6,781	829	6,988		1,806	639	151.3%
Big Creek/Ventura	2,240	2,017	138	2,123		247	115	130.0%
San Diego-IV	3,332	3,333	3,789	-		1,050	14	145.6%
Greater Bay Area	7,312	6,461	342	-	3,462	110	67	61.6%
Fresno	1,870	1,681	135	-	2,363	-	20	149.7%
Sierra	1,150	990	48	-	631	49	13	74.9%
Stockton	579	521	18	-	399	-	12	82.4%
Kern	439	395	58	-	186	-	58	76.5%
Humboldt	141	127	0	-	178	-	0	140.8%
NCNB	857	771	5	-	75	-	5	11.1%

[24] Local Capacity Requirement (LCR) studies and materials for 2023 and previous years are posted at California ISO - Reliability Requirements (caiso.com).

Totals	25,449	23,078	5,363	3,262	944	23.2%

Source: 2023 Year Ah

3.5.2 Local and Flexible RA True-Ups

The Local RA true-up mechanism, adopted in D.10-03-022 and later revised in D.14-06-050, continues to apply to all LSEs. This process accounts for load migration that occurs after the initial Year-Ahead allocation of Local and Flexible RA requirements. LSEs submit updated load forecasts for July through December, which are reviewed by the CEC to determine revised load ratios for those months. The CPUC then uses the updated August load shares to reallocate Local and Flexible RA obligations.

In the 2023 RA compliance cycle, LSEs submitted revised June – December forecasts on March 17, 2023. After review, the CEC revised September load shares, which the CPUC used to recalculate Local and Flexible RA obligations. These revised allocations were issued to LSEs on April 9, 2023, and were reflected in monthly filings from July to December. LSEs in the PG&E and SCE TAC area no longer received a local true-up. Only LSEs in SDG&E's TAC area do. LSEs were instructed to incorporate these incremental Local and Flexible allocations into their July to December RA Month-Ahead compliance filings. Through its review, Energy Division staff verified that each LSE met its reallocated Local and Flexible requirement for those months.

3.6 Flexible RA Program – CPUC-Jurisdictional LSEs

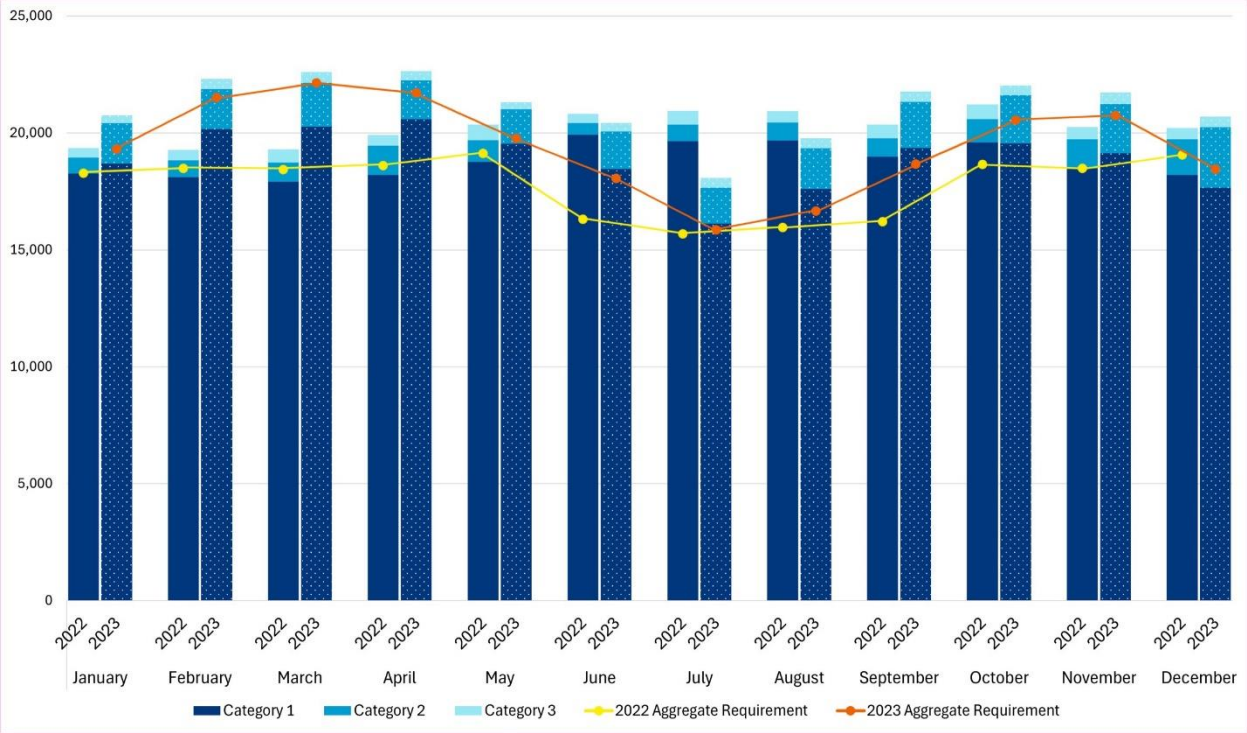
The CPUC adopted a Flexible RA requirement for LSEs beginning with the 2015 compliance year. LSEs must demonstrate that they have procured 90% of their monthly Flexible capacity requirements in the Year-Ahead process and 100% in the Month-Ahead process.[25] Flexible capacity needs are developed through the CAISO's annual Flexible Capacity Study and are defined as the quantity of economically dispatched resources needed by the CAISO to manage grid reliability during the largest three-hour

[25] D.13-06-024, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M070/K423/70423172.PDF; D.14-06-050, available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M097/K619/97619935.PDF.

continuous ramp in each month. Flexible resources must be able to ramp up or sustain output for 3 hours.

Figure 3 shows the monthly Flexible capacity requirements and the Flexible capacity shown on Month-Ahead RA plans by category by CPUC-jurisdictional LSEs for each month of 2022 and 2023. LSE procurement of Flexible capacity more closely followed the monthly requirements in 2023.

Figure 3. Comparison of 2022 and 2023 Flexible RA Procurement by Category, CPUC-Jurisdictional LSEs



Source: 2023 RA filings.

4 RESOURCE ADEQUACY PROCUREMENT, COMMITMENT, AND DISPATCH

The RA program requires LSEs to enter into forward-commitment capacity contracts with generating facilities. Only contracts that carry a "must-offer obligation" (MOO) are eligible to meet this RA obligation. The MOO requires resource owners to submit self-schedules or bids into the CAISO market, thereby making these resources available for

dispatch. In other words, the MOO commits these RA resources to participation in CAISO market mechanisms. Bilateral RA contract pricing is discussed in Section 4.1.

Under the CAISO market rules in 2023, the CAISO utilized these committed resources through its Day-Ahead market, Real-Time market, and Residual Unit Commitment (RUC) process. The CAISO also relies on out-of-market commitments – such as Exceptional Dispatch (ExD), CPM, and RMR contracts – to address reliability needs not met through market mechanisms. Recent RMR and CPM designations are described in Sections 4.2 and 4.3.

Since 2007, the CPUC has authorized the IOUs to procure new generation resources when needed for grid reliability. The CAM allows the net costs of these resources to be recovered from all benefiting customers in the IOU's TAC area. Since 2015, the RA capacity associated with CAM resources has been allocated as an increase to the IOUs' RA requirements and a credit towards non-IOU LSEs' RA requirements, with the IOUs showing the resources in their RA filings. These CAM resources carry the same must-offer obligation as all other RA resources. Certain other resource types that have been centrally procured by the IOUs – such as Combined Heat and Power (CHP) and DRAM resources – are similarly allocated. Current CAM resources are summarized in Section 4.4. In 2023, there is also CPE CAM that the CPEs procure and the system and flexible credits of those procured resources are allocated to all CPUC-jurisdictional LSEs only as credits, unlike other CAM resources, which is allocated as a debit and credit.

4.1 Resource Adequacy Contract Price Analysis

Energy Division issued routine price data requests to all CPUC-jurisdictional LSEs, seeking monthly RA contract prices paid by (or received) for every RA-only capacity contract executed in 2022 and 2023. This data was collected to support both the calculation of the Power Charge Indifference Adjustment (PCIA) RA adder and the RA price analysis presented here.

The data requests include solely RA-only contracts. Further it excludes energy-only (EO) contracts, contracts for deliverability rights, or other contracts not limited solely to RA-only capacity. Since RA compliance is a monthly framework and RA prices can vary by month, the data request required specific monthly pricing information from each contract. Contracts whose prices are null or less than $0.1 are removed from the calculations. All reported prices are reported in nominal dollars per kW-month.

Energy Division received responses from all LSEs. Unless otherwise noted, the analysis in this section is limited to contracts executed in 2022 through 2023 for delivery in 2023.[26] An exception is Table 6, which includes contracts executed in 2022 through Q3 of 2024 for deliveries spanning 2023—2025. This broader window affects prices for contracts delivered in 2024-2025 but does not affect those in 2023 as contracts executed in 2024 cannot be delivered in 2023. The overall MW of Contracted Capacity, the weighted average, mean, and 85th percentile prices differ in Tables 6-11 due to different types of contracts being excluded, which are described for each table.

4.1.1 System Capacity Prices

Table 6 provides a summary of System RA capacity prices for delivery in the 2023—2025 compliance years, based on contracts executed from 2022 through Q3 of 2024.

Table 6. RA System Capacity Prices in 2022-2024

	2023	2024	2025
Contracted Capacity (MW)	136,431	216,309	200,937
Weighted Average Price ($/kW-month)	$11.10	$14.51	$11.87
Average Price ($/kW-month)	$11.78	$17.31	$14.60
85% of MW at or below ($/kW-month)	$20.00	$30.00	$25.00

Source: 2022-2024 price data submitted by LSEs.

System capacity includes both resources that count solely toward System RA obligations (or toward both System and Flexible RA) and resources located in Local capacity areas that may also meet Local RA requirements. System capacity also includes specified imports but does not include unspecified imports.

Table 7 presents aggregated RA capacity prices for all reported contracts executed in 2022 through 2023 for deliveries in 2023, categorized by System and Local capacity, and further broken down by zonal area – north or south of Path 26 (NP-26 and SP-26, respectively). Resources' Local area and Path 26 zone were determined using the 2023

26 This is the same data request that supports the calculation of Market Price Benchmarks (MPB) for the Price Charge Indifference Adjustment (PCIA). The numbers in this report are different because the calculation parameters are different, not because the underlying data is different.

Net Qualifying Capacity (NQC) list.[27] Resources whose Local area is unknown are omitted.

After removing resources that cannot be categorized, the data set represents 134,680 MW-months of capacity under contract. Of that capacity:

- 52.2% is located in the NP-26 zone
- 46.4% is located in SP-26, and
- Just over 3.5% is comprised of imports, both specified and unspecified.

Having removed specified and unspecified imports, CAISO capacity breakdown is as follows:

- 51.8% is located in Local capacity areas, and
- 48.2% is located in the CAISO System area.

The weighted average price for all RA capacity in the data set is $11.34/kW-month. Prices were slightly higher in SP-26 at $11.24/kW-month, compared to the NP-26 weighted average price of $11.19/kW-month.

Table 7. Aggregated RA Contract Prices, 2023

	ALL RA				Local RA			CAISO System RA		
	Total	NP-26	SP-26	Import	Subtotal	NP-26	SP-26	Subtotal	NP-26	SP-26
Contracted Capacity (MW)	137,705	70,313	62,544	4,848	68,774	33,095	35,679	64,082	37,218	26,864
Percentage of Total Capacity in Data Set	100.00%	52.2%	46.4%	3.52%	51.1%	24.6%	26.5%	47.6%	27.6%	19.9%
Number of Monthly Values	5,663	2,565	2,849	250	2,966	1,382	1,584	2,546	1,183	1,265
Weighted Average Price ($/kW-month)	$11.34	$11.19	$11.24	$15.65	$11.21	$10.88	$11.51	$11.22	$11.46	$10.89
Average Price ($/kW-month)	$11.93	$12.85	$11.03	$13.01	$11.84	$12.78	$11.02	$11.95	$12.94	$11.03
85% of MW at or below ($/kW-month)	$20.00	$21.85	$16.00	$19.00	$20.00	$21.00	$16.00	$20.00	$23.00	$16.60

Source: 2022 and 2023 price data submitted by LSEs.

Table 8 presents monthly System RA capacity prices for CAISO resources,

[27] The 2023 Net Qualifying Capacity list can be found at Resource Adequacy Compliance Materials (ca.gov)

disaggregated by Path 26 zone (NP-26 and SP-26). For each, the share of the total dataset, weighted average, average, and 85th percentile prices are included in nominal dollars per kW-month. For this table, all imports (both specified and unspecified) and resources whose Local area is unknown are omitted.

Table 8. RA Capacity Prices by Month and Path 26 Zone, 2023

	Path 26 Zone	Contracted Capacity (MW)	Percentage of Total Capacity in Data Set	Weighted Average Price ($/kW-month)	Average Price ($/kW-month)	85th Percentile ($/kW-month)
Jan	North	4,410	3.32%	$6.08	$6.29	$8.64
	South	3,170	2.39%	$5.06	$5.86	$8.00
	Total	7,580	5.71%	$5.66	$6.07	$8.40
Feb	North	4,647	3.50%	$6.13	$6.45	$10.61
	South	3,595	2.71%	$5.06	$5.84	$8.00
	Total	8,242	6.20%	$5.66	$6.14	$8.50
Mar	North	6,321	4.76%	$5.63	$6.12	$8.49
	South	5,775	4.35%	$5.08	$5.68	$7.65
	Total	12,095	9.10%	$5.36	$5.89	$8.00
Apr	North	5,521	4.16%	$6.27	$6.59	$10.34
	South	5,598	4.21%	$5.41	$6.07	$7.80
	Total	11,119	8.37%	$5.84	$6.31	$8.33
May	North	6,649	5.00%	$7.50	$8.20	$12.55
	South	4,423	3.33%	$6.56	$7.02	$10.04
	Total	11,072	8.33%	$7.13	$7.63	$10.75
Jun	North	6,030	4.54%	$11.36	$13.05	$23.50
	South	4,521	3.40%	$10.06	$10.71	$19.25
	Total	10,551	7.94%	$10.80	$11.85	$22.00
Jul	North	5,997	4.51%	$15.57	$18.18	$32.00
	South	4,571	3.44%	$19.01	$15.98	$30.50
	Total	10,569	7.95%	$17.05	$17.08	$32.00
Aug	North	6,690	5.04%	$20.59	$23.76	$42.88
	South	6,535	4.92%	$22.29	$20.14	$39.75
	Total	13,225	9.95%	$21.43	$21.87	$40.74
Sep	North	6,870	5.17%	$22.57	$27.21	$48.50
	South	6,683	5.03%	$25.61	$23.63	$45.00
	Total	13,553	10.20%	$24.07	$25.37	$47.00
Oct	North	6,153	4.63%	$12.15	$12.58	$19.50

	South	5,215	3.93%	$10.45	$11.07	$16.00
	Total	11,368	8.56%	$11.37	$11.78	$17.50
Nov	**North**	5,878	4.42%	$6.96	$7.08	$10.92
	South	6,457	4.86%	$6.09	$6.58	$10.75
	Total	12,334	9.28%	$6.51	$6.79	$10.75
Dec	**North**	5,149	3.88%	$7.93	$7.84	$11.46
	South	6,000	4.52%	$6.21	$7.00	$11.20
	Total	11,150	8.39%	$7.01	$7.34	$11.37
Total	**North**	70,313	52.92%	$11.19	$12.85	$21.85
	South	62,544	47.08%	$11.24	$11.03	$16.00
	Total	132,857	100%	$11.21	$11.89	$20.00

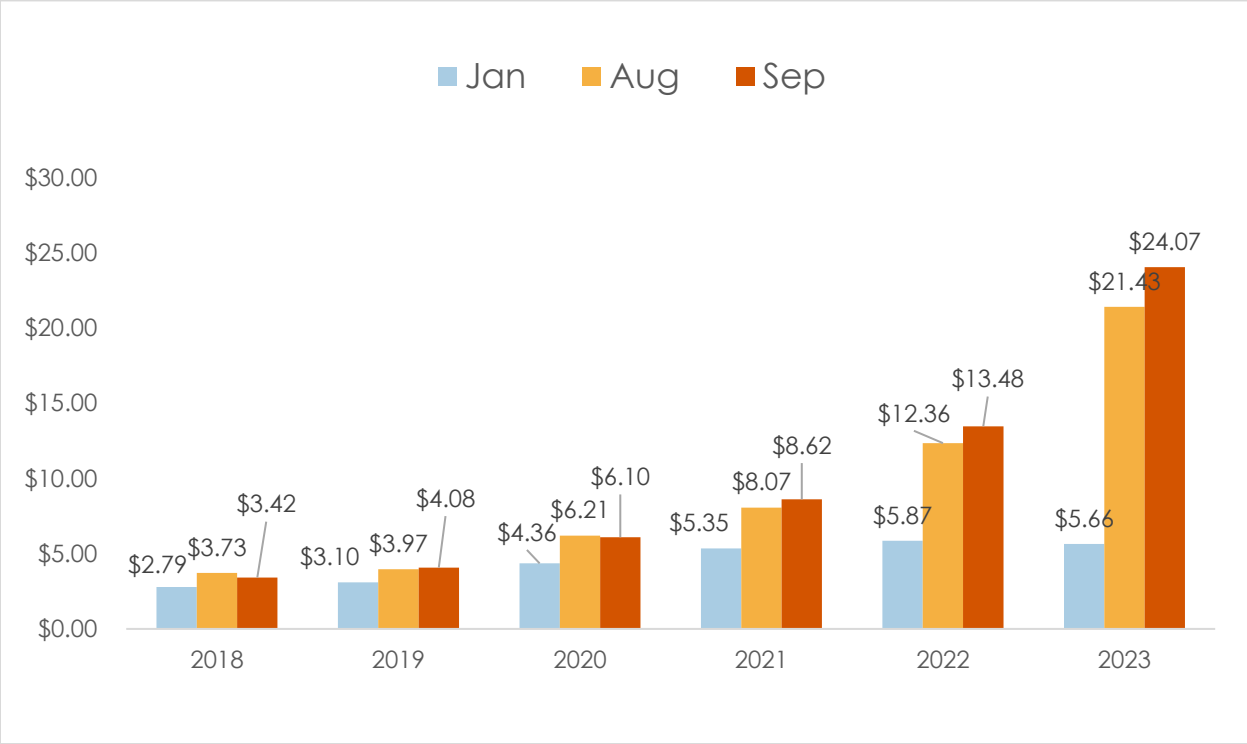
Source: 2022 and 2023 price data submitted by LSEs.

Figure 4 shows the monthly weighted average price of System RA for January, August, and September, from 2018 through 2023. Prices have consistently increased year-over-year, with the rate of increase accelerating in recent years. Until 2021, the weighted average price was highest in August; however, since 2021, September prices have consistently been the highest. In 2023, the weighted average price for September reached $24.07, which represents a 604% increase over the September 2018 weighted average of $3.42 and an approximate 79% increase over the 2022 September price of $13.48/kW-month. August prices rose to $21.43/kW-month in 2023, up 474% from 2018 and nearly 73% from $12.36/kW-month in 2022. January prices actually decreased to $5.66/kW-month, which was a 103% rise from 2018 and a 4% decrease from the 2022 price of $5.87/kW-month.

Several factors likely contributed to these sustained and accelerating price increases. First, increased load growth across California has resulted in higher RA obligations. The September 2023 peak load forecast was 3.9% higher than the 2022 forecast (Table 1, Section 3.2), contributing to increased procurement volumes across the system. Additionally, D.22-06-050 raised the PRM from 15% to 16%, incrementally increasing procurement requirements for all LSEs in 2023.

On the supply side, the market has continued to tighten. This tightening reflects several factors: the retirement of older gas plants, de-rate of QC values, limited availability of new fully dispatchable resources, and capacity counting restrictions on newer hybrid or storage-backed renewable resources under the MCC bucket framework. These conditions combined are likely contributing to higher procurement costs throughout 2023.

Figure 4: Weighted Average Price of System RA ($/kW-month), January, August and September 2018- 2023



Source: 2018-2023 price data submitted by LSEs.

4.1.2 Local Capacity Prices

Table 9 reports capacity prices by Local capacity area for 2023.[28] For comparison, prices for CAISO System capacity located outside of designated Local areas are also included. Both specified and unspecified imports are included in the Import category.[29] As in prior years, the majority of reported Local capacity under contracted was located in the

[28] The Humboldt Local Area is omitted due to confidentiality concerns

29 There was no Import category in the 2022 RA Report.

Bay Area and LA Basin Local Areas, which together accounted for 27% of total contracted capacity in the dataset. The weighted average price in the Bay Area is $11.45/kW-month, slightly above the CAISO System-wide average of $11.11/kW-month, while the LA Basin price of $11.00/kW-month is just below the CAISO System average.

Among Local areas, Kern ($8.26/kW-month) has the lowest weighted average prices, while Stockton ($14.99/kW-month) reflected the highest. Notably, the Kern local area prices actually decreased from its 2022 price of $8.50. Big Creek-Ventura saw only a slight year-over-year increase of 12.6%. On the other hand, San Diego saw RA prices increase 98% from 2022 ($7.14/kW-month) to 2023 ($14.15/kW-month), and Stockton saw RA prices increase 81% from 2022 ($8.27) to 2023 ($14.99).

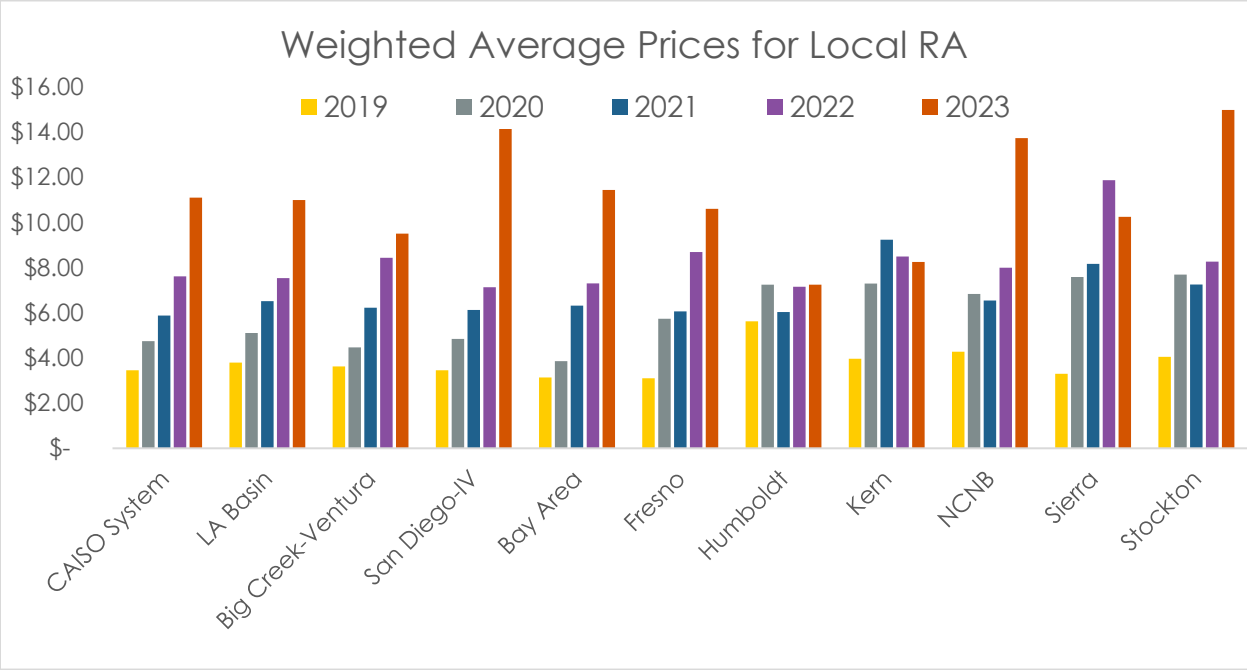
Table 9. Capacity Prices by Local Area, 2023

	Contracted Capacity (MW)	Percentage of Total Capacity in Data Set	Weighted Average Price ($/kW-month)	Average Price ($/kW-month)	85% of MW at or below ($/kW-month)
Stockton	568	0%	$14.99	$14.16	$26.44
Kern	3,842	3%	$8.26	$9.81	$12.00
Sierra	7,091	5%	$10.26	$12.47	$19.73
NCNB	1,079	1%	$13.75	$20.19	$32.00
Fresno	2,932	2%	$10.61	$11.73	$16.00
Big Creek-Ventura	7,914	6%	$9.51	$13.07	$23.50
San Diego-IV	9,528	7%	$14.15	$10.44	$10.50
LA Basin	18,237	14%	$11.00	$10.66	$15.00
Bay Area	17,566	13%	$11.45	$12.87	$21.00
Import	4,848	3%	$15.65	$13.01	$19.00
CAISO System	65,834	49%	$11.11	$11.93	$20.00
Grand Total	139,456	100%	$11.28	$11.92	$20.00

Source: 2022 and 2023 price data submitted by LSEs.

Figure 5 tracks weighted average RA prices from 2019 to 2023 for each of the ten Local areas and the CAISO System. Local areas with the largest RA obligations – LA Basin, Bay Area, San Diego-IV, and Big Creek-Ventura – have generally followed trends in CAISO system prices, although some divergence is apparent in 2023.

Figure 5. Weighted Average Price of Local RA ($/kW-month), 2019-2023



Source: 2019-2023 price data submitted by LSEs and presented in past RA Reports

Table 10 shows weighted average and 85th percentile prices by month for each Local area and for CAISO System resources not sited in a Local area. It also shows monthly Import prices.

Table 10. Local RA Capacity Prices by Month, 2023

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CAISO System	**Weighted Average**	$5.01	$5.02	$4.92	$5.36	$6.78	$10.78	$19.08	$22.93	$26.18	$11.05	$5.95	$6.63
	85th Percentile	$8.00	$8.00	$7.62	$8.00	$10.75	$20.00	$32.00	$46.10	$48.50	$16.68	$10.98	$12.08
LA Basin	**Weighted Average**	$6.14	$6.31	$5.49	$6.08	$6.92	$7.97	$9.84	$18.82	$23.47	$10.41	$6.56	$6.78
	85th Percentile	$7.70	$7.70	$7.33	$7.24	$9.82	$12.00	$23.00	$32.50	$45.00	$16.00	$11.48	$11.50
Big Creek-Ventura	**Weighted Average**	$5.31	$5.05	$5.04	$5.05	$8.37	$10.55	$13.40	$17.54	$20.83	$13.09	$6.56	$6.55
	85th Percentile	$10.50	$9.64	$8.67	$6.87	$10.50	$35.00	$35.00	$35.00	$45.00	$20.00	$12.20	$12.20

San Diego-IV	**Weighted Average**	$6.33	$6.34	$5.78	$5.69	$6.44	$9.40	$19.40	$27.82	$32.40	$7.87	$5.83	$5.14
	85th Percentile	$7.79	$7.77	$7.65	$7.35	$7.77	$12.00	$30.00	$45.64	$55.00	$8.75	$7.49	$7.53
Bay Area	**Weighted Average**	$6.59	$6.13	$6.32	$7.24	$7.42	$11.55	$14.04	$20.83	$18.57	$13.12	$8.23	$9.38
	85th Percentile	$8.00	$8.00	$8.00	$9.00	$10.54	$23.63	$35.00	$38.40	$40.00	$17.50	$10.75	$10.85
Fresno	**Weighted Average**	$7.46	$7.38	$6.15	$9.20	$10.44	$13.69	$12.46	$13.34	$15.08	$12.30	$6.57	$8.45
	85th Percentile	$11.45	$11.45	$11.35	$12.94	$13.30	$16.36	$20.00	$32.00	$41.75	$20.00	$11.35	$11.45
Kern	**Weighted Average**	$6.41	$6.93	$6.55	$6.54	$7.26	$8.94	$11.27	$9.90	$12.24	$8.61	$6.77	$6.97
	85th Percentile	$10.56	$11.37	$10.56	$9.59	$12.00	$21.50	$21.81	$20.02	$20.48	$20.01	$12.00	$12.00
NCNB	**Weighted Average**	$4.00	$5.73	$5.09	$5.88	$23.50	$23.85	$27.47	$39.09	$24.69	$15.76	$5.21	$3.99
	85th Percentile	$5.73	$5.73	$6.00	$6.00	$23.50	$23.50	$32.00	$65.60	$60.00	$23.50	$5.88	$5.80
Sierra	**Weighted Average**	$7.02	$7.58	$6.74	$7.16	$7.50	$11.82	$14.26	$17.25	$17.85	$11.96	$6.50	$7.45
	85th Percentile	$10.05	$10.95	$10.69	$10.65	$10.69	$21.05	$32.00	$52.93	$58.20	$20.00	$10.65	$10.65
Stockton	**Weighted Average**	$7.17	$7.72	$8.03	$8.22	$7.17	$12.47	$18.85	$27.28	$33.20	$17.11	$7.84	$7.78
	85th Percentile	$10.88	$9.56	$10.06	$11.21	$10.85	$14.33	$25.70	$35.20	$42.00	$18.88	$10.75	$10.75
Imports	**Weighted Average**	$5.90	$5.88	$5.26	$5.64	$12.23	$12.17	$15.01	$24.34	$23.72	$15.28	$5.80	$5.72
	85th Percentile	$5.90	$5.90	$5.90	$5.90	$17.50	$17.50	$20.16	$20.30	$42.50	$18.02	$6.25	$6.25

Source: 2022 and 2023 price data submitted by LSEs

4.1.3 Flexible Capacity Prices

Table 11 summarized RA capacity prices for Flexible vs. Non-Flexible System capacity, excluding imports. Flexible capacity must meet specific ramping and dispatchability requirements and represents a subset of System resources. In 2023, the weighted system

average price for Flexible capacity was $7.80/kW-month, considerably lower than the $14.33/kW-month average for non-Flexible System capacity as well as the $11.21/kW-month average for Local capacity.[30] Between 2022 and 2023, the flexible capacity price increased by 18% and the non-Flexible System capacity increased by 79.1%. Table 11 has changed since 2022 in that we added a third column of all Local Capacity RA contracts, but the Flexible Capacity and System Capacity remain calculated in a similar way as they were previously, except with both specified and unspecified Imports included.[31]

Table 11. Flexible vs. Non-Flexible CAISO System Prices Including Imports, 2023

	Flexible Capacity	System Capacity (including Imports)	Local Capacity
Contracted Capacity (MW)	31,484	39,197	68,774
Percentage of Total Capacity in Data Set	22.6%	28.1%	49.3%
Weighted Average Price ($/kW-month)	$7.80	$14.33	$11.21
Average Price ($/kW-month)	$9.83	$12.98	$11.84
85% of MW at or below ($/kW-month)	$12.00	$20.94	$20.00

Source: 2023 price data submitted by LSEs.

30 For the 2023 RA Report, an adjustment was made to the method of counting Flexible capacity. Flexible capacity at times is provided in data requests as 2x System capacity when the resources are batteries, as they count when they charge and when they discharge. We now calculate these resources by first qualifying if they are Flexible or System and then counting the System capacity alone. Under the old method, the weighted average price would be $7.95 instead of $7.80.

31 The NQC list has a flag for the various Local areas and the data request has a section where LSEs fill in the Flexible capacity they procure. If a resource has Flexible capacity, but is in a Local area, it is counted as a Local resource.

4.2 CAISO Out of Market Procurement – RMR Designations

The CAISO's Reliability Must Run (RMR) and Capacity Procurement Mechanism (CPM) capabilities are the primary mechanisms CAISO can use to backstop load-serving entity (LSE) procurement. Under its RMR authority, CAISO has the right to designate a resource as an RMR unit in order to support reliable system operations. Accepting an RMR designation is mandatory, and the owner of the RMR unit may terminate the RMR contract only under extremely narrow circumstances. As stated in section 41.3 of the CAISO tariff, the CAISO does not use its RMR authority to address RA deficiencies. The intent of the CAISO's RMR authority is to designate resources for RMR service as a measure of last resort to retain resources for reliability that would otherwise seek to retire or mothball. RMR designations are contract year or remainder of contract year designations to address longer-term reliability needs. RMR designations do not address procurement or contracting issues. The CAISO will designate for RMR service those resources that: (1) submitted a notice to retire or mothball; (2) are needed to meet certain needs identified by reliability studies; and (3) have not been procured as RA or were unlikely to be procured as RA.

The CAISO may designate certain generating units as Reliability Must-Run (RMR) resources when they are deemed necessary to maintain grid reliability but are not otherwise retained through market mechanisms. RMR designations can apply to either existing contracts or new contracts triggered by emerging reliability needs. Existing RMR contracts must be re-designated by October 1 of each year and approved by the CAISO Board of Governors for inclusion in the following compliance year. New RMR contracts, by contrast, are more flexible and may be initiated at any point during the year.

RMR-designated resources can be dispatched by the CAISO to maintain reliability and are paid for by customers within the applicable transmission area or by all customers, depending on the underlying reason prompting the designation. Pursuant to D.06-06-064, the CPUC applies a capacity credit for RMR-designated resources when calculating RA compliance obligations.

In line with the CPUC's stated policy preference to minimize reliance on out-of-market procurement, Local RA requirements were introduced beginning with the 2007

compliance year to supplant the need for RMR contracting. [32] This shift resulted in significant decline in the number of RMR designations through 2011, when only one RMR contract remained active.[33]

However, RMR designations began to increase again in 2017. For the 2018 compliance year, the CAISO designated four resources under RMR Condition 2 contracts. Calpine Corporation's Feather River Energy Center (45 MW) and Yuba City Energy Center (46 MW) received Condition 2 RMR contracts for Other PG&E Areas and Metcalf Energy Center (570 MW) received a Condition 2 RMR contract for the Bay Area. Dynegy Oakland's Units 1, 2, and 3 were also designated to ensure Local reliability in Oakland, California.

In 2018, for the 2019 compliance year, the CAISO extended RMR contracts for three generating facilities: Calpine Corporation's Feather River Energy Center (45 MW), Yuba City Energy Center (46 MW), and Dynegy Oakland, LLC's Units 1, 2, and 3.

In 2021, the CAISO extended and signed five RMR contracts for the 2022 compliance year: Green Leaf II Cogen (49.2 MW), CSU Channel Islands (27.5 MW), Midway Sunset Cogen (262.10 MW in August), and Dynegy Oakland, LLC's Units 1 and 3 (110 MW).

For the 2023 compliance year, the CAISO maintained three RMR contracts with generating facilities, including Green Leaf II Cogen (49.2 MW) and Dynegy Oakland, LLC's Units 1 and 3 (110 MW). Table 12 displays the plants with RMR Designations for 2023.

Table 12. CAISO RMR Designations for 2023

Unit	MW
Greenleaf II Cogen	49.2
Oakland, Unit 1	55
Oakland, Unit 3	55

[32] D.06-06-064, Section 3.3.7.1., Available at: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/57644.DOC.

[33] Dynegy Oakland LLC's Units 1, 2 and 3 (165 MW).

4.3 CAISO Out of Market Procurement – CPM Designations

CAISO implemented the Capacity Procurement Mechanism (CPM) effective April 1, 2011, to procure capacity to maintain grid reliability. CAISO can use its CPM authority to address specific needs defined by the following six CPM designation types:

1. Insufficient Local capacity area resources in an annual or monthly RA plan
2. Collective deficiency in Local capacity area resources
3. Insufficient RA resources in an LSE's annual or monthly RA plan
4. A CPM significant event
5. A reliability or operational need for an exceptional dispatch CPM
6. A cumulative deficiency in the total Flexible RA capacity included in the annual or monthly Flexible RA capacity plans, or in a Flexible capacity category in the monthly Flexible RA capacity plans[34]

Eligible capacity is limited to resources that are not already under contract to be an RA resource, are not under an RMR contract, and are not currently designated as CPM capacity. Eligible capacity must be capable of effectively resolving a procurement shortfall or a reliability concern.

For Exceptional Dispatch CPMs, CAISO may designate the greater of a resource's PMin (minimum operating level) or the capacity necessary to meet the reliability need (beyond what is already committed through committed RA capacity, capacity subject to an RMR contract, or has been subject to a self-schedule or market based commitment) per CAISO Tariff Section 43A.2.5. This capacity is identified through engineering assessment of the event.[35]

CAISO's CPM designations rely on capacity willingly offered by resource scheduling coordinators.

Since 2016, CPM pricing has been determined by an annual, monthly, and intra-monthly Competitive Solicitation Process (CSP). The CPM soft offer cap is based on a reference resource methodology defined in the CAISO tariff. Specifically, the levelized

[34] CAISO Tariff 43A.2- section-43a-capacity-procurement-mechanism-as-of-may-1-2025.pdf

[35] ISO Tariff Section 43.A.2.5.2.1, https://www.caiso.com/documents/section-43a-capacity-procurement-mechanism-as-of-may-1-2025.pdf

going-forward fixed costs of a mid-cost, 550 MW combined cycle plant with duct firing, plus a 20% premium. From 2016 to 2023, the price of the CPM soft offer cap was $6.31/kW-month.[36] However, a supplier may apply to FERC to justify a price higher than the soft offer cap prior to offering the resource into the competitive solicitation process or after receiving a capacity procurement mechanism designation by the CAISO.[37]

In 2023, CAISO launched the CPM Enhancements Initiative, [38] structured in two tracks:

- Track 1: Addresses CPM operational improvements to maximize use of uncontracted capacity in specific calendar months. The CAISO Board of Governors approved Track 1 enhancements in March 2023.
- Track 2: CAISO staff propose to increase the CPM soft offer cap from $6.31/kW-month to $7.34/kW-month, based on:
  1. $7.34/kW-month is a figure based on the CAISO tariff-defined methodology for deriving the soft offer cap, using updated CEC-provided combined cycle going-forward fixed costs;
  2. The CAISO tariff-defined methodology for deriving the CPM soft offer cap is still reasonable and relevant until a broader relook of the CAISO's RA processes can be completed; and
  3. The proposed increase to the soft offer cap accounts for recent inflation and is directionally appropriate, given the increase in bilateral capacity prices over recent years.

The CAISO Board of Governors approved the Track 2 proposals in September 2023. CAISO submitted a tariff amendment request to update the CPM soft offer cap to FERC on February 9, 2024.[39] The updated CPM soft offer cap is effective in the summer of 2024.

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36 As of June 2024, the CPM soft offer cap price is $7.34/kW-month.

[37].ISO Tariff Section 43A.4.1.1.1, Section43A-CapacityProcurementMechanism-asof-Aug15-2022.pdf (caiso.com)

[38] California ISO - Capacity procurement mechanism enhancements (caiso.com)

[39] CAISO Tariff Amendment to FERC, February 9, ,2024, Feb9-2024-TariffAmendment-CapacityProcurementMechanism-Track2-ER24-1225.pdf (caiso.com)

Table 13. CAISO CPM Designations for 2023

Resource ID	MW		Term (days)	Start Date	End Date	Est. Cap. Cost /kW-Month
ELCAJN_6_LM6K	48.10	CADEF	30	8/1/2023	8/31/2023	6.31
MRCHNT_2_PL1X3	82.25	CADEF	30	8/1/2023	8/31/2023	6.31
CHINO_2_PESBT1	10.00	CADEF	30	8/1/2023	8/31/2023	6.31
MARVEL_2_MARBT3	45.71	CADEF	30	8/1/2023	8/31/2023	6.31
SYCAMR_2_UNIT 3	70	Exceptional Dispatch (ED)	60	11/2/2023	1/1/2024	6.31

Source: CPM Designation posted by CAISO at California ISO - California ISO - Documents By Group (caiso.com)

4.4 IOU Procurement for System Reliability and Other Policy Goals

This subsection discusses the different types of procurement that IOUs have been directed to undertake on behalf of all LSEs, either by statute or through CPUC decisions.

4.4.1 System Reliability Resources

D.06-07-029 adopted a procurement process known as the Cost Allocation Mechanism, or CAM, which allows the CPUC to direct IOUs to procure new generation to support System reliability within an IOU's distribution service territory. Under CAM, all associated costs and benefits are allocated to all benefiting customers, including bundled utility customers, direct access customers, and customers of community choice aggregators (CCAs). The LSEs serving these customers are proportionally allocated the capacity in each service territory, which counts toward meeting LSEs' RA requirements. LSEs receiving CAM capacity pay only the net cost of the capacity, defined as the total cost of the power purchase contract price minus any energy revenues associated with the dispatch of the resource.

D.11-05-005 eliminated the IOUs' authority to elect whether to apply CAM to new generation resources. However, the decision did permit the use of CAM for utility-owned generation and allowed the CAM designation to extend for the full duration of the contract for the resource.

Table 14 provides the scheduling resource ID, CAM contract term, authorized IOU, and August NQC values for all 2023 CAM resources. The table includes all conventional generation resources currently subject to the CAM mechanism. Utility-owned generation (UOG) remains a CAM resource while the generator is operational and thus has no CAM end date.

Table 14. CAM Reliability Resources as of 2023

Decision or Resolution Authorizing Contract	Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
E-4949	VISTRA_5_DALBT1	6/1/2021	5/31/2041	PG&E	100.00
E-4949	VISTRA_5_DALBT2	6/1/2021	5/31/2041	PG&E	100.00
E-4949	VISTRA_5_DALBT3	6/1/2021	5/31/2041	PG&E	100.00
E-4949	ELKHRN_1_EESX3	10/1/2021	12/31/2050	PG&E	182.50
E-4804	CHINO_2_APEBT1	12/31/2016	12/30/2026	SCE	20.00
E-4804	SANTGO_2_MABBT1	10/1/2017	12/31/2026	SCE	2.00
D.09-03-031	BARRE_6_PEAKER	7/19/2007	UOG	SCE	49.00
D.09-03-031	CENTER_6_PEAKER	7/20/2007	UOG	SCE	47.30
D.09-03-031	ETIWND_6_GRPLND	7/17/2007	UOG	SCE	45.64
D.14-06-043	MNDALY_6_MCGRTH	8/1/2009	UOG	SCE	48.56
D.09-03-031	MIRLOM_6_PEAKER	7/19/2007	UOG	SCE	47.18
D.18-06-009	MIRLOM_2_MLBBTA	7/1/2017	6/30/2027	SCE	10.00
D.18-06-009	MIRLOM_2_MLBBTB	7/1/2017	6/30/2027	SCE	10.00
D.15-11-041	ALAMIT_2_PL1X3	6/1/2020	5/31/2040	SCE	674.70
D.15-11-041	HNTGBH_2_PL1X3	5/1/2020	4/30/2040	SCE	673.80
D.15-11-041	STANTN_2_STAGT1	7/1/2020	6/30/2040	SCE	49.00
D.15-11-041	STANTN_2_STAGT2	7/1/2020	6/30/2040	SCE	49.00
D.15-11-041	ALAMIT_7_ES1	1/1/2021	12/31/2040	SCE	100.00
A.19-04-016	SNCLRA_2_VESBT1	7/1/2021	3/31/2041	SCE	100.00
AL 4002-E	GOLETA_2_VALBT1	4/1/2021	11/30/2040	SCE	10.00
AL 4002-E	SNCLRA_2_SILBT1	6/1/2021	12/31/2040	SCE	11.00
D.13-03-029	ESCNDO_6_PL1X2	5/1/2014	12/31/2039	SDGE	48.71
D.14-02-016	PIOPIC_2_CTG1	6/1/2017	12/31/2037	SDGE	111.30
D.14-02-016	PIOPIC_2_CTG2	6/1/2017	12/31/2037	SDGE	112.70

D.14-02-016	PIOPIC_2_CTG3	6/1/2017	12/31/2037	SDGE	112.00
Res E-4798	ESCNDO_6_EB1BT1	03/06/2017	12/31/2099	SDGE	10.00
Res E-4798	ESCNDO_6_EB2BT2	03/06/2017	12/31/2099	SDGE	10.00
Res E-4798	ESCNDO_6_EB3BT3	03/06/2017	12/31/2099	SDGE	10.00
Res E-4798	ELCAJN_6_EB1BT1	02/21/2017	12/31/2099	SDGE	7.50
D.15-05-051	CARLS1_2_CARCT1	12/1/2018	9/30/2038	SDGE	422.00
D.15-05-051	CARLS2_1_CARCT1	12/1/2018	9/30/2038	SDGE	105.50
D.18-05-024	MRGT_6_TGEBT1	8/1/2021	12/31/2099	SDGE	30.00
D.18-05-024	FALBRK_6_FESBT1	11/1/2022	12/31/2099	SDGE	40

*NQC values are from August 2023. For resources that began after August 2023, the August 2023 NQC is provided. NQC values can change monthly and annually.

4.4.2 QF/CHP Resources

D.10-12-035[40] adopted a Settlement for Qualifying Facilities and Combined Heat and Power (QF/CHP Settlement). The Settlement established the CHP program, which requires IOUs to procure a minimum of 3,000 MWs of capacity over the program period and to reduce greenhouse gas (GHG) emissions consistent with the California Air Resources Board (CARB) Climate Change Scoping Plan. D.15-06-028 subsequently reduced the GHG emissions reductions target to 2.72 million metric tons.

The Settlement also established a cost allocation mechanism to be used to distribute the benefits and costs associated with meeting the CHP and GHG goals.[41] The adopted cost allocation mechanism was almost identical to the mechanism adopted in the Long-Term Procurement Plan (LTPP) for reliability in D.06-07-029. Under this mechanism, the net capacity costs of an approved CHP resource are allocated to all benefiting customers,

[40] https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/128624.PDF

[41] CHP Program Settlement Agreement Term Sheet 13.1.2.2 http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124875.PDF.

including bundled, ESP, and CCA customers. The RA benefits associated with the CHP contract are also allocated to all customers paying the net capacity costs.[42]

Table 15 below lists the CHP resources whose RA capacity was allocated as of 2023.

Table 15. CHP Resources Allocated for CAM as of 2023

Decision or Resolution Authorizing Contract	Scheduling Resource ID	CAM Start Date	CAM End Date	August NQC*	Authorized IOU
D. 10-12-035	CHARMN_2_PGONG1	9/1/2020	12/31/2026	19.87	SCE
E-4860	CHINO_6_CIMGEN	7/1/2018	3/11/2025	26.00	SCE
D.14-7-019	CHEVMN_2_UNITS	12/29/1987	8/31/2026	7.93	SCE
AL 4123-E	ELKHIL_2_PL1X3	1/1/2021	1/1/2024	100.00	SCE
Pending	FRITO_1_LAY	11/1/2019	10/31/2026	0.00	PG&E
D.10-12-035	GRZZLY_1_BERKLY	8/1/2017	7/31/2024	0.50	PG&E
E-5037	KERNRG_1_UNITS	10/1/2019	9/30/2026	0.62	PG&E
Res E-4799	SAMPSN_6_KELCO1	6/1/2017	6/2/2022	1.51	SDG&E
AL 3882-E	SNCLRA_6_PROCGN	1/1/2020	12/30/2026	12.74	SCE
E-4648	STOILS_1_UNITS	8/1/2014	7/31/2026	3.33	PG&E
E-5037	TANHIL_6_SOLART	12/1/2019	11/30/2026	10.82	PG&E

*NQC values are from August 2023. If the unit was not CHP CAM in August 2023, then the applicable August NQC from the year of retirement is shown. NQC values can change monthly and annually.

4.4.3 DR Resources

D.14-12-024 authorized pilot DRAM auctions as a means for IOUs to procure DR capacity from third party DR providers. Capacity procured through DRAM is allocated to all customers in a manner similar to CAM and CHP resources. Table 16 lists the DRAM capacity procured by the IOUs for 2023.

Table 16. DRAM Capacity Allocated for CAM for 2023

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*

[42] Section 13.1.2.2 of the QF settlement states:" In exchange for paying a share of the net costs of the CHP Program, the LSEs serving DA and CCA customers will receive a pro-rata share of the RA credits procured via the CHP Program."

Multiple	1/1/2023	12/31/2023	PG&E	83.00
Multiple	1/1/2023	12/31/2023	SCE	103.20
Multiple	1/1/2023	12/31/2023	SDG&E	23.80
Total				**210.00**

*NQC values can vary by month.

IOU event-based DR resources are market-integrated and also qualify as RA credit. The costs for most DR programs are allocated through the IOU delivery charge, meaning these programs are paid for by bundled customers, direct access customers, and customers of CCAs. Exceptions include SCE's Smart Energy Program and rate-based programs such as the Critical Peak Pricing (CPP) programs offered by SCE and PG&E.

The RA credit associated with DR is based on its QC value which is calculated using the CPUC-adopted Load Impact Protocols. On an annual basis the IOUs and third-party DR providers submit ex-ante load impact values for each market-integrated DR program on April 1st for the upcoming RA compliance year. Energy Division reviews and evaluates the ex-ante load impact values using the ex-post actual performance load impacts from the previous year and the programs' forecast assumptions. Once finalized, DR RA credit values are posted to the CPUC's RA compliance website and allocated to all LSEs for the applicable compliance year.

Table 17 and Figure 6 illustrate the amounts and types of procurement credit (DR, CAM, and RMR) that have been allocated since the beginning of the RA program. CPE credits are separate and are not included in the CAM numbers.

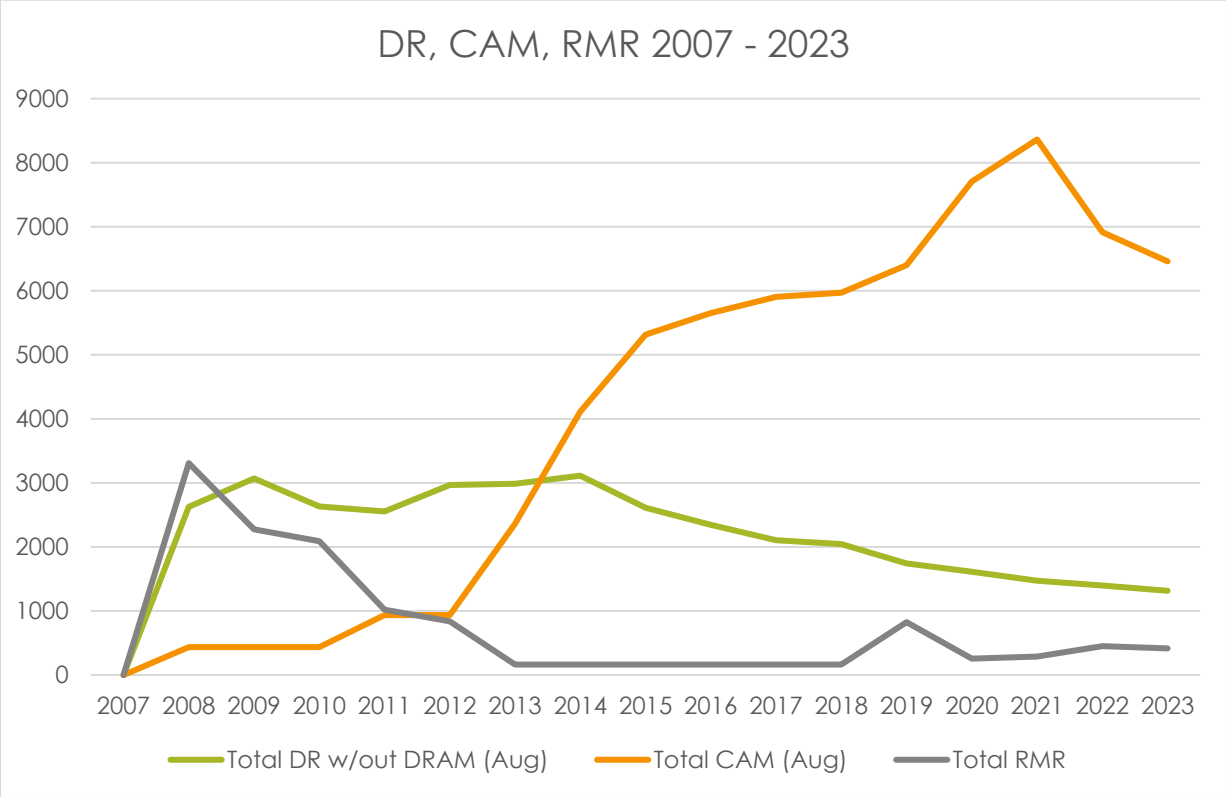
Table 17. DR, CAM, and RMR Allocations for August, 2007-2023 (MW)

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
DR	SCE		1,705	1,616	1,613	1,838	2,067	2,195	1583	1593	1480	1437	1215	1125	1031	977	1001	976
	PG&E		1018	912	846	888	744	783	933	689	565	566	488	448	424	402	301	285
	SDG&E		346	104	97	241	177	135	96	63	60	42	40	39	17	19	14	15
	Total DR w/out DRAM (Aug)	**2,628**	**3,069**	**2,632**	**2,556**	**2,967**	**2,988**	**3,113**	**2,613**	**2,345**	**2,105**	**2,045**	**1,743**	**1,612**	**1,472**	**1,397**	**1,316**	**1,276**
CAM	SCE	436	436	436	936	936	1,529	2,763	3,477	3,583	3,848	3,702	4,091	4,742	5,535	4,480	4,098	2,226
	PG&E						703	1,351	1,790	2,020	2,008	1,868	1,897	1,989	1,848	1,422	1,344	580
	SDG&E						130		49	49	49	399	413	975	980	1,012	1,018	1,052
	Total CAM (Aug)	**436**	**436**	**436**	**936**	**936**	**2,362**	**4,114**	**5,316**	**5,652**	**5,905**	**5,969**	**6,401**	**7,706**	**8,363**	**6,915**	**6,459**	**3,858**

RMR	SCE														76	28		
	PG&E	1,348	1,303	1,263	709	527	165	165	165	165	165	165	826	256	214	159	155	154
	SDG&E	1,961	973	828	311	311									0			
	System															264	262	
	Total RMR	**3,309**	**2,276**	**2,091**	**1,020**	**838**	**165**	**165**	**165**	**165**	**165**	**165**	**826**	**256**	**290**	**450**	**417**	**154**

Figure 6 reflects the decline in RMR units – except for a spike in 2018 – and the increase in CAM units through 2020, followed by declines in 2021, 2022, and increase in 2023 when including CPE CAM. 2023 CAM number does not include CPE CAM. Total CPE CAM credits from PG&E CPE and SCE CPE are 2,885.17 MW for August 2023. Adding CPM CAM would be 6,743 MW for 2023 CAM, which is an increase from 2022. DR RA credits have declined slightly since 2013.

Figure 6. DR, CAM, and RMR Allocations for August, 2007-2023 (MW)



In August 2023, the total amount of capacity procured through DR, CAM, and RMR was 5,288 MW, including CPE CAM is 8,173 MW, representing approximately 17% of the

total CPUC-jurisdictional LSE RA obligation 48,294 MW for that month. CAM procurement totaled 3,858 MW, including CPE CAM is 6,743 MW, which increased from 2022, while RMR procurement declined from 417 MW in 2022 to 154 MW in 2023.

5 NET QUALIFYING CAPACITY (NQC)

Qualifying Capacity (QC) represents the maximum capacity of a resource eligible to be counted toward meeting the CPUC's RA requirements, prior to any assessment of deliverability. The CPUC adopted QC counting conventions in D.10-06-036,[43] with updates to the methodologies adopted in subsequent decisions. QC values are determined based on the applicable resource type, using data sets and conventions largely outlined in the adopted QC Methodology Manual.[44]

The QC methodology varies by resource type:

- **Dispatchable resources:** QC is based on the most recent maximum capability (Pmax) test.
- **Non-dispatchable hydro and geothermal resources:** QC is based on historical production.
- **Combined Heat and Power (CHP) and Biomass resources** that can bid into the Day-Ahead market, but are not fully dispatchable, receive QC values based on the MW amount bid or self-scheduled into the Day-Ahead market.
- **Wind and solar resources:** QC is based on ELCC modeling.

The CPUC annually issues a subpoena to CAISO for settlement quality meter and bidding data, which is used to calculate QC values for non-dispatchable resources. In D.22-06-050 The Commission updated the ELCC values for Solar and Wind resources beginning with the 2023 RA compliance year[45].

[43] https://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/119856.PDF (QC manual adopted as Appendix B).

[44] Microsoft Word - Adopted QC Methodology Manual 2020 final.docx (ca.gov).

[45] D.22-06-050 at OP 10 - 488540633.PDF

Once the QC values are calculated by Energy Division Staff, the CAISO then conducts a deliverability assessment to determine the annual NQC value of each resource. If a resource's QC is greater than its deliverable capacity, the NQC is adjusted to reflect the deliverable capacity. The CAISO conducts deliverability assessments two to three times a year pursuant to the Large Generator Interconnection Procedures (LGIP) for both new and existing resources.

Following the deliverability assessment, the CAISO publishes a draft NQC list in mid to late August. Generators typically have a three-week period to file comments with the CAISO and CPUC regarding the proposed NQC values. After review comments and making any necessary adjustments, the CAISO and the CPUC release their final NQC lists. This NQC list includes each resource's Local Area, zonal area, and deliverable capacity.

5.1 New Resources and Retirements in 2023

Overall, in 2023, there was an increase in available capacity. A total of 2,929 MW of capacity (NQC) was brought online in 2023, while 866 MW of capacity was retired.

Table 18 lists the new facilities that came online in 2023, and Table 19 lists the retiring and mothballed facilities. Net dependable capacity – the amount of deliverable capacity as determined by the CAISO – is also listed for new facilities. Generators can come online as energy-only facilities with no NQC value or in phases, with the initial NQC value well below the planned capacity.

Solar and wind resources also have NQC values well below net dependable capacity, since their NQC is based on ELCC modeling. For example, in 2023, the net dependable capacity of new facilities was about 5,707 MW which was more than 2,778 MW over the assigned NQC values.

Table 18. New NQC Resources Online in 2023

Resource ID	Resource Name	Technology	Sep NQC	Net Dependable Capacity
SEARLS_1_TS3SR1	Trona Solar III	Solar	0.00	2.00
FALBRK_6_FESBT1	Fallbrook Energy Storage	Battery Storage	40.00	40.00
GASKW1_2_GW2BT1	Gaskell West 2 BESS	Battery Storage	20.00	20.00
GASKW1_2_GW2SR1	Gaskell West 2a	Solar	1.37	16.00

GASKW1_2_GW2SR2	Gaskell West 2b	Solar	2.49	29.00
GASKW1_2_GW3SR1	Gaskell West 3	Solar	2.22	20.00
GASKW1_2_GW4SR1	Gaskell West 4	Solar	2.22	20.00
GASKW1_2_GW5SR1	Gaskell West 5	Solar	2.22	20.00
VISTRA_5_PLABT1	Plano Storage 1	Battery Storage	100.40	100.40
VISTRA_5_PLABT3	Plano Storage 3	Battery Storage	74.60	74.60
WSTWND_2_SBSBT1	Sagebrush Solar 2	Battery Storage	80.00	80.00
WSTWND_2_M89BT2	Mojave 89 BESS 2B	Battery Storage	0.00	70.60
WSTWND_2_M89WD2	Mojave 89 Wind	Wind	9.29	75.80
VISTRA_5_PLABT2	Plano Storage 2	Battery Storage	100.40	100.40
VISTRA_5_PLABT4	Plano Storage 4	Battery Storage	74.60	74.60
JOANEC_2_ST3BT3	Santa Ana Storage 3	Battery Storage	40.00	40.00
WESCAN_2_BDSBT1	Bateria Del Sur	Battery Storage	131.00	131.00
OASIS_6_AR8SR1	Arrache 8083 I	Solar	0.00	1.50
OASIS_6_AR8SR2	Arrache 8083 II	Solar	0.00	1.50
SHANDN_2_SBBBM1	San Bernardino Biogas	Biomass	0.00	2.60
KRAMER_1_R1BX3	Resurgence 1 BESS	Battery Storage	75.00	75.00
CHINO_2_PESBT1	Pomona Energy Storage 2	Battery Storage	10.00	20.00
SANBRN_2_SS2SB4	Sanborn Solar 2 Edwards Sanborn S4	Hybrid	20.98	36.00
SISPRG_2_DS3SR4	Daggett Solar 3 e PV	Solar	1.04	17.00
LCKHT1_2_LH1SR1	Lockhart Solar 1 PV	Solar	9.44	85.00
STANTN_2_SBEBX2	Stanton Battery Energy Storage	Battery Storage	68.80	68.80
YELPIN_2_YP2BT1	Yellow Pine 2 BESS	Battery Storage	65.00	65.00
LCKHT1_2_LH1SR2	Lockhart Solar 2	Solar	8.32	75.00
YELPIN_2_YP2SR1	Yellow Pine 2	Solar	10.21	125.00
RDWAY_1_SCKSR1	Sheep Creek	Solar	0.00	3.00
KRAMER_1_R1PX3	Resurgence 1 PV	Solar	5.76	90.00
CRELMN_6_AABBT1	Air Attack Base	Battery Storage	0.00	0.47
DELSUR_6_HORSR1	Horn	Solar	0.00	1.50
SISPRG_2_DS3BT2	Daggett Solar 3 b BESS	Battery Storage	60.00	59.90
SISPRG_2_DS3BT4	Daggett Solar 3 e BESS	Battery Storage	15.00	15.00
SISPRG_2_DS3SR2	Daggett Solar 3 b PV	Solar	8.82	110.00
NORCNV_1_NCVBT1	North Central Valley	Battery Storage	132.00	132.00
KRAMER_1_R2BX2	Resurgence 2 BESS	Battery Storage	40.00	40.00
OCOTLO_6_OCWSB1	Ocotillo Wells Solar and BESS	Hybrid	50.00	50.00

SISPRG_2_DS3BT3	Daggett Solar 3 cd BESS	Battery Storage	12.50	12.50
SISPRG_2_DS3SR3	Daggett Solar 3 cd PV	Solar	4.84	50.00
KRAMER_1_R2PX2	Resurgence 2 PV	Solar	3.07	48.00
FIFTHS_2_FSSBT	Fifth Standard Battery	Battery Storage	137.00	137.00
KNTSTH_6_WALSR1	Westlands Almond	Solar	0.00	19.88
FIFTHS_2_FSSR1	Fifth Standard Solar	Solar	2.23	150.00
SANBRN_2_SS2BT3	Sanborn Solar 2 SBESS 3	Battery Storage	169.00	169.00
SUNCAT_2_A2BSR2	Arlington Solar Unit 2B	Solar	8.00	133.00
SISPRG_2_DS3SR1	Daggett Solar 3 a PV	Solar	10.18	123.00
TULARE_2_TFCBM1	LB Trigen Fuel Cell 1	Biogas	0.00	2.80
OASIS_6_VINSR1	Vinam	Solar	0.00	1.50
OBERON_5_O1BBX2	Oberon 1 BESS	Battery Storage	125.00	125.00
OBERON_5_O2BBX2	Oberon 2 BESS	Battery Storage	125.00	125.00
OBERON_5_O1SSX2	Oberon 1A Solar	Solar	12.42	150.00
OBERON_5_O1SSR3	Oberon 1B Solar	Solar	8.28	100.00
OBERON_5_O2SSR4	Oberon 2A Solar	Solar	10.35	125.00
OBERON_5_O2SSR5	Oberon 2B Solar	Solar	10.35	125.00
SANBRN_2_EESSB2	Edsan 2 Edwards Sanborn E1B	Hybrid	94.63	166.00
BARRE_2_ALASB1	Los Alamitos 1	Hybrid	5.83	10.00
DELAMO_2_ALASB2	Los Alamitos 2	Hybrid	5.83	10.00
EDWARD_2_ESSSB2	Sanborn Solar 2	Hybrid	34.94	132.00
SISPRG_2_DS3BT1	Daggett Solar 3 a BESS	Battery Storage	61.50	61.16
SANBRN_2_SS2BT4	Sanborn Solar 2 SBESS 4	Battery Storage	47.00	47.00
EDWARD_2_ESSSB1	Sanborn Solar 2 Edwards 5	Hybrid	51.89	116.00
CMBLND_2_DS2SR2	Daggett 2 b PV	Solar	5.35	65.00
CMBLND_2_DS2BT1	Daggett 2 a BESS	Battery Storage	52.00	52.00
CMBLND_2_DS2BT2	Daggett 2 b BESS	Battery Storage	33.00	33.00
CMBLND_2_DS2SR1	Daggett 2 a PV	Solar	4.28	65.00
CMBLND_2_DS2BT3	Daggett 2 c BESS	Battery Storage	46.00	46.00
CMBLND_2_DS2SR3	Daggett 2 c PV	Solar	3.18	52.00
OASIS_6_AR4SR3	Arrache 4013	Solar	0.00	1.50
SOLBLU_2_WSBBX2	Westlands Solar Blue BESS	Battery Storage	225.00	225.00
SOLBLU_2_WSBSX2	Westlands Solar Blue	Solar	15.05	250.00
CASCES_6_CESBT1	Cascade Energy Storage	Battery Storage	25.00	25.00
CHESTN_2_CHWBX2	Chestnut Westside BESS	Battery Storage	135.00	135.00

CHESTN_2_CHWSX2	Chestnut Westside PV	Solar	9.02	150.00
STRAUS_1_STRWD1	Strauss Wind, LLC	Wind	20.69	95.25
MCFLND_5_MFSBT1	McFarland Solar A BESS	Battery Storage	100.00	100.00
OASIS_6_AR4SR2	Arrache 4006 II	Solar	0.00	1.00
MCFLND_5_MFSSR1	McFarland Solar A PV	Solar	22.20	200.00
POLRIS_2_ASEBT1	Antelope Solar 2 Estrella BESS	Battery Storage	28.00	28.00
POLRIS_2_ASESR1	Antelope Solar 2 Estrella	Solar	4.64	56.00

Source: 2022-2023 NQC lists posted to the CAISO website.[46]

Table 19. Resources Retired in 2023

Resource ID	Resource Name	Technology	NQC	Status	Off-line Date
PALALT_7_COBUG	Cooperatively Owned Back Up Generator	Natural Gas	4.5	Retired	1/1/2023
VISTA_2_FCELL	CSUSB fuel cell	Fuel Cell	0	Retired	3/1/2023
CHINO_2_SOLAR	Chino RT Solar 1	Solar	0.14	Retired	3/31/2023
VISTA_2_RIALTO	Rialto RT Solar	Solar	0.14	Retired	3/31/2023
ETIWND_2_RTS015	SPVP015	Solar	0.43	Retired	3/31/2023
SBERDO_2_REDLND	Redlands RT Solar	Solar	0.29	Retired	3/31/2023
ANTLPE_2_QF	ANTELOPE QFS	Wind	0.67	Retired	4/6/2023
SBERDO_2_RTS011	SPVP011	Solar	0.5	Retired	4/20/2023
ETIWND_2_RTS023	SPVP023 Fontana RT Solar	Solar	0.36	Retired	4/20/2023
MIRLOM_2_RTS033	SPVP033	Solar	0.14	Retired	4/20/2023
ETIWND_2_RTS010	SPVP010 Fontana RT Solar	Solar	0.22	Retired	4/20/2023
ETIWND_2_RTS026	SPVP026	Solar	0.86	Retired	4/20/2023
SBERDO_2_RTS005	SPVP005 Redlands RT Solar	Solar	0.36	Retired	4/20/2023
ETIWND_2_RTS017	SPVP017	Solar	0.5	Retired	4/20/2023
ETIWND_2_RTS027	SPVP027	Solar	0.25	Retired	4/20/2023
SBERDO_2_RTS016	SPV016 Redlands RT Solar	Solar	0.22	Retired	4/20/2023
ETIWND_2_RTS018	SPVP018 Fontana RT Solar	Solar	0.22	Retired	4/20/2023
MIRLOM_2_RTS032	SPVP032	Solar	0.22	Retired	4/20/2023
SBERDO_2_RTS007	SPVP007 Redlands RT Solar	Solar	0.36	Retired	4/20/2023

[46] See http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx and http://www.caiso.com/planning/Pages/ReliabilityRequirements/ReliabilityRequirementsArchive.aspx.

SBERDO_2_RTS013	SPVP013	Solar	0.5	Retired	7/5/2023
SBERDO_2_RTS048	SPVP048	Solar	0	Retired	7/5/2023
VISTA_2_RTS028	SPVP028	Solar	0.5	Retired	7/5/2023
DTCHWD_2_BT4WND	Brookfield Tehachapi 4	Wind	1.01	Retired	10/31/2023
CSCCOG_1_UNIT 1	Santa Clara's Cogen	Solar	6	Retired	11/11/2023
UNCHEM_1_UNIT	CONTRA COSTA CARBON PLANT	CHP	14.7	Retired	12/31/2023
REDOND_7_UNIT 5	REDONDO GEN STA. UNIT 5	Steam Turbine	178.87	Retired	12/31/2023
REDOND_7_UNIT 6	REDONDO GEN STA. UNIT 6	Steam Turbine	174.29	Retired	12/31/2023
REDOND_7_UNIT 8	REDONDO GEN STA. UNIT 8	Steam Turbine	480	Retired	12/31/2023

Source: CAISO Announced Retirement and Mothball list. [47]

The once-through-cooling (OTC) units that were expected to retire in 2020 were extended to the end of 2026 for reliability reasons. The Statewide Advisory Committee on Cooling Intake Structures (SACCWIS) recommended the following extensions:

- Alamitos Units 3, 4, and 5 for three years, through December 31, 2026;
- Huntington Beach Unit 2 for three years, through December 31, 2026;
- Ormond Beach Units 1 and 2 for three years, through December 31, 2026; and
- On December 16, 2021, the CPUC approved two resource adequacy PPAs between SCE and Redondo Beach for Units 5 and 6 for the period of April 1, 2022, through December 31, 2022, to meet SCE's system, Los Angeles Basin local, and flexible resource adequacy requirements. The SACCWIS does not recommend a change in compliance dates for Redondo Beach.[48]

We also established the State's strategic reliability reserve for these resources where Department of Water Resources (DWR) was given general funds to contract with these units and put them in the reliability reserve (essentially only use them for emergencies).

5.2 Aggregate NQC Values 2017 through 2023

In 2019, D.19-11-016 authorized 3,300 MW of new procurement for 2021-2023. In 2021, D.21-06-035 authorized 11,000 MW of new resources procurement for 2023-2026. In

[47] https://www.caiso.com/documents/announced-retirement-and-mothball-list.xlsx

[48] SACCWIS report, September 30, 2022, p.40-47, 2022 Special Report of the Statewide Advisory Committee on Cooling Water Intake Structures

2023, D.23-02-040 authorized another 4,000 MW of new procurement for 2026-2027. 2023 reflects the beginning of these new resource additions. Table 20 shows aggregate NQC values from the CAISO NQC lists for 2017 through 2023.[49] The total 2023 NQC (as reported on the CAISO NQC list) increased by 697 MW from the 2022 NQC list.

Table 20. Final NQC Values for 2017-2023

Year	Total NQC (MW) AUG	Total Number of Scheduling Resource IDs	Net NQC Change (MW)	Net Change in CAISO IDs on List
2017	56,011	1,139		
2018	54,095	1,464	-1,916	325
2019	51,840	1,948	-2,255	484
2020	49,625	1,995	-2,215	47
2021	47,327	1,721	-2,298	-274
2022	49,433	1,804	2,106	83
2023	50,130	1,882	697	78
2017-2023			**-5,881**	**743**

Source: NQC lists from 2017 through 2023.[50]

6 COMPLIANCE WITH RA REQUIREMENTS

6.1 Overview of the RA Filing Process

The RA filing process consists of multiple submissions, calculations, and validations carried out by different entities. The CEC administers the adopted LSE load forecast process used to establish system RA requirements. CAISO performs an annual local and

[49] Note that MW changes in NQC lists do not align with the calendar year changes described in section 5.1 since the NQC list for each year is prepared in the fall of the previous year.

[50] NQC lists change throughout the year, so the Total NQC will vary depending on the month that the measurement was taken. The lists used in Table 20 are the August NQC of the final NQC lists.

flexible capacity study that is used to inform LSE local and flexible RA requirements g; Energy Division uses load ratios, provided by the annual load forecast, to calculate DR, CAM, and RMR allocations and to calculate local and flexible RA requirements. The RA requirements and allocations are sent to LSEs annual. Energy Division also calculates annual QC values for all physical resources and works with CAISO to develop a NQC list used for RA compliance validation.

LSEs are required to submit annual and monthly compliance filings to the CPUC which are then validated against RA requirements and CAISO resource supply plans (submitted to CAISO by suppliers).

As in prior years, Energy Division hosted a workshop to review general compliance requirements and to highlight changes to procedures and filing rules specific to the 2023 compliance year. In addition to the workshop, Energy Division regularly updates the RA Filing Guide and Templates to assist LSEs in demonstrating compliance with RA program requirements.

The final 2023 RA Filing Guide and Templates were made available to LSEs in October 2022 and incorporated changes to implement the new RA rules discussed in Section 2.2.[51] As in previous years, the CPUC required all filings to be submitted simultaneously to the CAISO and CEC.

6.2 Compliance Review

CPUC staff, in coordination with the CEC and CAISO, reviewed all compliance filings received in accordance with the established RA program procedures, including:

- Verifying timely submission of filings,
- Matching resources listed against the NQC list,
- Verifying matching supply plans, and
- Requesting corrections from LSEs as needed.

A crucial step in this process relies on the CAISO's collection and organization of supply plans submitted by scheduling coordinators for resource suppliers. Energy

[51] Available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage/resource-adequacy-compliance-materials

Division verifies compliance, sends deficiency and correction notices, and approves compliant filings based on validation against CAISO supply plans. Non-compliant filings are discussed in Subsections 6.3 and 6.4.

6.3 Enforcement and Compliance

A core requirement of the RA program is that LSEs must procure sufficient capacity to meet their load and reserve obligations. Due to the short timeframes in which the CPUC and CAISO staff must verify compliance and, if necessary, conduct backstop procurement, it is essential that filings be submitted on time and with accurate information.

Non-compliance occurs when an LSE submits a filing with a procurement deficiency (i.e., insufficient capacity to meet its RA obligations), fails to file, files late, or does not adhere to filing requirements. These forms of non-compliance generally result in enforcement actions or citations issued by the CPUC.

Although CAISO does not typically conduct backstop procurement, such interventions would likely occur more frequently if the CPUC did not strictly enforce RA program compliance.

6.4 Enforcement Actions in 2013 through 2023 Compliance Years

Pursuant to CPUC Resolution E-4195[52], D.11-06-022, and D.14-06-050, Energy Division refers potential violations of the RA program to the CPUC's Consumer Protection and Enforcement Division (CPED), which pursues enforcement actions on behalf of the Commission. The penalty structure outlined in Section 2.2 is used to enforce the RA program.

Beginning in 2023, the Commission publishes the following citation information on its RA citation website. This information is published no earlier than October 1 of the

[52] See: https://docs.cpuc.ca.gov/word_pdf/FINAL_RESOLUTION/93662.pdf.

applicable compliance year and includes the type of RA deficiency, month of deficiency, deficiency amount (MW), and any points accrued.[53]

6.4.1 2023 CPUC Decision to Increase Information about RA Citations and Non-Compliance

There have been 509 RA program violations that have resulted in 144 CPED citations between 2010 and 2023. Historically, the CPUC has made certain information about RA citations and penalties public on the CPUC's RA Program website, including links to the CPUC's CPED website. The information available from CPED's list of citations includes energy citation number, date of citation issuance, LSE name, citation amount ($), and a status update on whether the citation was paid and/or appealed. The CPED citations often bundle numerous violations into a single citation.

In June 2023, the Commission observed in D. 23-06-029 that there had been a large increase in RA Program non-compliance due to LSE procurement deficiencies in recent years. Furthermore, the number and type of violations were obscured behind the limited information provided in the citation listings. The CPUC ordered staff to make information public about the magnitude and type of RA deficiencies, so that policymakers and stakeholders could have sufficient information to understand and address RA program violations.[54] The Commission found that more transparency into LSEs' compliance with the RA program is critical to providing insight into reliability risks related to LSEs' RA deficiencies and RA program violations."[55]

6.4.2 Types of Deficiencies and Citations

As shown in Table 21, CPUC LSEs are required to provide information to demonstrate compliance with RA requirements on a Year-Ahead and Month-Ahead basis, including procurement requirements for 1) System, 2) Local, and 3) Flexible resources. Once Energy Division reviews LSE filings and issues a deficiency notice to an LSE, the LSE has five business days to cure the deficiency.

[53] D.23-06-029, OP 19.

[54] D.23-06-029 at 63.

[55] D.23-06-029 at 64.

Table 21. Types of Deficiencies and Scheduled Penalties

Deficiency in either System, Local or Flexible RA Filing (Modifying Appendix A in Resolution E-4195)			
	System RA Penalty	**Local RA Penalty**	**Flexible RA Penalty**
Capacity Deficiency Cured within five business days from the date of notification by the Energy Division	$5,000 per incident if the deficiency is 10MW or smaller, $10,000 for a deficiency larger than 10 MW. For the second and each subsequent deficiency in any calendar year, penalties will be $10,000 per incident if the deficiency is 10 MW or smaller, $20,000 for a deficiency larger than 10 MW.		
Capacity Deficiency Not Cured or Replaced after five business days from the date of notification	$8.88/kW-month (Summer) and $4.44/kW-month (non-Summer)[56]	$4.25/kW-month	$3.33/kW-month
Programmatic Deficiency (Late or Incorrect Filing)	$1,000 per incident plus $500 per day for the first ten days the filing was late and $1,000 for each day thereafter.		

Note: This table reflects the current penalty structure in place as of November 2023. The citations listed in the database include citations that were issued under prior penalty structures.

D.21-06-029 adopted the following points penalty structure for system RA deficiencies and it is added to the current penalty structure:

Months	Points for Each Instance of System RA Deficiency
Non-Summer (November – April)	1
Summer (May – October)	2

Tier	Accrued Points	System RA Penalty Price

[56] Summer is defined as May – October, and Non-Summer is defined as November-April.

1	0-5	Applicable system RA penalty price
2	6-10	2x the applicable system RA penalty price
3	11+	3x the applicable system RA penalty price

If an LSE's deficiency is less than 1% of the LSE's system RA requirement, no points will be accrued. Points shall only be accrued for month-ahead deficiencies, not year-ahead deficiencies. Points shall expire 24 months after the violation. Accrued points within an RA compliance year shall be carried over to the next RA compliance year. The provider of last resort shall not accrue points for a deficiency resulting from unexpected load returns for which a system RA waiver is granted.

On June 29, 2023, the Commission adopted D.23-06-29, which revises the existing penalty structure and is effective beginning with the July 2023 RA filing period.

Ordering Paragraph 17 of the decision states:

Penalty points accrued by an LSE will be applied to an LSE's month-ahead and/or year-ahead Resource Adequacy (RA) penalties. If an LSE enters a higher tier during a year in which it incurs year-ahead deficiencies, the higher penalty will apply beginning with the monthly deficiency when the LSE enters the higher tier. The month in which an LSE accrues points that brings the LSE into the next tier, the higher penalty will apply to the deficient month for which the points were accrued.

In addition, D.23-06-029 Ordering Paragraph 18 adopts that:

All year-ahead Resource Adequacy (RA) deficiencies will be charged at the Tier 1 price, and in the month-ahead RA process, the load-serving entity (LSE) will pay the difference between its month-ahead tier penalty and the Tier 1 penalty that was already paid on its year-ahead RA deficiency, plus the LSE's current tier price on any incremental month-ahead RA deficiency. The following formula will be applied:

$$\textit{Year-Ahead penalty} = \textit{Deficiency}^{\textit{Year-Ahead}} \times \textit{Tier 1 Price}$$
$$\textit{Month-Ahead penalty} = [(\textit{Deficiency}^{\textit{Year-Ahead}} \times \textit{Tier Price}^{\textit{Month-Ahead}}) - \textit{Year-Ahead penalty}] + (\textit{Deficiency}^{\textit{Month-Ahead incremental}} \times \textit{Tier Price}^{\textit{Month-Ahead}})$$

6.4.3 Impact of RA Program Non-Compliance

LSEs that fail to procure RA capacity requirements put the electric grid at risk of emergency conditions, including rotating outages or electric grid blackouts. There is a

chance that if even a single LSE fails to procure, the collective electricity grid will be short capacity to serve load. If the CAISO has insufficient capacity to serve electricity load, it declares various states of emergency, including activating rotating outages to avoid uncontrolled blackouts. The grid operator cannot limit the emergency to a particular set of LSE customers. To avoid such emergencies, the electric grid operator relies on any excess capacity voluntarily supplied by other LSEs, and/or can seek to procure backstop emergency capacity resources under various terms and conditions.

A RA capacity deficient LSE may be cited by the CPUC (usually after some time delay), but it may still result in the LSE not paying the actual cost of the RA capacity for the compliance period. The RA program penalty is meant to be a deterrent, however even with the application of a penalty, a deficient LSE may be leaning on other LSEs' procurement or relying on various backstop procurement mechanisms, and such mechanisms do not usually have a method to charge specifically an RA-deficient LSE.

6.4.4 Key Findings and Observations RA Program Citation Database

The RA Citation Database shows there have been 509 separate instances of RA program violations since 2010, resulting in 144 total RA Citations issued. The CPED issues a single citation for all violations in a compliance filing (i.e. Year-Ahead or Month-Ahead filing), whereas the RA Program Citation Database itemizes each citation. Which means that the RA Program Citation Database may contain multiple rows or violations for each assigned citation number.

Table 22 summarizes citations issued by the CPUC since 2010. From 2010 through 2023, the CPUC issued 136 citations for 493 program violations Table 22 reflects RA program citations from 2010 to 2023 by LSE name and type. The current number of CPUC jurisdictional LSEs is 38, but it has varied over time. Based on the information in Table 22, Electric Service Providers (ESPs) have accrued the highest count of RA citations and number of violations while CCAs have accrued the highest total deficiency measured by MWs per month (those not cured at all, or deficiencies cured after five business days) and highest total citation fines ($).

Table 22. Citations by LSE and Type, 2010-2023

	Total Citation Amount ($)	Number of Energy Citations	Number of Violations	Sum of Citation Deficiency (Not Cured/ or Cured After 5 Business Days) (Cumulative MW-Month)
CCA				
Central Coast Community Energy	$ 15,235,246.20	10	13	1,642.98
Clean Energy Alliance	$ 616,627.20	2	2	69.44
Clean Power Alliance of Southern California	$ 10,000.00	1	4	0
CleanPowerSF	$ 3,526,568.00	6	8	392.35
Desert Community Energy	$ 650,104.80	3	5	73.21
East Bay Community Energy	$ 6,370,452.10	8	14	794.88
Orange County Power Authority	$ 2,545,659.60	3	6	312.67
Peninsula Clean Energy Authority	$ 2,960,407.20	2	4	331.69
Pioneer Community Energy	$ 2,561,702.40	3	3	384.64
Redwood Coast Energy Authority	$ 263,114.40	2	2	29.63
San Diego Community Power	$ 5,052,845.60	4	8	549.87
San Jose Clean Energy	$ 8,675,568.00	4	9	1,290.22
Silicon Valley Clean Energy Authority	$ 3,588,498.40	3	7	386.43
Sonoma Clean Power Authority	$ 442,012.00	1	3	48.65
Valley Clean Energy Alliance	$ 6,660.00	2	2	2
Western Community Energy	$ 1,529,866.40	1	4	208.78
CCA Total	**$ 54,035,332.30**	**55**	**94**	**6,517.44**
ESP				
3 Phases Renewables, LLC	$ 32,500.00	4	4	0
Agera Energy	$ 58,481.80	3	7	8.23
American PowerNet Management, LP	$ 66,410.20	2	10	8.47
Commerce Energy, Inc.	$ 11,000.00	3	3	0
Commercial Energy of California	$ 1,972,455.50	20	198	434.73
Commercial Energy of Montana, Inc	$ 41,824.80	2	2	6.28
Constellation New Energy, Inc.	$ 2,733,408.00	2	2	304.1
Direct Energy Business, LLC	$ 2,355,319.00	5	5	268.36

EDF Industrial Power Services, LLC	$	149,463.60	6	17	22.35
Glacial Energy of California	$	10,000.00	2	2	0
Glacial Power	$	6,660.00	1	1	1
Just Energy Solutions, Inc.	$	777,856.40	17	85	143.2
Liberty Power Holdings	$	14,000.00	3	5	0
Pilot Power Group, Inc.	$	753,866.30	5	19	100.12
Shell Energy North America (SENA)	$	584,132.50	3	40	131.09
The Regents of the University of California	$	307,780.80	4	8	34.09
Tiger Natural Gas	$	9,500.00	4	4	0
ESP Total	**$**	**9,884,658.90**	**86**	**412**	**1,462.02**
IOU					
San Diego Gas & Electric	$	16,000.00	2	2	0
Southern California Edison Company	$	10,000.00	1	1	0
IOU Total	**$**	**26,000.00**	**3**	**3**	**0**
Grand Total	**$**	**63,945,991.20**	**144**	**509**	**7,979.46**

Since 2010, there have been 3 citations issued to IOUs with penalties totaling $26,000, 86 citations issued to ESPs totaling over $9.8 million dollars, and 54 citations issued to CCAs totaling over $54 million. Since 2010, RA citations have resulted in over $63 million in fine payments being remitted to the State of California General Fund. These values are broken down further in Table 23.

Table 23. Citation Amount ($), Number of Citations, Sum of Capacity Deficiencies, by LSE Type, Year

		Total Citation Amount ($)	Number of Energy Citations	Number of Violations	Sum of Citation Deficiency (Not Cured/ or Cured After 5 Business Days) (Cumulative MW-Month)
CCA					
2017	$	10,000.00	1	1	0
2018	$	2,424,240.00	2	2	364
2019	$	8,487,867.00	5	11	1291.5
2020	$	2,087,430.50	5	10	311.44
2021	$	10,982,536.80	13	19	1,269.61

2022	$	8,720,474.80	11	17	998.46
2023	$	21,322,783.20	18	34	2,282.43
CCA Total	**$**	**54,035,332.30**	**55**	**94**	**6,517.44**
ESP					
2010	$	6,000.00	2	2	0
2011	$	11,160.00	3	3	1
2012	$	16,500.00	3	3	0
2013	$	10,000.00	2	4	0
2014	$	5,000.00	1	1	0
2015	$	31,000.00	5	5	0
2016	$	18,000.00	4	4	0
2017	$	125,609.60	3	3	18.56
2018	$	172,529.00	8	19	26.15
2019	$	1,094,449.80	20	97	208.1
2020	$	1,201,175.40	18	70	246.68
2021	$	1,463,020.70	7	112	265.65
2022	$	2,664,535.60	7	67	345.81
2023	$	3,065,678.80	7	22	350.07
ESP Total	**$**	**9,884,658.90**	**86**	**412**	**1,462.02**
IOU					
2012	$	5,000.00	1	1	0
2016	$	10,000.00	1	1	0
2022	$	11,000.00	1	1	0
IOU Total	**$**	**26,000.00**	**3**	**3**	**0**
Grand Total	**$**	**63,945,991.20**	**144**	**509**	**7,979.46**

Table 24 shows that in 2023, twenty-four citations were issued for penalties totaling $24,388,462.[57] Citations and penalties have increased in recent years, likely driven by issues related to supply and demand balances due to resource retirements, load forecast increases, increase in the number of LSEs serving load, and changes in resource counting methodologies.

[57] For a list of all penalties, please see: UEB Citations-Fines-Restitutions -- Active (1).xlsx (ca.gov)
For waivers, please see: Local Waivers Issued

Table 24. Citations Issued for the RA Program from 2012-2023

Compliance Year	Citations Issued	LSEs Cited	Citation Penalties
2012	4	Glacial Energy of CA, Shell Energy, SDG&E, Direct Energy Business	$14,600
2013	5	SDG&E, Commerce Energy, 3 Phases Renewables, Liberty Power (2)	$26,500
2014	1	3 Phases Renewables	$5,000
2015	6	3 Phases Renewables (2), Commerce Energy (2), EDF Industrial, Glacial Energy	$38,000
2016	3	Tiger Natural Gas, Glacial Energy, Shell Energy	$13,500
2017	6	Commercial Energy of Montana (2), CleanPowerSF, Southern California Edison, Direct Energy Business, Tiger Natural Gas	$150,110
2018	10	AmericanPowerNet Management, Just Energy Solutions (5), Direct Energy Business, Pilot Power Group, Pioneer Community Energy (2)	$2,596,739
2019	26	AmericanPowerNet Management, Just Energy Solutions (5), Direct Energy Business, Pilot Power Group, Pioneer Community Energy (2)	$9,553,046
2020	20	American PowerNet Management, Clean Power Alliance of Southern California, Commercial Energy (10), East Bay Community Energy, Just Energy Solutions (3), Monterey Bay Community Energy, Peninsula Clean Energy, San Jose Clean Energy, Tiger Natural Gas	$2,707,435
2021	21	Central Coast Community Energy (3), Commercial Energy (3), East Bay Community Energy (4), EDF Industrial Power Services, Pilot Power Group (4), San Diego Community Power (2), San Jose Clean Energy, Silicon Valley Clean Energy Authority, Shell Energy North America (SENA), Western Community Energy	$13,425,486

Compliance Year	Citations Issued	LSEs Cited	Citation Penalties
2022	18	Central Coast Community Energy (3), CleanPowerSF (4), Constellation New Energy, Direct Energy Business (2), East Bay Community Energy, EDF Industrial Power Services (2), Orange County Power Authority (2), San Diego Community Power, San Diego Gas and Electric, Silicon Valley Clean Energy Authority	$10,977,140
2023	24	Central Coast Community Energy (3), Desert Community Energy (2), Orange County Power Authority, Sonoma Clean Power Authority, San Jose Clean Energy, Peninsula Clean Energy, Clean Power Alliance of Southern California, East Bay Community Energy, EDF Industrial Power Services, LLC (2), Regents of the University of California (3), Constellation New Energy Inc., Silicon Valley Clean Energy, CleanPowerSF, Redwood Coast Energy Authority (2), San Diego Community Power, Clean Energy Alliance (2)	$24,388,462
Total	**144**		**$63,896,018**

Source: UEB Citations-Fines-Restitutions -- Active (1).xlsx (ca.gov)

7 RETAIL ELECTRICITY SUPPLIERS: EMISSIONS OF GREENHOUSE GASES

7.1 Introduction

Senate Bill 1158 (SB 1158) directs the CPUC to review the total annual emission of GHGs and the annual GHG emissions intensity reported for each LSE. Similarly, the governing board of each local publicly owned electric utility (POU) must conduct the same review for its respective utility. The legislation authorized the CPUC, for all LSEs, and each POU governing board, to:

> 1) Assess whether reported GHG emissions, in combination with each entity's procurement plans for subsequent years, demonstrate adequate progress toward achieving their respective GHG reduction targets; and
>
> 2) Calculate and publish the percentage of each LSE's Local and System RA requirements from the previous calendar year that were met using capacity from eligible renewable energy resources, other zero-carbon resources, or energy storage resources, as specified.

7.2 Background

Section 1(f)(1) of SB 1158 requires the CPUC to ensure that RA requirements are supported by information on each LSE's anticipated and actual load, as well as the measures taken to achieve compliance. Section 1(f)(2) further requires the CPUC to calculate and annually publish the percentage of each LSE's Local and System RA requirements met with capacity from the following resource types:

- Eligible renewable energy resources as defined under the Renewables Portfolio Standard (RPS) Program (Public Utilities Code Section 399.11 et seq,);
- Other zero-carbon resources, including large hydroelectric and nuclear; and
- Energy storage resources.

In calculating these percentages, the CPUC must include all directly owned or contracted resources, as well as each LSE's allocation of centrally procured resources through mechanisms involving assignment or allocation from a single buyer. The calculation must exclude any share of an LSE's resources that was allocated to another LSE.

Section 1(j) of SB 1158 also directs the commission to establish, in an existing or new proceeding, a mechanism to value load-modifying DR resources. This includes, but is not limited to, the ability of DR to meet distribution and transmission needs and reduce an LSE's RA obligations. In establishing this value, the CPUC must consider how DR supports grid reliability and contributes to the state's GHG reduction goals. Furthermore, the CPUC, CEC, and CAISO must ensure that changes in demand caused by DR are promptly and comprehensively incorporated into the CEC's Integrated Energy Policy Report (IEPR) forecast and into planning proceedings and associated analyses. These agencies are also encouraged to promote the incorporation of such changes into grid operations.

Finally, Section 2 (g)(1) authorizes the CPUC to review the total annual GHG emissions and average GHG intensity reported for each LSE. The CPUC may assess whether these emissions, in conjunction with an LSE's procurement plans, indicate sufficient progress toward achieving the GHG emissions reduction targets required under Public Utilities Code Section 454.52. For CCAs, the CPUC must provide its findings to each CCA's governing board.

The reporting requirements directed by Section 1(f)(1) of SB 1158 are reported in Table 25 for the 2023 RA compliance year. Table 25 summarizes the total annual percentage of the Month-Ahead capacity requirement met by capacity contracted from RPS or zero-emitting resources in 2023. The percentage is calculated by dividing the NQC from RPS or zero-emitting resources by the sum of the aggregated Month-Ahead load forecast and the 16% PRM.

Table 25 values are arranged by LSE name and Type, and cover resources counted using the ELCC modeling methodology (e.g. wind and solar) as well as those counted using the most recent maximum capacity (Pmax) test (e.g. paired battery storage and large hydro). The composition of each LSEs portfolio influences these percentages, with factors like the inclusion of energy storage systems contributing to higher values.

Table 25. Percentage of Month-Ahead Total Requirement met by RPS or Zero Emitting Resources

	Total Annual Percentage
CCA	
CleanPowerSF	56.13%
Sonoma Clean Power Authority	44.89%
Desert Community Energy	41.60%
Central Coast Community Energy	37.15%
Peninsula Clean Energy Authority	34.86%
Silicon Valley Clean Energy Authority	33.46%
Pioneer Community Energy	31.95%
Redwood Coast Energy Authority	28.88%
Valley Clean Energy Alliance	27.02%
Clean Power Alliance of Southern California	25.43%
San Diego Community Power	23.74%
East Bay Community Energy	22.01%
San José Clean Energy	20.87%
Marin Clean Energy	15.97%
Lancaster Choice Energy	15.62%
Pomona Choice Energy	15.34%
Santa Barbara Clean Energy	13.50%
Orange County Power Authority	9.33%
King City Community Power	8.68%
Rancho Mirage Energy Authority	7.98%
Clean Energy Alliance	7.38%
Apple Valley Choice Energy	7.35%
Pico Rivera Innovative Municipal Energy	7.13%
San Jacinto Power	7.11%
City of Palmdale	2.67%
ESP	
Commercial Energy of Montana, Inc	52.47%
3 Phases Renewables, LLC	44.08%
Shell Energy North America	31.05%
Calpine Energy Solutions, LLC	29.55%
The Regents of the University of California	27.68%
Direct Energy Business, LLC	25.72%
EDF Industrial Power Services, LLC	22.75%
Calpine Power America-CA, LLC	21.63%
Pilot Power Group, Inc.	17.05%

Constellation New Energy, Inc.	13.53%
IOU	
Pacific Gas and Electric Company	63.83%
Southern California Edison Company	26.80%
San Diego Gas & Electric Company	25.86%

8 APPENDIX

2023 List of CPUC Jurisdictional LSEs

1. Pacific Gas and Electric Company
2. Southern California Edison Company
3. San Diego Gas & Electric Company
4. 3 Phases Renewables, LLC
5. Apple Valley Choice Energy
6. Calpine Energy Solutions, LLC
7. Calpine Power America-CA, LLC
8. Central Coast Community Energy
9. City of Palmdale
10. Clean Energy Alliance
11. Clean Power Alliance of Southern California
12. CleanPowerSF
13. Commercial Energy of Montana, Inc
14. Constellation New Energy, Inc.
15. Desert Community Energy
16. Direct Energy Business, LLC
17. East Bay Community Energy
18. EDF Industrial Power Services, LLC
19. King City Community Power
20. Lancaster Choice Energy
21. Marin Clean Energy
22. Orange County Power Authority
23. Peninsula Clean Energy Authority
24. Pico Rivera Innovative Municipal Energy
25. Pilot Power Group, Inc.
26. Pioneer Community Energy
27. Pomona Choice Energy
28. Rancho Mirage Energy Authority
29. Redwood Coast Energy Authority
30. San Diego Community Power
31. San Jacinto Power
32. San José Clean Energy

33. Santa Barbara Clean Energy
34. Shell Energy North America
35. Silicon Valley Clean Energy Authority
36. Sonoma Clean Power Authority
37. The Regents of the University of California
38. Valley Clean Energy Alliance