2022 RESOURCE ADEQUACY REPORT

Rev Renewables' Diablo Energy Storage Project, 200 MW/800 MWh in Pittsburg, CA

May 2024

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
CPM	Capacity Procurement Mechanism	MOO	Must-Offer Obligation
CPP	Critical Peak Pricing	MA	Month Ahead
CPUC	California Public Utilities Commission	MW	Megawatt
CSP	Competitive Solicitation Process	NERC	North American Reliability Corporation
DA	Direct Access	NQC	Net Qualifying Capacity
DG	Distributed Generation	PCIA	Power Charge Indifference Adjustment
DR	Demand Response	PMax	Maximum capacity of a resource
DRAM	Demand Response Auction Mechanism	PMin	Minimum capacity of a resource
ED	Energy Division	PRM	Planning Reserve Margin
EE	Energy Efficiency	QC	Qualifying Capacity
ELCC	Effective Load Carrying Capacity	QF	Qualifying Facility
EFC	Effective Flexible Capacity	RA	Resource Adequacy
ESP	Electricity Service Provider	RAR	Resource Adequacy Requirement
ExD	Exceptional Dispatch	RMR	Reliability Must Run
FERC	Federal Energy Regulatory Commission	RPS	Renewable Portfolio Standard
GHG	Greenhouse Gas	RUC	Residual Unit Commitment
HE	Hour Ending	SPD	Save Power Day
IOU	Investor-Owned Utility	SFTP	Secure File Transfer Protocol
IV	Imperial Valley	TAC	Transmission Access Charge

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 2022 RA compliance year. While this report does not make explicit policy recommendations, it provides information relevant to the currently open 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 aggregate and LSE 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 has 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 the report.

- **2022 RA Obligation was Slightly Higher than 2021**

  The overall CEC-adjusted forecast for CPUC-jurisdictional LSEs had an expected peak in September 2022 of 40,585 MW, which represents a 0.55% increase over the peak forecast of 40,363-MW for September 2021.

- **LSE Compliance with RA Obligations**
  - **System Obligations Met:** In 2022, CPUC-jurisdictional LSEs collectively met their System RA obligations for all months. The 2022 peak demand (for CPUC-jurisdictional LSEs, after net load migration adjustments) was forecasted to occur in September 2022, at 40,585 MW. The RA obligation for September, including a 15% planning reserve margin (PRM) on top of peak demand, totaled 46,826 MW and LSEs collectively procured 47,105 MW. For individual LSE compliance, see citation section below.
  - **Local Obligations Met:** The Central Procurement Entity (CPE) framework, adopted in (D).20-06-002, was implemented beginning in 2021. To transition to the adopted framework the CPE was responsible for procurement of 2023 and 2024 Local requirements, however, LSEs were still responsible for procuring their 100% local RA for 2022. CPUC-jurisdictional LSEs collectively met all local RA requirements during the 2022 compliance year. The 2022 local RA procurement obligations for CPUC-jurisdictional LSEs totaled 22,807 MW. LSEs and CAISO procured a monthly minimum of 25,535 MW. Physical resources, cost allocation mechanism (CAM) resources, reliability must-run (RMR) resources, and demand response (DR) resources contributed to this total.

- **Actual Peak Demand in 2022**
  The peak demand in CAISO for 2022 of 51,479 MW, which includes CPUC-jurisdictional and non-CPUC jurisdictional LSEs, occurred on September 6, 2022,

during the hour between 4 and 5 pm.[4] The 2022 CAISO peak was the highest on record, breaking the previous record, which was set in 2006. About 90% of 2022 actual peak load, or approximately 46,331 MW, could be attributed to CPUC-jurisdictional LSEs.

- **Resources Used to Meet LSEs' RA Obligations in 2022**
  - In 2022, total committed RA resources ranged from 30,845 MW in March to 48,068 MW in July, with the variation due to monthly variations in RA obligations that vary with the monthly expected peak load.
  - **LSE Procurement:** Individual LSE bilateral contracting by LSEs made up most of forward capacity procurement.
  - **Capacity Allocations:** Centralized procurement allocations to all LSEs, including CAM and RMR, and DR procurement, where the costs and benefits are passed through to all customers by Transmission Access Charge (TAC) area, also contributed to meeting RA obligations. Specifically, CAM, RMR, and DR resources consisted of 17.8 to 26.6% of total RA capacity requirements.
  - **Unit-Specific Physical Resources:** Between 85 and 93% of all committed RA capacity (depending on the month), including CAM, was procured by LSEs from unit-specific physical resources within the CAISO control area. These values do not include specified imports.
  - **Unspecified Imports:** Unspecified Imports accounted for 0.1 to 7.2% of capacity used to meet RA obligations.

- **Prices for Resource Adequacy**
  - **Increases in RA Prices:** Prices for both system and local RA increased significantly between 2021 and 2022, particularly for the summer months. After many years in which the weighted average price of local RA was higher than the weighted average price of system RA, in 2021, the weighted average price of system RA surpassed that of local RA. In 2022, the prices of local and system RA were nearly identical.

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[4] This peak is the average used over the hour. The technical peak minute is recorded by CAISO as 52,061 MW at 17:50. See http://www.caiso.com/documents/californiaisopeakloadhistory.pdf. When used in this report, the peak will refer to the peak hour measurement.

- **Average RA Prices:** Measured using weighted average price informed by RA only contracts executed from 2021-2023 for the 2022 RA compliance year, Local RA averaged $7.70/kW-month while System RA on average cost $7.68/kW-month.
- **Summer RA Prices:** Prices for both local and system RA are significantly higher in summer months than in winter. In 2022, the weighted average price of system RA in January was $5.87/kw-month but rose to $12.36/kW-month in August and $13.48/kw-month in September. Local RA prices see similar spreads between winter and summer months.
- **Prices Higher in 2022 compared to 2021:** Prices were also significantly higher than in 2021, when the weighted average price of local RA was $6.49/kW-month and of System RA was $6.74/kW-month. For flexible capacity, prices are slightly lower than those for system capacity overall. In the past several years, flexible capacity prices have shown no premium.

- **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.[5]
  - **Citations in 2022:** In total, the CPUC's Enforcement Division issued eighteen citations for 85 violations related to compliance year 2022 for a total of $ $10,977,140.
  - **New Citations Database:** The CPUC issued a new listing of all RA citations in February 2024 that includes all citations issued since 2011 through Summer 2023. 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 that identifies the type of LSEs that had individual citations in 2022 (11 CCAs, 7 ESPs, and 1 IOU),

[5] 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).

including the number of violations (85), the number of MWs of deficiency (over 1,300 MW-months of deficiency), and the financial penalty amount of the citations issued for 2022 RA year violations (almost $11 million). [6]

2 RA PROGRAM BACKGROUND

This section of the 2022 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.[7]

2.1 Resource Adequacy Program Requirements

The CPUC's RA program contains three distinct requirements: System RA requirements (effective June 1, 2006), Local RA requirements (effective January 1, 2007) and Flexible RA requirements (effective January 1, 2015).

Requirement	Determination
System RA	Each LSEs CEC-adjusted forecast plus a 15% 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 reliability

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 the annual filings, LSEs are required to make an annual System, Local, and Flexible compliance showing for the coming year. For the System showing, each LSEs is required to demonstrate that it has procured 90% of its System RA obligation for the five summer months of the coming compliance year. Additionally, each LSE has a

[6] 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

[7] final-2022-ra-guide-clean-101821.pdf (ca.gov)

three-year forward local obligation and must meet 100% of its local requirement for the years one and two and 50% of for year three. Finally, each LSE must demonstrate that it meets 90% of its Flexible RA obligation for all twelve months.

For the monthly filings LSEs must demonstrate they have procured 100% of their monthly System and Flexible RA obligation. Additionally, on a monthly basis from July through December, LSEs must demonstrate they have met their revised (due to load migration) local obligation. Beginning with the 2023 RA compliance year, LSEs in SCE and PGE local distribution areas are no longer required to demonstrate 100% local RA compliance as the Central Procurement Entity (CPE for Local) assumes responsibility for local in those areas.

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 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 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. For LSEs in the SCE and PGE local procurement need only be demonstrated for 2022.	From July to December, LSE must demonstrate 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 filed annually by each LSE and adjusted by the California Energy Commission (CEC). Jurisdictional and non-jurisdictional LSEs must submit historical hourly peak load data for the preceding year, and monthly energy and peak demand forecasts for the coming compliance year based on a "best estimate approach" that are based on reasonable assumptions for load growth and customer retention. The CEC then adjusts the LSE-submitted load forecasts, which form the basis for the final LSE load forecasts used for year-ahead RA compliance. LSEs are also required to submit monthly load forecasts to the CEC that account for load migration throughout the compliance year.

To establish the year-ahead load forecast, the CEC first calculates each LSE's specific monthly coincidence factors using the historic hourly load data filed by each LSE.[8] The adjustment factors are calculated by comparing each LSE's historic hourly peak loads to the historic coincident California Independent System Operator (CAISO) hourly peak loads. These factors make each LSE's peak load forecast reflective of the LSE's contribution to total load when CAISO's load peaks. The CEC then reconciles the aggregate of the jurisdictional LSEs' monthly peak load forecasts against the CEC's monthly 1-in-2, weather normalized peak-load forecast, for each Investor-Owned Utility (IOU) service area. This reconciliation evaluates the reasonableness of the LSEs' forecasts. As part of the reconciliation, if the aggregate LSE forecasts differ significantly from CEC's forecasts for reasons other than load migration, the CEC may adjust individual IOU service area forecasts. Additionally, as specified in D.05-10-042, the CEC makes adjustments to account for the impact of energy efficiency (EE) and distributed generation (DG). The sum of the adjusted forecasts must be within 1% of the CEC service area forecast. If the aggregated LSE forecasts diverge more than 1% from the CEC's monthly weather normalized forecasts, the CEC makes a pro-rata adjustment to reduce the divergence to below 1%.

The CEC uses the aggregated LSE forecasts to create monthly load shares for each transmission access charge (TAC) area, which Energy Division then uses to allocate demand response (DR), cost allocation mechanism (CAM), and reliability must run (RMR) RA credits. Flexible RA requirements are also allocated to LSEs using these 12 monthly load ratio shares. Local obligations are calculated using the load shares for September 2022 of the projected year ahead. The forecasts and allocations together determine both the annual and monthly system RA obligations.

[8] Adopted in D.12-06-025, Ordering Paragraph 4, available at http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/169718.PDF.

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. The adopted process is an LSE's initial year ahead load forecast will serve as the Binding Notice of Intent (BNI) for that LSE in the following year. To account for unforeseen circumstances or new or relevant information in the forecasting process, the CEC will extend the deadline for revisions to the initial forecasts to May 15. Once the initial load forecast is submitted, the LSE is responsible for the RA capacity implied by the initial load forecast – after any adjustments by the CEC and for load migration - regardless of additional changes in an LSE's implementation to new customers. Additionally, the Commission and the CEC will add plausibility review triggers to the forecast adjustment process, which if triggered, may require additional documentation, forecast revisions to better match an implementation plan, or forecast revisions to account for load migration.[9]

2.2 Changes to RA Program for 2022

D. 21-06-029 set system, local, and flexible capacity obligations for 2022, confirmed the 17.5% effective PRM as a target for summer 2022, that was set in the Emergency Reliability Rulemaking via D.21-03-056, and introduced several refinements to the RA program for 2022.[10]

2.2.1 Changes to Cumulative Capacity Buckets for 2022

Programmatic refinements in 2022 included the following changes to the Maximum Cumulative Capacity Buckets (MCC):

- All MCC Buckets are modified to require Saturday availability in addition to Monday through Friday availability. This change was made because the August/September heat waves in 2021 revealed that weekday-only resource availability was insufficient to insure grid reliability. The change to Monday through Saturday availability required updates to MCC buckets for DR and for Buckets 1 and 2. However, DR contracts with an

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

[10] The effective PRM is applied to IOUs only. A combination of RA eligible and non-eligible resources may be used to meet the 17.5% effective PRM.

execution date prior to the decision were exempted from the Saturday availability requirement.

- The minimum availability for Category 1 resources (such as storage) was increased from 40 to 100 hours per month between 4:00 p.m. and 9:00 p.m. and now applies year-round.
- The Maximum Cumulative Capacity Buckets were thus 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, 4 consecutive hours between 4 PM and 9 PM, and at least 100 hours per month. For the month of February, total availability is at least 96 hours.	17.0%
2	Every Monday – Saturday, 8 consecutive hours that include 4 PM – 9 PM	24.9%
3	Every Monday – Saturday, 16 consecutive hours that include 4 PM – 9 PM.	34.8%
4	Every day of the month. Dispatchable resources must be available all 24 hours.	100% (at least 56.1% available all 24 hours)

2.2.2 Changes to Demand Response resources for 2022

Several changes, approved in D. 21.06-029, were made to the qualifying capacity (QC) value for DR resources:

- The 6% component of the PRM adder associated with ancillary services and operating reserves was removed from DR resources effective starting with 2022 compliance year. The 9% component of the PRM adder associated with forced outages and forecast error was retained.

- The transmission loss factor (TLF) and distribution loss factor (DLF) adders, were retained as part of the QC methodology for DR. However, the DLF was required to be incorporated into QC values beginning in 2022, rather than be an adder applied to the load impact values.

2.2.3 Changes to RA Penalty Structures for 2022

D.21-06-029 also made several changes to the penalty structure for System RA deficiencies effective for the 2022 RA compliance year, including adopting an escalating point and tier penalty structure to discourage LSEs incurring repeated system deficiencies. The penalty structure would assign 1 point for each instance of system RA deficiency in the non-summer months (November to April) and 2 points for each deficiency during the summer months (May to October). An LSE with 6-10 points accrued pays double the applicable system RA penalty price while an LSE with 11 or more points accrued would pay triple the RA penalty price.

The following tables summarize the adopted 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
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

The adopted structure also included the following implementation details:

- If a load-serving entity's (LSE) 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.

The RA Citations database released in February 2024 identifies the Citation points accrued to LSEs by date in Table 5, page 9 of the report.

Table 5. Citation Points Accrued LSEs by Date and Citation Amount ($), Citation Point Expiration, and Citation Point Tier Level

Energy Citation Number	Date Issued	Load Serving Entity	Year	Deficiency Month	Citation Amount	Citation Points	Citation Points Expiration Date (Month-Year)	Citation Point Tier Level
E-4195-0127	9/21/2022	Central Coast Community Energy	2022	September	$506,098.40	2	Sep-24	Tier 2
E-4195-0146	8/14/2023		2023	July	$159,129.60	2	Aug-25	
E-4195-0151	11/8/2023		2023	August	$1,455,609.60	2	Aug-25	
E-4195-0154	11/16/2023	Clean Energy Alliance	2023	August	$226,262.40	2	Aug-25	Tier 1
E-4195-0155	12/8/2023		2023	September	$390,364.80	2	Sep-25	
E-4195-0128	9/22/2022	CleanPowerSF	2022	September	$1,456,320.00	2	Sep-24	Tier 1
E-4195-0147	8/30/2023		2023	August	$745,387.20	2	Aug-25	
E-4195-0156	12/20/2023	Desert Community Energy	2023	August	$151,048.80	2	Aug-25	Tier 1
E-4195-0157	1/3/2024		2023	September	$124,408.80	2	Sep-25	
E-4195-0123	9/8/2022	Direct Energy Business, LLC	2022	August	$499,144.80	2	Aug-24	Tier 1
E-4195-0124	9/13/2022		2022	September	$1,733,020.80	2	Sep-24	
E-4195-0129	9/30/2022	East Bay Community Energy	2022	September	$878,587.20	2	Sep-24	Tier 1
E-4195-0125	9/16/2022	Orange County Power Authority	2022	September	$415,406.40	2	Sep-24	Tier 1
E-4195-0148	9/15/2023	Redwood Coast Energy Authority	2023	August	$139,149.60	2	Aug-25	Tier 1
E-4195-0150	10/27/2023		2023	September	$123,964.80	2	Sep-25	
E-4195-0145	8/13/2023	The Regents of the University of California	2023	July	-	2	Jul-25	Tier 2
E-4195-0149	9/20/2023		2023	August	$34,898.40	2	Aug-25	
E-4195-0153	11/13/2023		2023	September	$69,796.80	2	Sep-25	

3 LOAD FORECAST AND RESOURCE ADEQUACY PROGRAM REQUIREMENTS

3.1 Yearly and Monthly Load Forecast Process in 2022

RA requirements for 2022 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 2022 revised annual forecasts were due on August 16, 2021. These revised forecasts informed the final 2022 year-ahead allocations and requirements- and were used by LSE's in the year-ahead filing process. CPUC staff sent initial allocations to LSEs on July 22, 2022, and final allocations to LSEs on September 23, 2021.

LSEs file historical load information	**March 15, 2021**
LSEs file 2022 year-ahead load forecast	**April 19, 2021**
LSEs receive 2022 year-ahead RA obligations	**July 22, 2021**
Final date to file revised forecasts for 2022	**August 16, 2021**
LSEs receive revised 2022 RA obligations	**September 23, 2021**

To determine monthly RA requirements, the CPUC allows for LSEs to revise their annual load forecast on a monthly time frame to account for load migration. [12] This process was adopted in D.05-10-042[13] and is further described in the 2022 RA Guide. [14] Specifically, LSEs must submit a revised forecast prior to each compliance filing

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

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

month.[15] These load forecast adjustments are solely for load migration between LSEs, not changing demographic or electrical conditions. Per D.10-06-036,[16] LSEs must submit any load forecast changes or adjustments at least 25 days before the due date of the month-ahead compliance filings.

LSEs submit these monthly forecasts to the CEC and CPUC for evaluation; the CEC then reviews the revised forecasts and customer load migrating assumptions. The revised monthly load forecasts update the year-ahead forecast and inform monthly RA obligations. Energy Division also uses these monthly forecasts to recalculate load shares, which are then used to reallocate CAM and RMR credits on a quarterly basis. The revised load forecasts also inform the local true-up process discussed in Section 3.5.2.

3.2 Yearly Load Forecast

Table 1 shows the aggregate LSE submissions for 2022 and the adjustments that were made by the CEC across the three IOU service areas.[17] These adjustments include plausibility adjustments, demand side management adjustments, and a prorated adjustment to each LSE's forecast to ensure that the total for all forecasts is within 1% of the CEC's overall service area forecast. The forecast also includes a coincident adjustment that calculates each LSE's expected contribution towards the CAISO peak. The overall CEC-adjusted forecast for CPUC-jurisdictional LSEs had an expected peak in September 2022 of 40,585 MW, which represented a 0.55% increase from the peak forecast of 40,363 MW for September 2021.[18]

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[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.

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

[18] The 2021 RA report can be found at: 2021 Resource Adequacy Report (ca.gov)

Table 1. 2022 Aggregated Load Forecast Data (MW) - Results of Energy Commission Review and Adjustment to the 2022 Year-Ahead Load Forecast

Element	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Submitted LSE Forecast	26,886	25,784	25,818	27,550	30,434	35,281	38,891	40,081	39,592	31,565	26,109	26,786
Non-Coincident Peak Demand	28,600	27,993	26,920	29,727	33,028	38,036	40,984	40,997	41,643	34,057	28,177	29,555
Coincidence Adjustment	(732)	(818)	(775)	(1,202)	(968)	(1,298)	(1,399)	(1,132)	(1,058)	(1,191)	(716)	(681)
Adjustment for Plausibility and Migrating Load	1,341	1,644	828	1,636	2,306	2,206	1,710	922	1,707	2,090	1,349	2,357
EE/DG/DR Adjustment	(84)	(85)	(111)	(102)	(54)	(149)	(164)	(169)	(147)	(55)	(108)	(93)
Pro Rata Adjustment	457	649	385	643	341	699	546	162	491	457	827	505
Final Load Forecast Used for Compliance	**27,867**	**27,175**	**26,145**	**28,525**	**32,059**	**36,738**	**39,585**	**39,864**	**40,585**	**32,866**	**27,461**	**28,874**

Source: CEC Staff.

3.3 Year-Ahead Plausibility Adjustments and Monthly Load Migration

Table 2 below presents the aggregate monthly plausibility adjustments for all LSEs from 2013 to 2022 and calculates the 2022 monthly plausibility adjustments as a percentage of the monthly year-ahead forecast for 2022.

In 2022, the CEC's plausibility adjustments increased the load forecast for all months. The 2022 monthly plausibility adjustments as a percentage of that month's aggregated year-ahead forecast after adjustment ranged from 2.31% for August to 8.16% for December. Plausibility adjustments most commonly indicate mismatches between an LSE's own forecast assumptions and the CEC's assumptions regarding economic growth, responsiveness of load to weather conditions, and customer retention or migration. The CEC develops a reference estimate for each LSE based on historic loads and load migration data and makes an adjustment when the LSE's forecast is significantly different. IOU forecasts are also revised to account for differences between the CEC and the IOU forecasts of the total service area and aggregate estimates of departing load.

Table 2. CEC Plausibility Adjustments, 2013-2022 (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	1,349	2,357
2022 Plaus Adj ÷ Load	**4.81%**	**6.05%**	**3.17%**	**5.73%**	**7.19%**	**6.00%**	**4.32%**	**2.31%**	**4.21%**	**6.36%**	**4.91%**	**8.16%**

Source: Year-ahead CEC load forecasts, 2013-2022.

Table 3. Summary of Load Migration Adjustments in 2022 (MW)

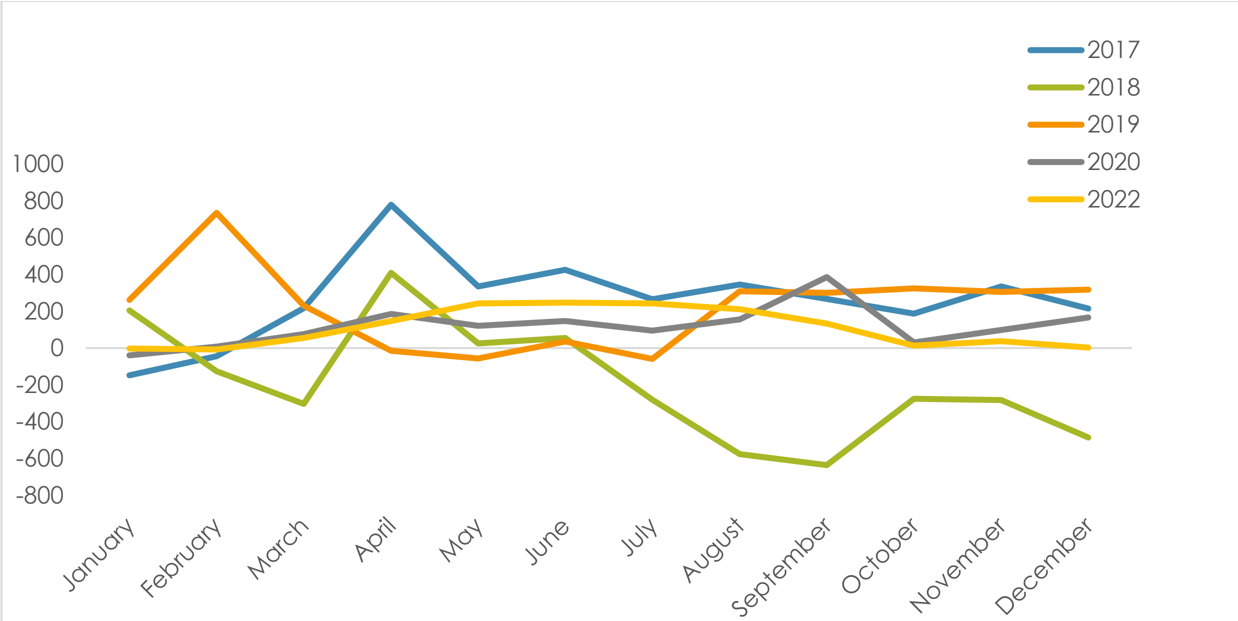
Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Final YA Load Forecast	27,867	27,175	26,145	28,525	32,059	36,738	39,585	39,864	40,585	32,866	27,461	28,874
Monthly Adjustments	(3)	(8)	55	147	243	247	243	212	133	13	38	4
Final Forecasts in Monthly RA Filings	27,864	27,167	26,201	28,672	32,303	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 2022.

Monthly load forecasts, adjusted for load migration, form the basis of monthly RA obligations. Table 3 shows the monthly total load forecasts and the monthly adjustments for load migration for 2022. There were only small net load migration adjustments from the year-ahead load forecast to the final monthly load forecasts used to calculate monthly RA obligations. The largest such adjustment, on a percentage basis, was an increase of 0.76% for May 2022. On a megawatt basis, the net monthly load migration adjustments ranged from - 8 in February to 247 MW in June. Net load migration should be close to zero since it is defined as customers transferring directly from one LSE to another.

Discrepancies in the adjustments made by LSEs gaining and losing customers, however, can cause overall load migration adjustments to deviate from zero. In recent years, the CPUC and CEC have worked to identify the reasons for these discrepancies and to encourage closer coordination between LSEs during forecast development. Figure 1 illustrates the net monthly load migration between LSEs from 2017 through 2022. Monthly load migration remained below 800 MW (or 3% of total load) during this period. There was little load migration in 2022 (yellow line on the graph). The largest monthly net load migration occurred in June and was 247 MW, or 0.67% of total load.

Figure 1. Net Load Migration Adjustments per Month (MW), 2017-2022



Source: Monthly forecast adjustments submitted by LSEs, 2017-2022

3.4 System RA Requirements for CPUC-Jurisdictional LSEs

CPUC-jurisdictional LSEs met their collective system RA requirements for every month of 2022. 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 shows the total CPUC-jurisdictional RA procurement for each month of 2022, broken down by physical resources within the CAISO's control area (including CAM resources), DR, capacity procurement mechanism (CPM), and reliability must run (RMR) resources, imports, and the additional preferred local capacity requirement (LCR) credit for the Southern California Edison (SCE) TAC area. CAM resources are deducted from a non-IOU LSE's RA requirement, while IOUs receive an increase in their RA requirement that is offset by their showing the full CAM resources (on behalf of all LSEs' customers) in their RA filings. Physical resources include CAM resources, which are reported separately. The RA obligation includes the aggregate monthly load forecast plus the 15% planning

[19] System requirements include a 15% Planning Reserve Margin above jurisdictional LSEs' aggregate monthly peak forecast.

reserve margin (PRM). DR resources, including Demand Response Auction Mechanism (DRAM) resources, are reported with a 9% PRM applied.[20]

Table 4. 2022 RA Filing Summary - CPUC-jurisdictional Entities (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
RAR without DR,CAM, & RMR	32,044	31,242	30,131	32,972	37,148	42,533	45,802	46,088	46,826	37,811	31,624	33,209
CAM	6,922	6,908	6,925	6,750	6,729	6,747	6,425	6,459	6,467	6,385	7,014	7,014
Phys. Res. (w/ CAM)	30,194	29,370	27,991	30,420	34,699	40,566	42,775	42,148	40,009	35,181	29,724	31,521
Import (Resource Specific)	1,111	1,152	1,508	1,200	1,271	1,622	1,694	1,631	1,483	1,061	1,086	1,189
Import (Unspecified)	47	48	195	351	390	561	1,460	1,806	3,401	1,174	57	38
Total Imports	1,158	1,200	1,703	1,551	1,661	2,183	3,154	3,437	4,885	2,235	1,143	1,227
DR plus 9% PRM	992	1,017	996	1,199	1,315	1,559	1,722	1,780	1,793	1,462	1,198	1,015
RMR	154	154	154	154	426	416	416	416	418	429	432	434
CPM	0	0	0	0	0	0	0	0	0	0	0	0
Total	32,498	31,741	30,845	33,324	38,102	44,725	48,068	47,782	47,105	39,307	32,496	34,196
Total/RAR	101.4%	101.6%	102.4%	101.1%	102.6%	105.2%	104.9%	103.7%	100.6%	104.0%	102.8%	103.0%

Source: LSE Monthly RA Filings.

In 2022, total committed RA resources ranged from 30,845 MW in March to 48,068 MW in July. Between 85% and 93% of all committed RA capacity (including CAM) was procured by LSEs from unit-specific physical resources within the CAISO control area, with a higher percentage in off-peak months and a lower percentage in peak months when CAISO resources are supplemented by imports. Unspecified Imports accounted for 0.1% to 7.2% of capacity, and Demand Response made up 3 to 3.8% of capacity. CAM and RMR resources made up between 14.2 and 23 percent of total RA capacity procured. These resources enabled CPUC-jurisdictional LSEs to collectively meet between 100.6% and 105.2% of total procurement obligations in each summer month.

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

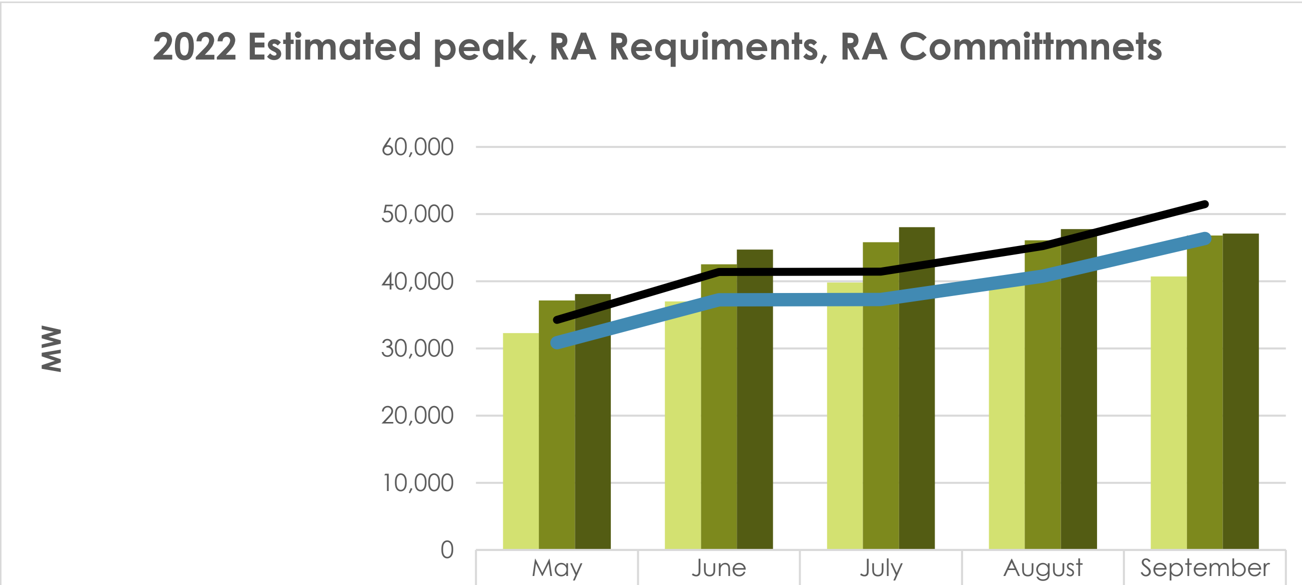
The actual peak demand in CAISO of 51,479 MW, which includes CPUC-jurisdictional and non-CPUC jurisdictional LSEs, occurred on September 6, 2022, just before 5 pm.[21] The 2022 CAISO peak was the highest on record, breaking the previous record set in 2006.[22] Around 90% of 2022 actual peak load, or about 46,331 MW, could be attributed to CPUC-jurisdictional LSEs.

Figure 2 compares the 2022 total load forecast, procurement obligation (forecast plus PRM), and total committed RA capacity for CPUC-jurisdictional LSEs (the green bars on the graph) with the peak load for CPUC-jurisdictional LSEs (Blue line). The CAISO-jurisdictional peak load (black line) is also included in this figure as a reference. The CPUC-jurisdictional peak is estimated using the CPUC-jurisdictional LSE's coincident peak demand forecasts as a percentage of overall CAISO coincident peak demand forecast. The difference between the total RA resources committed (dark-green bar) and LSEs' collective forward commitment obligation (lighter green bar) reflects the excess capacity committed to meet the monthly RA requirement. The CAISO jurisdictional peak (black line) includes non-CPUC jurisdictional load and therefore can be higher than CPUC RA obligations and total RA committed.

[21] 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.

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

Figure 2. 2022 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.)	32,303	36,985	39,828	40,077	40,718
Forward Commitment Obligation	37,148	42,533	45,802	46,088	46,826
Total RA Resources Committed	38,102	44,725	48,068	47,782	47,105
Est. Peak Load (CPUC-juris.)	30,851	37,257	37,303	40,744	46,370
Actual Peak Load (CAISO)	34,250	41,362	41,413	45,233	51,479

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

3.5 Local RA Program – CPUC-Jurisdictional LSEs

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 distribution service areas. This framework was implemented beginning in 2021. To transition to the adopted framework the CPE was responsible for procurement of 2023 and 2024 Local requirements, however, LSEs were still responsible for procuring their 100% local RA for 2022. Specifically, LSEs were required to file an annual local RA filing showing that they have met 100 percent of their local capacity requirement for each of the 12 months of the coming compliance year, inclusive of credit allocations.

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.[23] 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.21-06-029, the CPUC adopted the 2022 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 2022 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 2022, CPUC-Jurisdictional LSEs

Local Areas in 2022	Total LCR	CPUC-Jurisdictional Local RAR	Minimum Physical Resources per Month	Local RMR & CAM Credit	Local DR	Minimum Procurement/ Local RAR
LA Basin	6,646	5,983	7,485	3,647	661	125.1%
Big Creek/Ventura	2,173	1,930	3,798	310	149	196.8%
San Diego-IV	3,993	3,993	3,815	1,017	13	95.5%
Greater Bay Area	7,231	6,399	5,204	1,362	26	81.3%
Fresno	1,987	1,761	2,749	35	23	156.2%
Sierra	1,220	1,054	936	49	10	88.8%
Stockton	562	507	371	-	11	73.2%

[23] Local Capacity Requirement (LCR) studies and materials for 2022 and previous years are posted at California ISO - Reliability Requirements (caiso.com).

Local Areas in 2022	Total LCR	CPUC-Jurisdictional Local RAR	Minimum Physical Resources per Month	Local RMR & CAM Credit	Local DR	Minimum Procurement/ Local RAR
Kern	356	322	346	-	56	107.3%
Humboldt	111	104	170	-	2	163.2%
NCNB	834	755	662	-	6	88%
Totals	25,113	22,807	25,535	6,419	957	112.0%

Source: 2022 Year Ahead RA filings.

3.5.2 Local and Flexible RA True-Ups

As part of the partial reopening of direct access in 2010, the CPUC adopted a true-up mechanism in D.10-03-022 to adjust each LSE's local RA obligation to account for load migration. Since the true-up process was revised in D.14-06-050, there has been one mid-year reallocation per year.

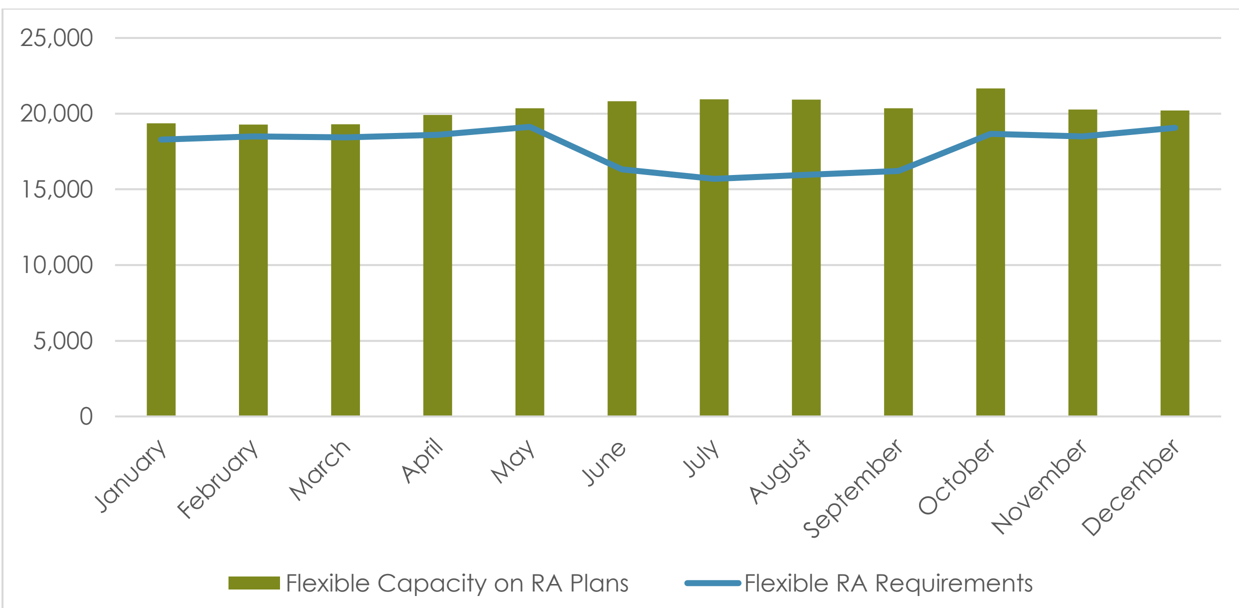
The current true-up process requires LSEs to file revised load forecasts for the second half of the year (July to December), which the CEC uses to establish revised load ratios for those months. In turn, the CPUC uses the revised August load ratios to adjust each LSE's local capacity requirements. Since 2015, the true-up process has also included flexible RA requirements. The difference between the original allocations and the new requirements is allocated to LSEs as an incremental local and flexible RA requirement, which the LSEs must meet in their monthly compliance filings for July through December.

In the allocation cycle for 2022, LSEs submitted revised June through December forecasts to the CEC on March 17, 2022. After reviewing these values, the CEC revised the September load shares. Energy Division used the revised load shares to recalculate individual LSE local requirements, which were then sent to LSEs on April 9, 2022. LSEs were instructed to incorporate these incremental local and flexible allocations into their July to December RA month-ahead (MA) compliance filings. Through its review, Energy Division staff verified that each LSE met its reallocated local and flexible requirement for July to December.

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 percent of their monthly flexible capacity requirements in the year-ahead process and 100 percent of their flexible capacity requirements in the month-ahead process.[24] Flexible capacity needs are developed through CAISO's annual Flexible Capacity Study and are defined as the quantity of economically dispatched resources needed by CAISO to manage grid reliability during the largest three-hour continuous ramp in each month. Flexible resources must be able to ramp up or sustain output for 3 hours. Figure 3 shows the flexible capacity requirement (green bars) and the flexible capacity shown (blue line) on month-ahead RA plans by CPUC-jurisdictional LSEs for each month of 2022.

Figure 3. Flexible RA Procurement in 2022, CPUC-Jurisdictional LSEs



Source: 2022 RA filings.

[24] 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.

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 must-offer obligation requires owners of these resources to submit self-schedules or bids into the CAISO market, making these resources available for dispatch. In other words, the MOO commits these RA resources to CAISO market mechanisms. Prices for bilateral RA contracts are discussed in Section 4.1.

The CAISO utilizes 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 (e.g., Exceptional Dispatch (ExD), CPM, and RMR contracts) to meet reliability needs that are not satisfied by the Day Ahead, Real Time, and RUC 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 Cost Allocation Mechanism (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 of 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 including combined heat and power (CHP) and DRAM resources are similarly allocated. Current CAM resources are summarized in Section 4.4.

4.1 Resource Adequacy Contract Price Analysis

Energy Division issued routine data requests to all CPUC-jurisdictional LSEs requesting monthly capacity prices paid by (or to) LSEs for every RA capacity contract executed during 2021-2022 [2]for use in calculating the Power Charge Indifference Adjustment (PCIA) RA adder and this RA price analysis. The RA capacity contracts are for delivery years 2022-2026. These data requests are for RA only contracts and do not include energy only (EO), deliverability rights contracts, or other contracts that are not RA-only.

Since RA prices can vary by month, the data request asked for specific monthly prices from each contract. All prices are reported in nominal dollars per kW-month.

Energy Division received responses from all LSEs. With the exception of Table 6, which includes contracts executed through Q3 of 2023 for delivery in 2022-2024, data used in this analysis were restricted to contracts executed in 2021 or 2022 for delivery in 2022. Because Table 6 includes data from contracts executed in 2022, the weighted average, average, and 85th percentile prices all differ slightly from the same data categories in other tables in this section.

4.1.1 System Capacity Prices

Table 6 provides a summary of system capacity prices for RA delivered during the 2022-2024 compliance years with contracts executed from 2021 to Q3 of 2023.

Table 6. RA System Capacity Prices in 2022-2024

	2022 Capacity	2023 Capacity	2024 Capacity
Contracted Capacity (MW)	99,685	182,449	198,293
Weighted Average Price ($/kW-month)	$7.67	$10.06	$9.04
Average Price ($/kW-month)	$8.31	$11.03	$9.73
85% of MW at or below ($/kW-month)	$10.75	$16.67	$13.00

Source: 2022-2024 price data submitted by LSEs.

System capacity is comprised of both resources that count only towards system capacity (or both system and flexible capacity) and those located in local areas -that can count towards local RA requirements. Table 7 provides aggregated capacity prices for all responses, categorized as system-only or local capacity, by zonal area (north or south of Path 26 (NP-26 and SP-26, respectively)). The 2022 Net Qualifying Capacity list was used to identify resources' local area and Path 26 zone.[25] The data set represents 98,862 MW-months of capacity under contract. Of that capacity, 60% is located in the NP-26 zone, and 39.5% is located in SP-26. Just under 0.5% is comprised of capacity imports to

[25] The 2022 Net Qualifying Capacity list can be found at Resource Adequacy Compliance Materials (ca.gov).

CAISO. Of the capacity located within CAISO, 73% is located in local capacity areas, with 27% located in the CAISO System area.

The weighted average price for all capacity is $7.68/kW-month. The weighted average price for SP-26 capacity is $7.49/kW-month, which is about 4 percent lower than the NP-26 weighted average price of $7.80/kW-month. In contrast, in 2021, SP-26 capacity was about 5 percent higher SP-26 capacity. The weighted average price of local RA is $7.70/kW-month which is nearly the same as the weighted average price for system RA, which was $7.64/kW-month. For all RA, the five-year ahead weighted average price for delivery in 2022-2026 with contract execution including Q1-3 of 2023 is $8.74/kW-month.

Table 7. Aggregated RA Contract Prices, 2022

	All RA				Local RA			CAISO System RA		
	Total[26]	**NP-26**	**SP-26**	**Import**	**Subtotal**	**NP26**	**SP26**	**Subtotal**	**NP26**	**SP26**
Contracted Capacity (MW)	98,862	59,359	39,026	478	62,820	36,506	26,313	35,565	22,852	12,713
Percentage of Total Capacity in Data Set	100%	60.0%	39.5%	0.5%	63.5%	36.9%	26.6%	36.0%	23.1%	12.9%
Number of Monthly Values	5,532	3,716	1,773	43	3,695	2,493	1,202	1,794	1,223	571
Weighted Average Price ($/kW-month)	$7.68	$7.80	$7.49	$6.83	$7.70	$7.76	$7.63	$7.64	$7.87	$7.22
Average Price ($/kW-month)	$8.31	$8.46	$8.01	$7.23	$8.37	$8.47	$8.16	$8.21	$8.44	$7.70
85% of MW at or below ($/kW-month)	$10.75	$11.00	$10.50	$8.05	$10.50	$10.50	$9.96	$13.00	$13.85	$10.88

Source: 2022 price data submitted by LSEs.

The monthly weighted average capacity prices for CAISO resources are shown in Table

[26] Table 7 differs slightly from Table 6 because it excludes contracts, such as Demand Response contracts, that don't specify whether they are North or South of Path 26.

8, below.

Table 8. RA Capacity Prices by Month and Path 26 Zone, 2022

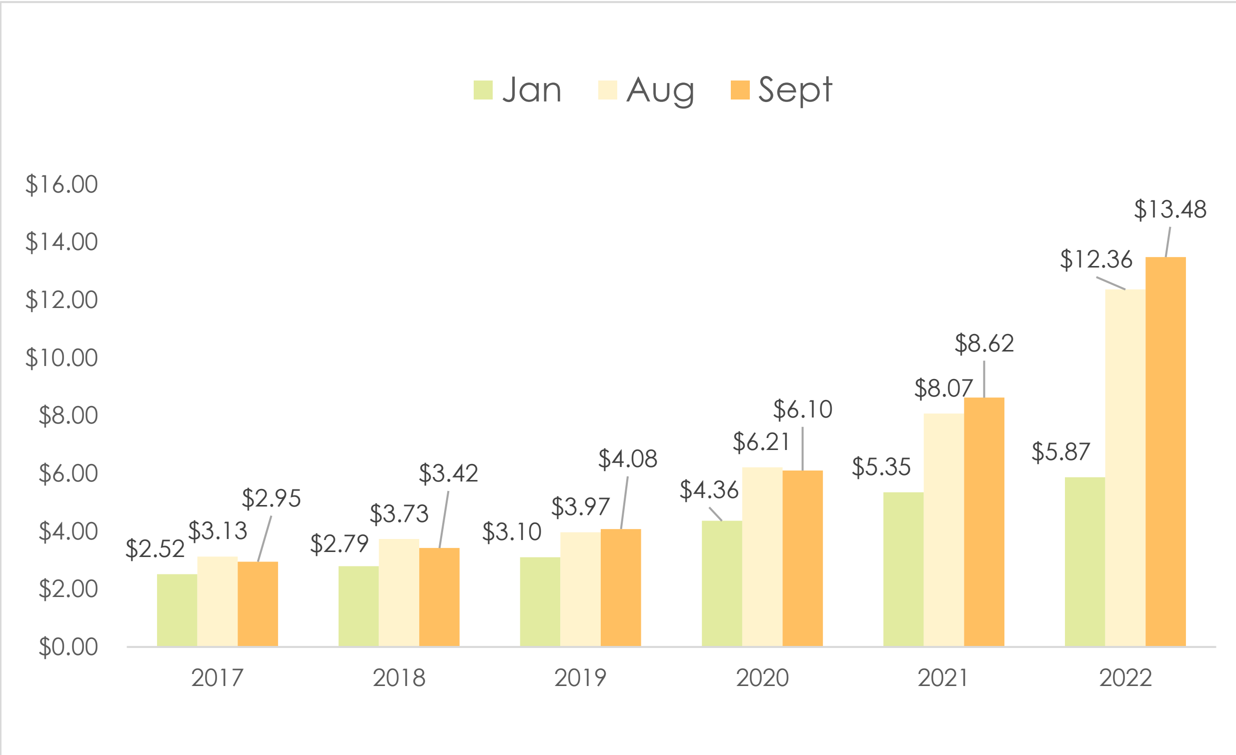
	Path 26 Zone	Contracted Capacity (MW)	Percentage of Total Capacity in Data Set	Weighted Average Price ($/kW-month)	Average Price ($/kW-month)	85th Percentile ($/kW-month)
Jan	North	3,921	3.99%	$6.10	$6.29	$8.31
	South	2,121	2.16%	$5.44	$5.72	$8.00
	Total	6,042	6.14%	$5.87	$6.11	$8.01
Feb	North	3,986	4.05%	$5.93	$6.18	$8.25
	South	2,437	2.48%	$4.70	$5.01	$8.00
	Total	6,424	6.53%	$5.46	$5.75	$8.00
Mar	North	4,769	4.85%	$5.51	$5.75	$8.00
	South	4,343	4.41%	$4.59	$5.11	$8.00
	Total	9,112	9.26%	$5.07	$5.52	$8.00
Apr	North	4,955	5.04%	$5.60	$5.83	$8.00
	South	3,542	3.60%	$5.27	$5.50	$8.00
	Total	8,497	8.64%	$5.46	$5.74	$8.00
May	North	5,335	5.42%	$5.75	$5.85	$8.00
	South	3,374	3.43%	$6.18	$5.86	$8.00
	Total	8,708	8.85%	$5.92	$5.86	$8.00
Jun	North	4,761	4.84%	$6.66	$7.13	$9.00
	South	3,222	3.27%	$6.99	$7.04	$8.77
	Total	7,983	8.11%	$6.79	$7.10	$9.00
Jul	North	5,069	5.15%	$9.23	$9.59	$12.00
	South	3,540	3.60%	$9.48	$10.22	$13.75
	Total	8,609	8.75%	$9.33	$9.79	$13.00
Aug	North	6,472	6.58%	$12.54	$13.32	$20.90
	South	3,633	3.69%	$12.05	$13.64	$22.00

	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)
	Total	10,106	10.27%	$12.36	$13.42	$21.00
Sep	North	5,220	5.31%	$13.46	$15.95	$30.00
	South	3,397	3.45%	$13.51	$14.39	$30.00
	Total	8,617	8.76%	$13.48	$15.41	$30.00
Oct	North	5,587	5.68%	$8.37	$9.06	$13.00
	South	2,991	3.04%	$8.74	$8.87	$12.80
	Total	8,578	8.72%	$8.50	$9.00	$13.00
Nov	North	4,810	4.89%	$5.75	$6.11	$8.54
	South	3,440	3.50%	$5.80	$5.44	$8.00
	Total	8,250	8.39%	$5.77	$5.86	$8.25
Dec	North	4,472	4.55%	$5.97	$6.30	$8.55
	South	2,987	3.04%	$6.08	$5.67	$8.00
	Total	7,459	7.58%	$6.02	$6.10	$8.50

Source: 2022 price data submitted by LSEs.

Figure 4 shows the monthly weighted average price of System RA for January, August, and September, from 2017 through 2022. The weighted average price of system RA for all three months has increased each year, and at an accelerating pace. Until 2021, the weighted average of System RA Prices was highest in August. Since 2021, September prices have been slightly higher than August prices. The weighted average price of system RA in September 2022 was $13.48, which represents a 357% increase over the September 2017 weighted average. The weighted average of August prices have increased by 295% since 2017 from $3.13 to $12.36/kW-month. The year-on-year increase in weighted average price between 2021 and 2022 was 56% for September and 53% for August. In contrast, January RA prices increased a more modest 113% between 2017 and 2022, from $2.52/kW-month to $5.87/kW-month. These price increases are likely be driven by tight supply conditions attributed to resource retirements, load forecast increases, and changes in counting conventions that have reduced the RA value of certain resources.

Figure 4: Weighted Average Price of System RA ($/kW-month), January, August and September 2017- 2022



Source: 2017-2022 price data submitted by LSEs.

4.1.2 Local Capacity Prices

Table 9 reports capacity prices by local capacity area. A CAISO system price for capacity outside of the local areas, excluding imports, is included for comparison. The vast majority of local capacity contracted MWs reported were in the Bay Area and LA Basin Local Areas. The Bay Area weighted average price was $7.31/kW-month. In the LA Basin it was $7.54/kW-month. Overall, the lowest weighted average prices for local RA were found in San Diego ($7.14/kW-month) and Humboldt ($7.16/kW-month) while the highest was found in the Sierra local area ($11.88/kW-month).

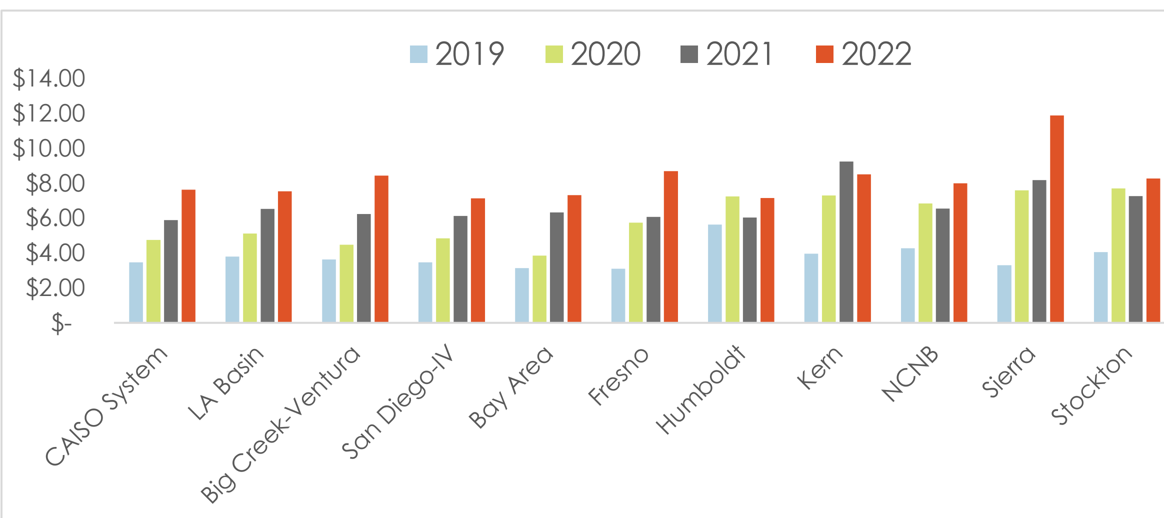
Table 9. Capacity Prices by Local Area, 2022

	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)
CAISO System	36,387	37%	$7.62	$8.21	$13.00
LA Basin	15,831	16%	$7.54	$7.96	$9.00
Big Creek-Ventura	4,830	5%	$8.44	$9.71	$16.50
San Diego-IV	5,710	6%	$7.14	$7.06	$9.68
Bay Area	27,043	27%	$7.31	$8.05	$10.00
Fresno	3,378	3%	$8.70	$8.61	$10.35
Humboldt	129	0%	$7.16	$8.69	$9.00
Kern	990	1%	$8.50	$7.98	$10.00
NCNB	2,363	2%	$8.00	$8.48	$10.72
Sierra	1,877	2%	$11.88	$10.66	$16.00
Stockton	670	1%	$8.27	$8.42	$10.71

Source: 2022 price data submitted by LSEs.

Figure 5 shows weighted average RA prices for 10 local areas and, for comparison purposes, CAISO system RA, for the compliance years 2019-2022. Prices for the LA Basin, Big Creek-Ventura, San Diego-IV, and the Greater Bay Area — which collectively account for most local RA requirements and contracted capacity — have closely tracked CAISO system prices.

Figure 5. Weighted Average Price of Local RA ($/kW-month), 2019-2022



Source: 2017-2022 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.

Table 10. Local RA Capacity Prices by Month, 2022

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CAISO System	Weighted Average	$5.48	$4.67	$4.29	$4.40	$5.00	$6.38	$9.41	$13.24	$14.67	$8.81	$4.99	$5.45
	85th Percentile	$7.50	$7.50	$7.50	$7.50	$7.50	$8.55	$12.00	$21.00	$30.00	$13.00	$7.64	$7.81
LA Basin	Weighted Average	$5.71	$5.42	$5.50	$6.97	$7.10	$7.50	$8.74	$10.31	$10.70	$8.36	$6.73	$6.84
	85th Percentile	$8.00	$8.00	$8.84	$8.00	$8.00	$8.79	$11.38	$18.30	$30.00	$10.00	$8.00	$8.00
Big Creek-Ventura	Weighted Average	$5.05	$5.47	$4.84	$6.41	$8.59	$7.80	$12.18	$14.13	$13.47	$9.83	$6.10	$4.90
	85th Percentile	$8.00	$8.00	$8.00	$8.15	$8.84	$11.72	$16.50	$22.00	$22.05	$15.20	$8.19	$8.00
San Diego-IV	Weighted Average	$5.73	$3.74	$4.05	$5.00	$5.79	$6.46	$8.76	$12.90	$14.28	$7.85	$4.90	$5.12
	85th Percentile	$8.05	$7.02	$7.83	$8.05	$8.05	$8.05	$11.43	$25.00	$29.91	$11.60	$8.05	$8.05
Bay Area	Weighted Average	$6.18	$6.18	$6.21	$6.16	$6.28	$6.93	$8.95	$10.43	$9.76	$7.61	$6.34	$6.52
	85th Percentile	$9.46	$8.89	$8.85	$8.50	$8.51	$9.50	$14.60	$16.50	$18.10	$12.75	$8.75	$9.38
Fresno	Weighted Average	$5.33	$5.66	$5.04	$4.79	$5.21	$5.68	$9.29	$16.54	$19.28	$9.04	$5.25	$4.58
	85th Percentile	$8.50	$8.80	$8.50	$8.50	$8.50	$8.50	$11.50	$27.49	$32.75	$10.94	$9.30	$9.27
Humboldt	Weighted Average	$5.08	$5.06	$4.54	$4.72	$4.80	$7.16	$8.70	$14.46	$22.65	$7.90	$4.17	$4.60
	85th Percentile	$7.49	$7.24	$7.40	$7.40	$7.55	$9.00	$9.00	$18.25	$28.50	$8.20	$5.60	$7.36
Kern	Weighted Average	$5.66	$5.48	$4.57	$4.72	$4.75	$5.05	$9.63	$14.32	$25.78	$7.64	$5.27	$5.68
	85th Percentile	$7.14	$7.13	$6.97	$6.57	$6.45	$7.70	$10.00	$17.20	$30.00	$10.49	$7.29	$8.20
NCNB	Weighted Average	$7.69	$8.04	$6.87	$7.00	$7.31	$7.73	$8.71	$9.48	$10.59	$8.61	$7.56	$7.64
	85th Percentile	$9.63	$9.65	$8.00	$8.00	$8.00	$9.64	$10.47	$15.65	$30.00	$10.91	$9.70	$9.74
Sierra	Weighted Average	$8.22	$6.88	$5.91	$6.11	$5.28	$7.30	$10.50	$17.41	$27.09	$11.19	$4.88	$6.97
	85th Percentile	$9.05	$8.67	$8.50	$8.50	$8.50	$9.35	$12.94	$27.57	$35.05	$14.50	$10.50	$9.52
Stockton	Weighted Average	$7.06	$7.34	$6.70	$5.96	$6.37	$7.37	$9.38	$11.23	$13.22	$8.31	$6.54	$5.82
	85th Percentile	$8.16	$8.24	$8.24	$8.70	$8.70	$9.00	$12.05	$16.68	$26.80	$11.00	$8.20	$8.13

Source: 2022 price data submitted by LSEs

4.1.3 Flexible Capacity Prices

Table 11 shows capacity prices for flexible capacity located outside of local areas. Prices for flexible capacity are considerably lower than those for non-flexible system capacity. The 2022 weighted average price for flexible capacity is $6.61/kW-month for non-flexible capacity is $8.00/kW-month.

Table 11. Flexible vs. Non-Flexible CAISO System Prices (Excluding Imports), 2022

	Flexible Capacity	Non-Flexible Capacity
Contracted Capacity (MW)	12,503	23,885
Percentage of Total Capacity in Data Set	34%	65%
Weighted Average Price ($/kW-month)	$6.61	$8.00
Average Price ($/kW-month)	$7.26	$8.66
85% of MW at or below ($/kW-month)	$8.10	$15.00

Source: 2022 price data submitted by LSEs.

4.2 CAISO Out of Market Procurement – RMR Designations

The CAISO performs RMR studies to determine whether resources are needed for reliability. Generating resources with existing RMR contracts must be re-designated by the CAISO for the next compliance year and presented to the CAISO Board of Governors for approval by October 1st of each year. Designations for new RMR contracts are more flexible and may arise at any time. RMR resources can be dispatched by the CAISO for reliability and are paid for by customers in the transmission area or by all customers, depending upon the underlying reason for the designation. D.06-06-064 authorized the CPUC to allocate the RMR benefits as an RMR credit that is applied towards RA requirements.

Pursuant to the stated policy preference of the CPUC,[27] local RA requirements began to supplant RMR contracting in the 2007 compliance year and there was a significant decline in 2007 RMR designations. That trend continued through the 2011 compliance year, with only one remaining RMR contract.[28]

In 2017, for the 2018 compliance year, RMR designations increased dramatically. Four units received RMR Condition 2 designations. 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, 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 CAISO extended and signed five RMR contracts with generating facilities for the 2022 compliance year, including: Green Leaf II Cogen (49.2 MW), CSU Channel Islands (27.5 MW), Midway Sunset Cogen (262.10 MW in August), Dynegy Oakland, LLC's units 1 and 3 (110 MW), and Kingsburg Cogen (34.5 MW). Table 12 shows the plants with RMR Designations for 2022.

Table 12. CAISO RMR Designations for 2022

Unit	MW
Greenleaf II Cogen	49.2
Channel Islands Power	27.5
Midway Sunset Cogen	248
Kingsburg Cogen	34.5
Oakland, Unit 1	55
Oakland, Unit 3	55

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

[28] 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:

- Insufficient local capacity area resources in an annual or monthly RA plan;
- Collective deficiency in local capacity area resources;
- Insufficient RA resources in an LSE's annual or monthly RA plan;
- A CPM significant event;
- A reliability or operational need for an exceptional dispatch CPM;
- 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[29]

Eligible capacity is limited to resources that are not already under a 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.

Under the exceptional dispatch CPM, if Eligible Capacity receives an Exceptional Dispatch CPM designation under CAISO Tariff Section 43A.2.5, then the CAISO shall designate as CPM Capacity the greater of the PMin of the resource providing the capacity or the quantity of capacity needed from the resource providing the capacity (beyond whatever quantity of capacity is already Committed RA Capacity, capacity subject to a RMR Contract, or has been subject to a self-schedule or market-based commitment at the time of the Exceptional Dispatch) to address the reliability issue as determined in an engineering assessment.[30]

When the CAISO makes CPM designations, it relies on capacity willingly offered to the CAISO by resource scheduling coordinators. To attract such capacity, the CAISO

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[29] CAISO Reliability BPM, version 74. https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Reliability%20Requirements.

[30] ISO Tariff Section 43.A.2.5.2.1, Section43A-CapacityProcurementMechanism-asof-Aug15-2022.pdf (caiso.com)

conducts annual, monthly and intra-monthly competitive solicitation processes, into which resource scheduling coordinators may offer their capacity to the CAISO at prices up to a soft offer cap, currently set at $6.31/kw-month. Any offers above the soft offer cap must be cost-justified at FERC to recover up to a resource-specific cost of service rate. Since 2016, the CPM price has been determined by a monthly and intra-monthly Competitive Solicitation Process (CSP). The CPM tariff includes a soft offer cap calculated by adding a 20 percent premium to the levelized going-forward fixed costs of a reference resource (mid-cost 550 MW combined cycle with duct firing). From 2016 to present, the price of the CPM soft offer cap was $6.31/ kW-month. 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.[31] CAISO began an initiative to enhance the Capacity Procurement Mechanism in 2023.[32]

The CPM Enhancements stakeholder initiative consists of at least two tracks. Track 1 addressed CPM operational improvements, including changes to help the CAISO take greater advantage of uncontracted capacity in a specific calendar month. The CAISO Board of Governors approved the track 1 enhancements in March 2023. In track 2, CAISO staff propose to increase the CPM soft offer cap from $6.31/kw-month to $7.34/kw-month. This proposed increase is based on the following three justifications: (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; (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

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

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

offer cap to FERC on February 9, 2024.[33] The updated CPM soft offer cap is expected to be effective in the summer of 2024.

Table 13 shows CAISO's CPM designations for 2022.

Table 13. CAISO CPM Designations for 2022

Resource ID	MW	CPM Type	Term (days)	Start Date	End Date	Est. Cap. Cost /kW-mth	Total Cost
ELCAJN_6_UNITA1	19	Exceptional Dispatch (ED)	60	8/31/2022	10/30/2022	6.31	$1,140,000.00
PALOMR_2_PL1X3	64.37	Exceptional Dispatch (ED)	30	9/1/2022	10/1/2022	6.31	$1,931,100.00
MRCHNT_2_PL1X3	36.4	Exceptional Dispatch (ED)	30	9/1/2022	10/1/2022	6.31	$1,092,000.00

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 perform for all LSEs, either by statute or CPUC decision.

4.4.1 System Reliability Resources

D.06-07-029 adopted a process known as the Cost Allocation Mechanism, or CAM, which allows the CPUC to designate IOUs to procure new generation for system reliability within an IOU's distribution service territory. Under CAM, all related costs and benefits are allocated to all benefiting customers, including bundled utility customers, direct access customers, and customers of community choice aggregators. The LSEs serving these customers are proportionately allocated the capacity in each service territory, which is applied towards meeting LSEs' RA requirements. The LSEs receiving a portion of the CAM capacity pay only for the net cost of the capacity, which

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

is 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 or not elect to use CAM for new generation resources. In addition, the decision permitted CAM for utility-owned generation and allowed CAM to match the duration of the contract for the resource.

Table 14 provides the scheduling resource ID, the contract dates that the CAM was approved to cover, the authorized IOU, and August NQC values for all 2022 CAM resources. The list 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 2022

`	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
AES ES Alamitos, LLC	3/1/2021	12/31/2040	SCE	100
ALAMIT_2_PL1X3	6/1/2020	5/31/2040	SCE	674.7
BARRE_6_PEAKER	7/19/2007	UOG	SCE	47
CARLS1_2_CARCT1	12/1/2018	9/30/2038	SDG&E	422
CARLS2_1_CARCT1	12/1/2018	9/30/2038	SDG&E	105.50
CENTER_6_PEAKER	7/20/2007	UOG	SCE	47.11
CHINO_2_APEBT1	12/31/2016	12/30/2026	SCE	20
COCOPP_2_CTG1	5/1/2013	4/30/2023	PG&E	192.29
COCOPP_2_CTG2	5/1/2013	4/30/2023	PG&E	191.53
COCOPP_2_CTG3	5/1/2013	4/30/2023	PG&E	190.77
COCOPP_2_CTG4	5/1/2013	4/30/2023	PG&E	192.12
ELCAJN_6_EB1BT1	2/21/2017	12/30/2099	SDG&E	12
ELKHIL_2_PL1X3	1/1/2021	1/1/2024	SCE	100
ELSEGN_2_UN1011	8/1/2013	7/31/2023	SCE	263
ELSEGN_2_UN2021	8/1/2013	7/31/2023	SCE	263.68
ESCNDO_6_EB1BT1	3/6/2017	12/30/2099	SDG&E	20
ESCNDO_6_EB2BT2	3/6/2017	12/30/2099	SDG&E	20
ESCNDO_6_EB3BT3	3/6/2017	12/30/2099	SDG&E	20.00
ESCNDO_6_PL1X2	5/1/2014	12/31/2039	SDG&E	48.71
ETIWND_6_GRPLND	7/17/2007	UOG	SCE	47.39
HNTGBH_2_PL1X3	5/1/2020	4/30/2040	SCE	673.8
Miramar Energy Storage	6/1/2021	NA	SDG&E	30

`	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
MIRLOM_2_MLBBTA	7/1/2017	6/30/2027	SCE	10
MIRLOM_2_MLBBTB	7/1/2017	6/30/2027	SCE	10
MIRLOM_6_PEAKER	7/19/2007	UOG	SCE	46
MNDALY_6_MCGRTH	8/1/2012	UOG	SCE	47.2
OhmConnect, Inc.	1/1/2019	12/31/2024	SDG&E	4.5
Orni 34 LLC	7/1/2021	4/30/2041	SCE	10
PIOPIC_2_CTG1	6/1/2017	12/31/2037	SDG&E	111.3
PIOPIC_2_CTG2	6/1/2017	12/31/2037	SDG&E	112.7
PIOPIC_2_CTG3	6/1/2017	12/31/2037	SDG&E	112
SANTGO_2_MABBT1	10/1/2017	12/31/2026	SCE	2
SCE_1_PDR P173, P34; SCEW_2_PDR P160, P161, P162, P163, P164, P169.	3/1/2020	2/28/2030	SCE	15
SCEC_1_PDRP21, PDRP22, PDRP60, PDRP85, PDRP86, PDRP87, PDRP88; SCEW_2_PDRP89, PDRP90, PDRP91	12/1/2016	4/30/2027	SCE	20
SCEW_2_PDRP03	11/1/2017	4/29/2028	SCE	5
SCEW_2_PDRP09, PDRP10	2/1/2018	7/31/2028	SCE	5
SCEW_2_PDRP22, PDRP114, PDRP115, PDRP124, PDRP158, PDRP159, PDRP167, PDRP172	4/1/2019	3/31/2029	SCE	25
SENTNL_2_CTG1	8/1/2013	7/31/2023	SCE	103.76
SENTNL_2_CTG2	8/1/2013	7/31/2023	SCE	95.34
SENTNL_2_CTG3	8/1/2013	7/31/2023	SCE	96.85
SENTNL_2_CTG4	8/1/2013	7/31/2023	SCE	102.47
SENTNL_2_CTG5	8/1/2013	7/31/2023	SCE	103.81
SENTNL_2_CTG6	8/1/2013	7/31/2023	SCE	100.99
SENTNL_2_CTG7	8/1/2013	7/31/2023	SCE	97.06
SENTNL_2_CTG8	8/1/2013	7/31/2023	SCE	101.8
Silverstrand Grid, LLC	7/1/2021	12/31/2040	SCE	11
STANTN_2_STAGT1	7/1/2020	6/30/2040	SCE	49
STANTN_2_STAGT2	7/1/2020	6/30/2040	SCE	49
Strata Saticoy, LLC	6/1/2021	3/31/2041	SCE	100
VESTAL_2_WELLHD	1/16/2013	1/15/2023	SCE	49
VISTRA	6/1/2021	5/31/2041	PG&E	300
WALCRK_2_CTG1	6/1/2013	5/31/2023	SCE	96.43

`	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
WALCRK_2_CTG2	6/1/2013	5/31/2023	SCE	96.91
WALCRK_2_CTG3	6/1/2013	5/31/2023	SCE	96.65
WALCRK_2_CTG4	6/1/2013	5/31/2023	SCE	96.49
WALCRK_2_CTG5	6/1/2013	5/31/2023	SCE	96.65

*NQC values are from August 2021. For resources that began after August 2021, the August 2021 NQC is provided. NQC values can change monthly and annually.

4.4.2 QF/CHP Resources

D.10-12-035[34] adopted a Settlement for Qualifying Facilities and Combined Heat and Power (QF/CHP Settlement). The Settlement established the CHP program, which aims to have IOUs procure a minimum of 3,000 MWs 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 lowered the GHG emissions reductions target to 2.72 million metric tons.

The Settlement also established a cost allocation mechanism to be used to share the benefits and costs associated with meeting the CHP and GHG goals.[35] The adopted cost allocation mechanism was almost identical to the mechanism adopted in the long-term procurement plan (LTPP) for reliability (D.06-07-029). The settlement allows for the net capacity costs of an approved CHP resource to be allocated to all benefiting customers, 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.[36] Table 15 below lists the CHP resources whose RA capacity was allocated as of 2022.

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

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

[36] 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."

Table 15. CHP Resources Allocated for CAM as of 2022

Scheduling Resource ID	CAM Start Date	CAM End Date	August NQC*	Authorized IOU
ARCOGN_2_UNITS	7/1/2015	6/30/2022	259.89	SCE
BDGRCK_1_UNITS	8/1/2014	7/31/2026	36.29	PG&E
BEARMT_1_UNIT	7/1/2014	6/30/2021	44	PG&E
CALPIN_1_AGNEW	5/1/2013	4/30/2022	28.56	PG&E
CHALK_1_UNIT	10/1/2014	7/31/2026	43.06	PG&E
CHARMN_2_PGONG	8/1/2020	12/31/2026	19.7	SCE
CHEVMN_2_UNITS	1/1/2016	12/31/2022	7.54	SCE
CHINO_6_CIMGEN	7/1/2018	3/11/2025	26.0	SCE
DEXZEL_1_UNIT	4/1/2016	3/30/2023	17.78	PG&E
DOUBLC_1_UNITS	4/1/2012	11/30/2020	49.5	PG&E
ETIWND_2_UNIT1	4/1/2016	3/30/2023	10.34	SCE
FRITO_1_LAY	6/1/2017	5/31/2021	0.08	PG&E
GRZZLY_1_BERKLY	6/1/2017	6/2/2022	9.90	PG&E
HINSON_6_CARBGN	6/1/2017	5/31/2021	28.85	SCE
HOLGAT_1_BORAX	6/1/2017	6/2/2022	12.56	SCE
KERNFT_1_UNITS	12/29/1987	8/31/2026	48.6	PG&E
KERNRG_1_UNITS	8/1/2017	7/31/2024	0.20	PG&E
LIVOAK_1_UNIT 1	5/1/2015	4/30/2022	42.5	PG&E
LMEC_1_PL1X3	1/1/2014	12/31/2021	135.00	SCE
MKTRCK_1_UNIT 1	4/1/2015	5/31/2018	42	PG&E
OMAR_2_UNIT 1	1/1/2014	12/31/2020	70.3	PG&E
OMAR_2_UNIT 2	1/1/2014	12/31/2020	71.24	PG&E
OMAR_2_UNIT 3	1/1/2014	12/31/2020	74.03	PG&E
OMAR_2_UNIT 4	1/1/2014	9/30/2020	81.44	PG&E
OROVIL_6_UNIT	1/1/2014	10/14/2020	7.50	PG&E
SAMPSN_6_KELCO1	4/12/2018	3/31/2020	0.85	SDG&E
SIERRA_1_UNITS	4/1/2012	11/30/2020	49.57	PG&E
SNCLRA_2_UNIT	7/1/2015	3/31/2020	27.5	SCE
SNCLRA_2_UNIT1	10/1/2019	9/30/2026	13.91	SCE
SNCLRA_6_PROCGN	1/1/2020	9/30/2026	22.0	SCE
STOILS_1_UNITS	11/1/2019	10/31/2026	5.14	PG&E
SUNSET_2_UNITS	7/10/2014	12/31/2050	218	PG&E
SYCAMR_2_UNIT 1	11/1/2019	10/31/2026	77.41	SCE
SYCAMR_2_UNIT 2	1/1/2014	12/31/2021	74	SCE
SYCAMR_2_UNIT 3	1/1/2014	12/31/2021	74	SCE
SYCAMR_2_UNIT 4	1/1/2014	12/31/2021	74	SCE

Scheduling Resource ID	CAM Start Date	CAM End Date	August NQC*	Authorized IOU
TANHIL_6_SOLART	12/1/2019	11/30/2026	9.92	PG&E
TENGEN_2_PL1X2	12/1/2019	11/30/2026	37.60	SCE
TIDWTR_2_UNITS	1/1/2020	12/30/2026	11.19	PG&E
UNVRSY_1_UNIT 1	8/1/2020	12/31/2026	34.03	SCE

*NQC values are from August 2022. If the unit was not CHP CAM in August 2021, 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 the IOUs to procure DR capacity from third party DR providers. Capacity procured through DRAM is allocated to all customers similarly to that of CAM and CHP resources. Table 16 lists the DRAM capacity procured by the IOUs for 2022.

Table 16. DRAM Capacity Allocated for CAM for 2022

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
Multiple	1/1/2022	12/31/2022	PG&E	80.90
Multiple	1/1/2022	12/31/2022	SCE	107.37
Multiple	1/1/2022	12/31/2022	SDG&E	9.92
TOTAL				**198.19**

*NQC values can vary by month.

Event-based DR resources are market-integrated and are also treated as RA credit. The costs for most DR programs are allocated through the IOU delivery charge, which means that these DR programs are paid for by bundled customers, direct access customers, and the customers of community choice aggregators. The exceptions are SCE's Smart Energy Program and rate-based programs such as SCE and PG&E's Critical Peak Pricing (CPP) programs. The RA credit associated with DR is based on capacity estimated using the CPUC-adopted Load Impact Protocols. The IOUs and third-party DR providers submit ex-ante load impact values associated with each market-integrated DR program on April 1st for the coming RA compliance year. Energy Division verifies 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. When the values are final, DR RA credits are posted on the CPUC's RA compliance website and then allocated to all LSEs for the coming compliance year.

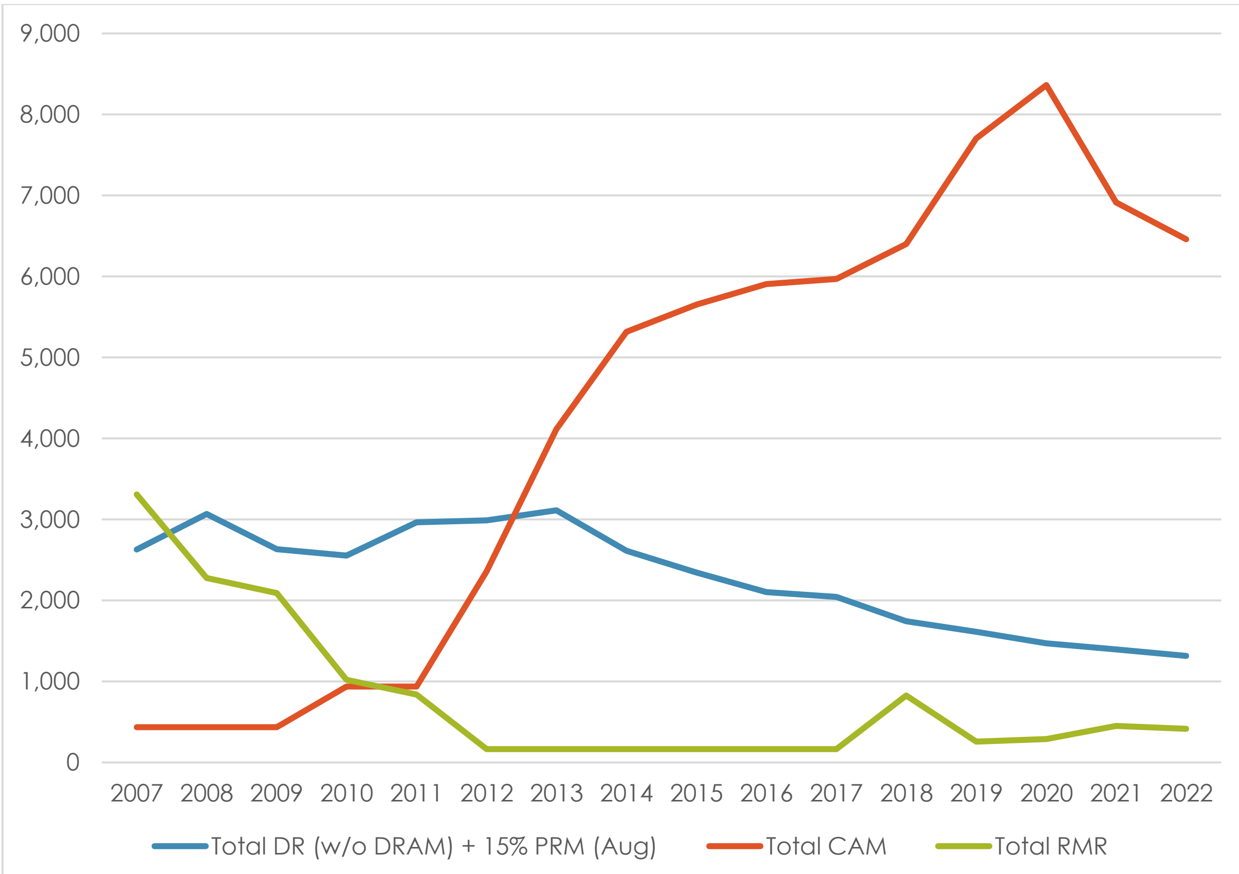
Table 17 and Figure 6 below illustrate the amounts and types of procurement credit that have been allocated since the beginning of the RA program.

Table 17. DR, CAM, and RMR Allocations for August, 2007-2022 (MW)

		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
DR	SCE		1,705	1,616	1,613	1,838	2,067	2,195	1583	1593	1480	1437	1215	1125	1031	977	1001
	PG&E		1018	912	846	888	744	783	933	689	565	566	488	448	424	402	301
	SDG&E		346	104	97	241	177	135	96	63	60	42	40	39	17	19	14
	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**
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
	PG&E						703	1,351	1,790	2,020	2,008	1,868	1,897	1,989	1,848	1,422	1,344
	SDG&E						130		49	49	49	399	413	975	980	1,012	1,018
	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**
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
	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**

Figure 6 reflects the decline in RMR units, but with a spike in 2018, and the increase in CAM units through 2020, declining in 2021 and 2022. DR RA credits have declined slightly since 2013. The total amount of capacity procured through DR, CAM, and RMR for August 2022 was 8,192 MW. This is about 18% of the total CPUC-jurisdictional LSE obligation for August 2022 (46,088 MW). In August 2022, total CAM procurement was 6,459 MW and RMR procurement dropped slightly from 450 MW in 2021 to 417 MW in 2022.

Figure 6. RA Procurement Credit Allocation, 2007 – 2022 (RMR, August DR, and August CAM)



5 NET QUALIFYING CAPACITY

Qualifying Capacity (QC) represents a resource's maximum capacity eligible to be counted towards meeting the CPUC's RA Requirements prior to an assessment of its deliverability. The CPUC adopted QC counting conventions, which are computed based on the applicable resource type, in D.10-06-036[37] and has updated counting methodologies in subsequent decisions. The applicable data sets and data conventions are contained in the most recent adopted QC methodology manual.[38]

The QC methodology varies by resource type:

- The QC value of dispatchable resources is based on the most recent maximum capability (Pmax) test.
- Non-dispatchable hydro and geothermal resources receive QC values 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 QC values are based on effective load carrying capability (ELCC) modeling.

The CPUC executes a subpoena for settlement quality meter and bidding data from the CAISO and performs QC calculations for non-dispatchable resources annually. ELCC values are periodically updated.

After the QC values are calculated, the CAISO conducts a deliverability assessment to produce the annual Net Qualifying Capacity (NQC) value of each resource. When the QC for a resource is greater than the resource's deliverable capacity, the NQC is adjusted to the deliverable capacity value. 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.

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

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

After the CAISO has completed its deliverability study, it posts a draft NQC list and generators typically have three weeks to file comments with the CAISO and CPUC regarding the proposed NQC values. After the comment period, the values are updated, if needed, and a final NQC list is posted. This NQC list includes information on the local area, the zonal area, and the deliverability of each resource.

5.1 New Resources and Retirements in 2022

Overall, 2022 saw an increase in available capacity. A total of 3,200 MW of capacity (NQC) was brought onto the system in 2022 while just 47 MW of capacity was retired.

Table 18 lists the new facilities that came online in 2022 and Table 19 lists the retiring and mothballed facilities for 2022. 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 generators also have NQC values well below net dependable capacity, since their NQC is based on ELCC modeling. For example, in 2022, the net dependable capacity of new facilities was about 4,820 MW which was more than 1,600 MW over the assigned NQC values.

Table 18. New NQC Resources Online in 2022

Resource ID	Resource Name	Technology	NQC	Net Dependable Capacity
ALMASL_2_AL6BT6	Almasol 6 BES	Battery Storage	50	50
CENTPD_2_BMSSX2	Blythe Mesa Solar	Solar	21.01	223.6
GOLETA_6_TR2BM2	Tajiguas Biogas Engines	Biomass	#N/A[39]	1.99
ELKHRN_1_EESX3	Elkhorn Energy Storage	Battery Storage	182.5	182.5
HOOV_2_ANAPT	Hoover Power Plant	Hydro	570	40.39
SPRGVL_2_PORTPV	Porterville Tulare PV	Solar	0	3.5
EDWARD_2_E21SB1	EdSan 2 Edwards 1A	Hybrid	82.86	166
SLATE_2_SLASR5	Slate 5	Hybrid	12.62	26
TRNQLT_2_RETBT1	RE Tranquillity BESS	Battery Storage	72	72
DYERSM_6_DSWWD1	Dyer Summit Wind Repower	Wind	9.48	44.8

[39] Not currently on NQC List

BIGSKY_2_ASLBT2	Antelope Solar 2 Luna	Battery Storage	100	100
WISTER_2_WISSR1	Wister Solar	Solar	2.48	20
BLKDIA_2_BDEBT1	Black Diamond Energy Storage	Battery Storage	200	200
MIDSUN_1_PL1X2	North Midway Cogens 5A 5B	Natural Gas	#N/A[40]	9.6
SANBRN_2_ES1BT3	EdSan 1 Edwards 1	Hybrid	25.64	50.43
EDWARD_2_ES2BT3	EdSan 2	Hybrid	76.67	151
VALTNE_2_TBBBT1	Tropico Solar Big Beau	Hybrid	24.11	58
WILLMS_6_ARBBM1	Abel Road Bioenergy	Biomass	0.00	3
ARLNTN_2_AR1SR1	Arlington	Solar	4.48	100
BLM W_2_COSBT1	Coso Battery Storage	Battery Storage	60	60
ENERSJ_5_ESJWD2	Energia Sierra Juarez Wind 2	Wind	11.43	105
SPRGVL_2_EXETPV	Exeter Tulare PV	Solar	0	3.5
RECTOR_2_IVANPV	Ivanhoe Tulare PV	Solar	0	3.5
SPRGVL_2_LINDPV	Lindsay Tulare PV	Solar	0	4
BIGSKY_2_AS2BT1	Antelope Solar 2 LAB	Battery Storage	127	127
JAVASR_1_JAVSR1	Java Solar	Solar	1.67	13.5
CASADB_1_CD4GT1	Casa Diablo 4	Geothermal	31	40.7
SUNCAT_2_A2ABT2	Arlington Solar Unit 2A BESS	Battery Storage	132	132
RATSKE_2_RBSSB1	Rabbitbrush Solar 1	Hybrid	14.49	60
ENERSJ_2_WIND	ESJ Wind Energy	Wind	16.44	151
GARLND_2_GARBT1	Garland B BESS	Battery Storage	88	88
BGSKYN_2_ASSR1B	Antelope Solar 1B	Solar	1.89	17
DREWSR_2_BHSSR1	Blue Hornet Solar	Solar	12.40	100
SANBRN_2_EESSB2	Edsan 2 Edwards Sanborn E1B	Hybrid	16.12	166
HERDLN_6_BYHSR1	Byron Highway Solar	Solar	0	5
VESTAL_2_TS5SR1	Tulare Solar 5	Solar	6.92	55.83
CRIMSN_2_CRMBT2	Crimson 2	Battery Storage	150	150
SLATE_2_SLASR2	SLATE_2	Hybrid	55.24	93
MTWIND_1_MVPWD1	Mountain View Power Project I Repower	Wind	7.25	66.6
ARLNTN_2_ASUSR1	Arlington Solar Unit 1	Solar	9.65	131
CENTPD_2_BMSX2	Blythe Mesa Solar 2 BESS	Battery Storage	112	112

[40] Not currently in NQC List

CRIMSN_2_CRMBT1	Crimson	Battery Storage	200	200
SUNCAT_2_A1ABT1	Arlington Solar Unit 1A BESS	Battery Storage	47	47
SANBRN_2_ES2SB3	EdSan 2 Sanborn 3	Hybrid	21.01	42
KEARNY_6_SESBT2	Kearny South Energy Storage	Battery Storage	10	10
SIGHEB_6_HE2SCEDYN	Heber 2	Geothermal	28	28
LECONT_2_LESBT1	LeConte Energy Storage	Battery Storage	40	125
DSRTSN_2_DS2X2	Desert Sunlight PV II Storage	Battery Storage	230	230
VALTNE_2_TRSBT1	Tropico Solar	Hybrid	29.36	70
KEARNY_6_NESBT1	Kearny North Energy Storage	Battery Storage	10	10
OASIS_6_LPPSR1	Lancaster Psomas PV	Solar	#N/A[41]	3
JOANEC_2_STABT2	Santa Ana Storage 2	Battery Storage	20	20
ATHOS_5_AP1X2	Athos Power Plant	Solar	31	250
SLATE_2_SLASR3	SLATE_3	Hybrid	40.1	67.5
EDWARD_2_ESSSB1	Sanborn Solar 2 Edwards 5	Hybrid	7.44	116
PEASE_1_TBEBT1	Tierra Buena Energy Storage	Battery Storage	5	6
SUNCAT_2_A1BBT1	Arlington Solar Unit 1B BESS	Battery Storage	63	63
SLATE_2_SLASR4	SLATE_4	Hybrid	54.81	63
PUTHCR_1_PCNSB1	Putah Creek Solar Farm North	Hybrid	3	3
DRACKR_2_DSUBT4	Dracker Solar Unit 4 BESS	Battery Storage	47	47
RATSKE_2_RBSSB2	Rabbitbrush Solar 2	Hybrid	9.66	40
EDWARD_2_ESSSB2	Sanborn Solar 2	Hybrid	16.37	132
GRNLF1_1_PL1X2	Greenleaf 1	Natural Gas	#N/A[42]	60
		Total	**3200.1**	**4819.94**

[41] Not currently in NQC List

[42] Not currently in NQC List

Source: 2021-2022 NQC lists posted to the CAISO website.[43]

Table 19. Resources Retired in 2022

Resource ID	Resource Name	Technology	NQC
SPANSH_6_FBEHY1	Five Bears Hydro, LLC.	Hydro	1.79
GARNET_1_UNITS	Garnet Green Power Project Aggregate	Wind	3.47
HINSON_6_CARBGN	BP WILMINGTON CALCINER	Steam Turbine	29.64
CPSTNO_7_PRMADS	Prima Deshecha (Capistrano)	Reciprocating Engine	5.11
MONLTH_6_BATTRY	Tehachapi storage project	Storage	5.4
MIRLOM_2_ONTARO	Ontario RT Solar	Solar	1.49
PSWEET_7_QFUNTS	PSWEET_7_QFUNTS	Other	0
		Total	**46.9**

Source: CAISO Announced Retirement and Mothball list.[44]

The once-through-cooling (OTC) units that were expected to retire in 2020 were extended to the end of 2023 for reliability reasons. The Statewide Advisory Committee on Cooling Intake Structures (SACCWIS) recommended an extension of Alamitos Units 3, 4, and 5 for three years until December 31, 2023, an extension of Huntington Beach Unit 2 for three years until December 31, 2023, an extension of Ormond Beach Units 1 and 2 for three years until December 31, 2023, and an extension of Redondo Beach Units 5, 6, and 8 for one year until December 31, 2021.[45]

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

[44] http://www.caiso.com/Documents/AnnouncedRetirementAndMothballList.xlsx

[45] SACCWIS report, January 23, 2020, p.12

5.2 Aggregate NQC Values 2016 through 2022

Table 20 shows aggregate NQC values from the CAISO NQC lists for 2016 through 2022.[46] The total 2022 NQC (as reported on the CAISO NQC list) increased by 2,120 MW from the 2021 NQC list.

Table 20. Final NQC Values for 2016-2022

Year	Total NQC (MW)	Total Number of Scheduling Resource IDs	Net NQC Change (MW)	Net Gain in CAISO IDs on List
2016	53,173	972		
2017	55,871	1,097	2,698	125
2018	49,389	1,198	-6,482	101
2019	48,429	1,684	-960	486
2020	48,989	1,961	560	277
2021	47,244	I1,718	-1745	-243
2022	49,364	1,792	2120	74
2016-22			**-3,809**	**820**

Source: NQC lists from 2016 through 2022.[47]

[46] 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.

[47] 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 final NQC lists of the year, prepared in the fall.

6 COMPLIANCE WITH RA REQUIREMENTS

6.1 Overview of the RA Filing Process

The RA filing process requires compliance documents to be submitted by the LSEs, load forecasting to be performed by the CEC, supply plan validation to be performed by the CAISO, and DR, local RA, CAM, and RMR allocations to be performed by Energy Division. Additionally, the Energy Division evaluates each RA filing submission and continually works with LSEs to improve the RA administration process.

As in previous years, Energy Division hosted a workshop to discuss general compliance rules as well as to highlight changes in procedures and filing rules new to the 2022 compliance year. The workshop, RA guide, and templates were designed to assist LSEs in demonstrating compliance with the RA program.

The final 2022 filing guide and templates were made available to LSEs in October 2021.[48] Changes were made to implement the new RA rules discussed in section 2.2. 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 following comprehensive RA program procedures:

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

A crucial step in this process relies on CAISO collection and organization of supply plans submitted by scheduling coordinators for generators. Energy Division verifies

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

compliance, sends deficiency and correction notices, and approves compliant filings (noncompliant filings are discussed in the Subsections 6.3 and 6.4).

6.3 Enforcement and Compliance

The essence of the RA program is mandatory LSE acquisition of capacity to meet load and reserve requirements. The short timeframes in which the CPUC and CAISO staff must verify that adequate capacity has been procured and, if necessary, complete backstop procurement requires filings to arrive on time and to be accurate. Non-compliance occurs if an LSE files with a procurement deficiency (i.e., insufficient capacity to meet its RA obligations), does not file at all, files late, or does not file in the manner required. These types of non-compliance generally lead to enforcement actions or citations by the CPUC. The CAISO does not typically need to engage in backstop procurement for collective and CPUC-jurisdictional LSE procurement deficiencies, although this might be expected to occur more frequently if the CPUC did not strictly enforce RA program compliance.

6.4 Enforcement Actions in the 2012 through 2022 Compliance Years

Pursuant to CPUC Resolution E-4195[49], D.11-06-022, and D.14-06-050, Energy Division refers potential violations to the CPUC's Consumer Protection and Enforcement Division (CPED), which pursues enforcement cases related to the RA program on behalf of the CPUC. The penalty structure described in Section 2.2 is used to enforce the RA program. Beginning in 2023, the Commission can now publish the following citation information on its RA citation website. They will be published no earlier than October 1 of the compliance year. The type of RA deficiency, month of deficiency, deficiency amount (MW), and any points accrued can now be published.[50]

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

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

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

citations and penalties public on the CPUC's RA Program website, including linking 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 has 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 can have sufficient information to understand and address RA program violations.[51] 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."[52]

Types of Deficiencies and Citations

As shown in Table 21, CPUC LSEs are required to provide information to demonstrate compliance with Resource Adequacy (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.

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	$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,		

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

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

the date of notification by the Energy Division	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)[53]	$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.

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.

An RA capacity deficient LSE may be cited by the CPUC (usually after some time delay), but it has avoided paying the actual cost of the RA capacity. The RA program penalty is meant to be a deterrent, so even with the application of a penalty, a deficient LSE may be leaning on other LSEs' procurement or relying on various backstop

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

procurement mechanisms, and such mechanisms do not usually have a method to charge specifically an RA-deficient LSE.

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. The RA Program Citation Database may contain multiple rows or violations for each assigned citation number.

Table 22 summarizes citations issued and enforcement actions taken by the CPUC since 2010. From 2010 through 2023, the CPUC issued 136 citations for 493 program violations and took no enforcement action. Table 22 reflects RA program citations from 2010 to 2023 by LSE name and type. The number of LSEs is currently 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 Community Choice Aggregators (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

	Sum of Citation Amount ($)		Count of Energy Citation Number	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	1642.98
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	1290.22
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**	**6517.44**
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**	**1462.02**
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**	**7979.46**

As reflected in Table 23, since 2010 there have been three 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.

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

		Sum of Citation Amount ($)	Count of Energy Citation Number	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	1269.61
2022	$	8,720,474.80	11	17	998.46
2023	$	21,322,783.20	18	34	2282.43
CCA Total	**$**	**54,035,332.30**	**55**	**94**	**6517.44**
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**	**1462.02**
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**	**7979.46**

Table 24 shows that in 2022, eighteen citations were issued for penalties of $10,977,140.[54] 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, and changes in resource counting methodologies.

Table 24. Citations Issued for the RA Program from 2012-2022

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, Liberty Power (2)	$26,500
2014	1	3 Phases	$5,000
2015	6	3 Phases (2), Commerce Energy (2), EDF Industrial, Glacial Energy	$38,000
2016	3	Tiger Natural Gas, Glacial Energy, Shell Energy	$13,500

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

Compliance Year	Citations Issued	LSEs Cited	Citation Penalties
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
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
Total	**120**		**$39,507,556**

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

7 APPENDIX

7.1 2022 List of CPUC Jurisdictional LSEs

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

32. Sonoma Clean Power Authority
33. Silicon Valley Clean Energy Authority
34. The Regents of the University of California
35. Valley Clean Energy Alliance
36. Desert Community Energy
37. San Diego Community Energy
38. Clean Energy Alliance