2020 RESOURCE ADEQUACY REPORT

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CALIFORNIA PUBLIC UTILITIES COMMISSION
ENERGY DIVISION

A digital copy of this report can be found at:

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

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LIST OF ACRONYMS

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

EXECUTIVE SUMMARY

The Resource Adequacy (RA) program was developed in response to the 2001 California energy crisis. 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 15 percent reserve margin. 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 RA program experience during the 2020 RA compliance year. While this report does not make explicit policy recommendations, it provides information relevant to the currently open RA rulemaking and ongoing implementation of the RA program in California.

A key to establishing accurate RA procurement targets is accurate demand forecasts. The California Energy Commission (CEC) assesses the reasonableness of LSE-submitted forecasts, then makes demand side management adjustments, plausibility adjustments, and a prorated adjustment to each LSE's forecast to ensure that the total for all forecasts is within 1 percent of the CEC's overall service area forecast. The overall CEC-adjusted forecast for CPUC-jurisdictional LSEs had an expected peak in August, 2020, of 40,416 MW, which represented a 2.2% percent decrease from the peak forecast of 41,336 MW for 2019. The plausibility adjustments as a percentage of each month's aggregated year-ahead forecast ranged from 1.93 percent to 5.89 percent.

Each October, the RA program requires LSEs to make annual system, local, and flexible compliance showings for the coming year. For the system showing, LSEs must demonstrate that they have procured 90 percent of their system RA obligation for the five summer months. For the local showing, LSEs must demonstrate that they have procured 100 percent of their local RA obligation for all twelve months. LSEs are also

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

required to demonstrate that they have procured 90 percent of their flexible RA obligation for all twelve months. In addition to the annual RA requirement, the RA program has monthly requirements. On a month-ahead basis, LSEs must demonstrate they have procured 100 percent of their monthly system and flexible RA obligations. Additionally, from July through December, the LSEs must demonstrate on a monthly basis that they have met 100 percent of their local obligation which is revised to reflect load migration.

In 2020, CPUC-jurisdictional LSEs met their peak load RA obligations. The 2020 peak demand (for CPUC-jurisdictional LSEs, after net load migration adjustments) was forecasted to occur in August, 2020, at 40,571 MW. The RA obligation for August, including a 15 percent planning reserve margin, totaled 46,657 MW and LSEs collectively procured 48,099 MW.

The peak demand in CAISO for 2020 of 46,974 MW, which includes CPUC-jurisdictional and non-CPUC jurisdictional LSEs, occurred on August 18, 2020, during the hour between 3 and 4 pm.[2] The 2020 CAISO peak was higher than the 2019 peak of 44,148 MW. About 90 percent of 2020 actual peak load, or about 42,277 MW, could be attributed to CPUC-jurisdictional LSEs. Despite meeting the collective RA requirements at the peak hour of the peak day, CAISO experienced rotating outages on August 14 and 15, 2020, the causes of which are discussed in the Final Root Cause Analysis prepared by the CAISO, CPUC and CEC[3] and in the Report on System and Market Conditions, Issues and Performance prepared by CAISO's Department of Market Monitoring.[4]

CPUC-jurisdictional LSEs collectively met all local RA requirements during the 2020 compliance year. The 2020 local RA procurement obligations for CPUC-jurisdictional

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[2] This peak is the average used over the hour. The technical peak minute is recorded by CAISO as 47,121 MW at 15:57. See http://www.caiso.com/documents/californiaisopeakloadhistory.pdf. When used in this report, the peak will refer to the peak hour measurement.

[3] "Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave," January 13, 2021, available at Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf (caiso.com).

[4] "Report on System Market Conditions, Issues and Performance: August and September 2020," November 24, 2020, available at http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf.

LSEs totaled 20,967 MW. LSEs and CAISO procured a monthly minimum of 29,359 MW. Physical resources, cost allocation mechanism (CAM) resources, reliability must-run (RMR) resources, and demand response (DR) resources contributed to this total.

In 2020, total committed RA resources ranged from 33,095 MW in March to 48,099 MW in August. Bilateral contracting made up most of forward capacity procurement. However, CAM, RMR, and DR procurement, the costs and benefits of which are passed through to all customers by Transmission Access Charge (TAC) area, also contributed to meeting RA obligations. Between 85 and 93 percent of all committed RA capacity, including CAM, was procured by LSEs from unit-specific physical resources within the CAISO control area. Unspecified Imports accounted for 2 to 12 percent of capacity, and DR made up 3 to 4 percent. CAM and RMR resources consisted of 18 to 25 percent of total RA capacity procured.

Last year saw the margin between the weighted prices of system and local decrease, and that trend continued in 2020. The weighted average price of local RA is $4.96/kW-month compared to $4.75/kW-month for system RA capacity. Local RA prices have also increased-- 2020 weighted average prices for local areas range from $3.86/kW-month in the Bay Area to $7.70/kW-month in Stockton, while 85th percentile prices ranged from $5.50/kW-month for unspecified PG&E local capacity to $9.25/kW-month in Sierra. These are significant increases over prices reported in prior years. For flexible capacity, prices are not higher than those for system capacity. The 2020 weighted average price for flexible capacity is $4.65/kW-month while it is $4.81/kW-month for non-flexible system capacity.

Because the RA program requires LSEs to acquire capacity to meet load and reserve requirements, the CPUC issues citations or initiates enforcement actions when LSEs do not fully comply with RA program rules.[5] In total, the CPUC issued twenty citations for violations related to compliance year 2020 for a total of $2,707,435.

[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).

1 INTRODUCTION

The Resource Adequacy (RA) program was developed in response to the 2001 California energy crisis. The program is designed to ensure that California Public Utilities Commission (CPUC) jurisdictional Load Serving Entities (LSEs)[6] have sufficient capacity to meet their peak load with a 15 percent reserve margin. The RA program began implementation in 2006 and is intended to provide the energy market with adequate 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, produced annually on Staff's own motion, provides a review of the CPUC's RA program and summarizes RA program experience during the 2020 RA compliance year. It is designed to shed light on the current state of the RA program. While this report does not make explicit policy recommendations, it provides information relevant to the currently open RA rulemaking and ongoing implementation of the RA program in California.

1.1 Resource Adequacy Program Requirements

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.

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

To establish the year-ahead load forecast, the CEC first calculates each LSE's specific monthly coincidence factors[7] using the historic hourly load data filed by each LSE. 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 percent of the CEC service area forecast. If the aggregated LSE forecasts diverge more than 1 percent from the CEC's monthly weather normalized forecasts, the CEC makes a pro-rata adjustment to reduce the divergence to below 1 percent.

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 were calculated using the load shares for September 2020 of the projected year ahead. The forecasts and allocations together determine both the annual and monthly system RA obligations.

1.2 Changes to the Resource Adequacy Program for 2020

In D. 19-02-022, the CPUC made the following changes to the RA program:

- Multi-year local Resource Adequacy requirements were adopted for individual load serving entities, with a minimum three-year forward duration.

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

- The minimum required percentage for local procurement in Years 1 and 2 was set at a 100% requirement. The minimum required percentage for local procurement in Year 3 was set at 50%.
- The local penalty and waiver process instituted on a one-year basis, pursuant to Decision (D.) 06-06-064 and D.07-06-029, was applied to the three-year forward requirement.
- The due date for flexible, system, and three-year ahead local showings was set as October 31.
- The "Pacific Gas and Electric Company (PG&E) Other" local area was disaggregated to the local capacity area.

In D.19-06-026, the CPUC made the following changes to the RA program:

- The local RA waiver trigger price of $40/kW-year, adopted in Decision 06-06-064, was updated to the annualized value of the 85th percentile of the monthly local RA prices for South of Path 26, or $51/kW-year.
- The local RA penalty price of $3.33/kW-month was raised to the equivalent value of the newly-adopted local RA trigger price, or $4.25/kW-month.
- Required that Local RA waiver requests be submitted via a Tier 2 Advice Letter to the CPUC with accompanying service to the service list of the RA proceeding, due on the same date as other year ahead or month ahead filing components.
- Clarified that if a load-serving entity (LSE) incurs both flexible and system RA deficiencies, the penalty shall be based on the following:

    a. Where an LSE incurs equivalent flexible and system RA deficiencies, the system RA penalty price shall apply.

    b. Where an LSE incurs a flexible RA deficiency that exceeds its system RA deficiency, the system RA penalty price shall apply to the megawatt amount of the system deficiency and the flexible RA penalty price shall apply to the flexible deficiency megawatt amount that exceeds the system deficiency.
- Clarified that load migration shall be the only allowable reason for differences between initial and final year ahead load forecasts.
- "Load migration" was defined, for the purposes of the Resource Adequacy program, as load effects that:

a. Result from one or more customers' retail electric service transferring directly from one load-serving entity (LSE) to another LSE in the same Transmission Access Charge area; and

b. An LSE cannot reasonably predict and include in an implementation plan or in an initial year ahead load forecast.

- Permitted that LSEs' final load forecasts may need to be modified with new or updated customer opt-out data until the full implementation of the adopted data sharing requirements in D.19-06-026. Thus, on an interim basis until the year ahead process for the 2022 compliance year, LSEs may incorporate changes resulting from the receipt of new or updated customer meter load data in their final year ahead forecasts.
- Adopted the Energy Division's proposal on conflict resolution between LSEs.
- Adopted the Energy Division's revised Effective Load Carrying Capacity (ELCC) analysis, effective beginning with 2020 Resource Adequacy compliance year.
- Eliminated the Path 26 constraint, adopted in Decision 07-06-029.

2 LOAD FORECAST AND RESOURCE ADEQUACY PROGRAM REQUIREMENTS

Section 2 describes the yearly and monthly load forecast process and the resulting system, local, and flexible RA requirements for CPUC-jurisdictional LSEs. It also details the types of resources used by LSEs to meet those requirements.

2.1 Yearly and Monthly Load Forecast Process

RA requirements for 2020 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 forecasts have been required starting in 2018.[8] The 2020 revised annual forecasts were due on August 16, 2019. These revised forecast values updated and informed the final year-ahead allocations, which were used in the year-ahead filing process. CPUC staff sent initial allocations to LSEs on July 26, 2019, and final allocations to LSEs on September 20, 2019.

LSEs file historical load information	**March 15, 2019**
LSEs file 2020 year-ahead load forecast	**April 19, 2019**
LSEs receive 2020 year-ahead RA obligations	**July 26, 2019**
Final date to file revised forecasts for 2020	**August 16, 2019**
LSEs receive revised 2020 RA obligations	**September 20, 2019**

The CPUC and CEC do not rely exclusively on year-ahead load forecasts because load migration can significantly affect LSE forecasts, particularly for small energy service providers (ESPs). During the compliance year, LSEs adjust their load forecasts on a monthly basis to account for load migration. This process is outlined in D.05-10-042.[9] As discussed in the RA Guide for the 2020 compliance year, LSEs must submit a revised

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

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

forecast prior to each compliance filing month.[10] These load forecast adjustments are solely for load migration between LSEs, not changing demographic or electrical conditions. Per D.10-06-036,[11] 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 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 2.3.

2.1.1 Yearly Load Forecast Results

Table 1 shows the aggregate LSE submissions for 2020 and the adjustments that were made by the CEC across the three IOU service areas.[12] 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 one percent 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 August 2020 of 40,416, which represented a 2.2 percent decrease from the peak forecast of 41,366 MW for September 2019.[13]

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

[11] Available at http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/119856.htm, Ordering Paragraph 6.

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

[13] The 2019 RA report can be found at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2019rareport-1.pdf.

Table 1. 2020 Aggregated Load Forecast Data (MW) - Results of Energy Commission Review and Adjustment to the 2020 Year-Ahead Load Forecast

Element	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Submitted LSE Forecast	28,120	27,485	26,836	27,917	30,284	35,415	39,330	39,679	39,544	33,128	28,295	28,553
Adjustment for Plausibility and Migrating Load	811	873	514	1,362	1,895	1,821	1,673	1,522	1,570	786	870	871
EE/DG/DR Adjustment	(323)	(316)	(305)	(306)	(371)	(372)	(441)	(411)	(399)	(298)	(313)	(292)
Pro Rata Adjustment	579	436	403	555	1,166	962	576	586	596	450	280	739
Non-Coincident Peak Demand	**29,187**	**28,479**	**27,448**	**29,528**	**32,974**	**37,827**	**41,138**	**41,377**	**41,310**	**34,067**	**29,133**	**29,871**
Coincidence Adjustment	(789)	(823)	(746)	(1,038)	(828)	(1,060)	(1,101)	(962)	(938)	(978)	(958)	(767)
Final Load Forecast Used for Compliance	**28,399**	**27,656**	**26,702**	**28,490**	**32,146**	**36,767**	**40,037**	**40,416**	**40,372**	**33,089**	**28,175**	**29,104**

Source: CEC Staff.

2.1.2 Year-Ahead Plausibility Adjustments and Monthly Load Migration

Table 2 below presents the aggregate monthly plausibility adjustments for all LSEs from 2013 to 2020 and calculates the 2020 monthly plausibility adjustments as a percentage of the monthly year-ahead forecast for 2020.

In 2020, the CEC's plausibility adjustments increased the load forecast for all months. The CEC found that all but one LSE required adjustments to their load forecast. The 2020 monthly plausibility adjustments as a percentage of that month's aggregated year-ahead forecast ranged from 1.93 percent to 5.89 percent. 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, 2013-2020 (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
2020 Plaus. Adj./Load	2.86%	3.16%	1.93%	4.78%	5.89%	4.95%	4.18%	3.77%	3.89%	2.38%	3.09%	2.99%

Source: Year-ahead CEC load forecasts, 2013-2020.

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 2020. There were generally 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 0.96 percent for September 2020. On a megawatt basis, the net monthly load migration adjustments ranged from -39 to 386 MW.

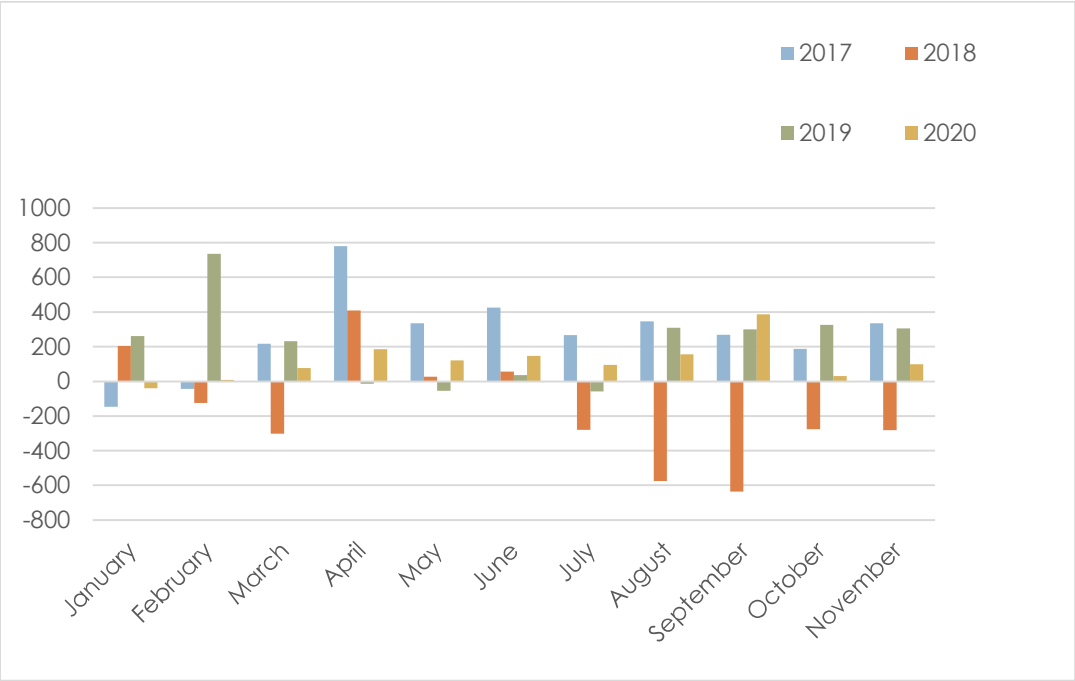
Table 3. Summary of Load Migration Adjustments in 2020 (MW)

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Final YA Load Forecast	28,399	27,656	26,702	28,490	32,146	36,767	40,037	40,416	40,372	33,089	28,175	29,104
Monthly Adjustments	(39)	9	76	185	121	147	95	156	386	31	98	167
Final Forecasts in Monthly RA Filings	28,359	27,664	26,778	28,675	32,268	36,914	40,132	40,571	40,758	33,120	28,273	29,271
Monthly Adjustments/ Final YA Load Forecast	-0.14%	0.03%	0.28%	0.65%	0.38%	0.40%	0.24%	0.38%	0.96%	0.09%	0.35%	0.57%

Source: Load forecast adjustments submitted to the CEC and CPUC in 2020.

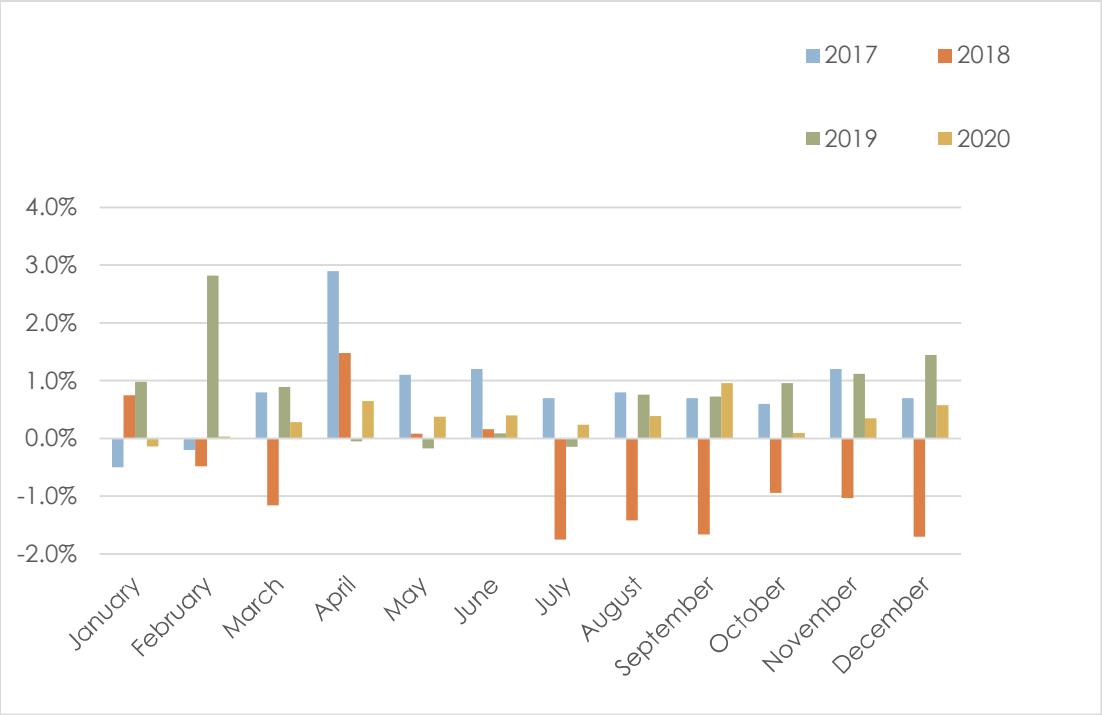
Net load migration should be close to zero, since it is defined as customers transferring directly from one LSE to another. Discrepancies in the adjustments made by LSEs gaining and losing customers, however, can cause overall load migration adjustments to deviate from zero. In recent years, the CPUC and CEC have worked to identify the reasons for these discrepancies and to encourage closer coordination between LSEs during forecast development. Figure 1 and Figure 2 illustrate the net monthly load migration between LSEs from 2017 through 2020. Load migration remained relatively low throughout this period, with monthly migration remaining below 800 MW (or 3 percent of total load).

Figure 1. Net Load Migration Adjustments per Month (MW), 2017-2020



Source: Monthly forecast adjustments submitted by LSEs, 2017-2020.

Figure 2. Net Load Migration as Percentage of Total Forecasted Load, 2017-2020



Source: Monthly forecast adjustments submitted by LSEs, 2017-2020.

2.2 System RA Requirements for CPUC-Jurisdictional LSEs

CPUC-jurisdictional LSEs met their collective system RA requirements for every month of 2020. The total MW of RA resources procured exceeded the total system Resource Adequacy Requirement (RAR) by 2.6 to 7.5 percent, depending on the month.[14] Table 4 shows the total CPUC-jurisdictional RA procurement for each month of 2020, broken down by physical resources within the CAISO's control area (including CAM resources), DR, capacity procurement mechanism (CPM), and 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 percent planning reserve margin (PRM). DR resources, including Demand Response Auction Mechanism (DRAM) resources, are also reported with the 15 percent PRM applied.

Table 4. 2020 RA Filing Summary - CPUC-jurisdictional Entities (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
RAR without DR, CAM, & RMR	32,613	31,814	30,795	32,976	37,108	42,451	46,152	46,657	46,872	38,088	32,514	33,662
CAM	7,413	7,400	7,397	7,231	7,880	8,753	8,850	8,363	8,371	8,252	8,294	8,245
Phys. Res. (w/ CAM)	31,676	30,793	30,219	31,775	34,495	39,923	41,652	41,013	39,196	34,106	30,749	32,010
Import (Resource Specific)	821	806	953	720	1,107	1,262	1,253	1,256	1,179	781	713	833
Import (Unspecified)	519	544	546	682	1,609	1,509	3,100	3,850	5,795	2,515	697	649
Total Imports	1,340	1,350	1,499	1,402	2,716	2,771	4,353	5,106	6,974	3,296	1,410	1,482

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

DR plus 15% PRM	967	1,032	1,039	1,131	1,323	1,668	1,684	1,719	1,665	1,497	1,210	1,106
RMR	165	165	165	148	148	148	148	192	192	192	192	192
Pref. LCR Credit	127	166	172	161	178	184	25	68	68	68	68	68
CPM	0	0	0	0	0	0	0	0	0	0	0	0
Total	34,276	33,505	33,095	34,617	38,860	44,694	47,862	48,099	48,096	39,159	33,630	34,859
Total/RAR	**105.1%**	**105.3%**	**107.5%**	**105.0%**	**104.7%**	**105.3%**	**103.7%**	**103.1%**	**102.6%**	**102.8%**	**103.4%**	**103.6%**

Source: LSE Monthly RA Filings.

In 2020, total committed RA resources ranged from 33,095 MW in March to 48,099 MW in August. Between 81 and 92 percent of all committed RA capacity (including CAM) was procured by LSEs from unit-specific physical resources within the CAISO control area. Unspecified Imports accounted for 2 to 12 percent of capacity, and DR made up 3 to 4 percent. CAM and RMR resources consisted of 18 to 25 percent of total RA capacity procured. These resources enabled CPUC-jurisdictional LSEs to meet between 105.3 and 102.6 percent of total procurement obligations in each summer month. The actual peak demand in CAISO of 46,974 MW, which includes CPUC-jurisdictional and non-CPUC jurisdictional LSEs, occurred on August 18, 2020, during the hour between 3 and 4 pm.[15] The 2020 CAISO peak was higher than the 2019 peak of 44,301 MW.[16] About 90 percent of 2020 actual peak load, or about 42,277 MW, could be attributed to CPUC-jurisdictional LSEs.

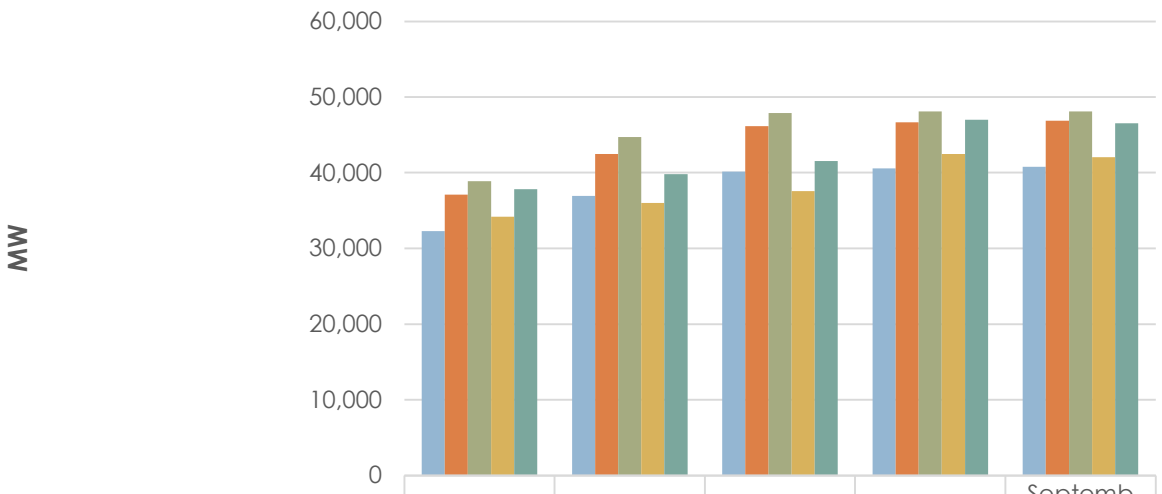
Figure 3 shows the 2020 total load forecast, procurement obligation (forecast plus PRM), and total committed RA capacity for CPUC-jurisdictional LSEs, compared with the CAISO-jurisdictional actual peak load. The difference between the forward commitment obligation and the total RA resources committed reflects the excess capacity committed to meet the monthly RA requirement. The CAISO jurisdictional

[15] This peak is the average used over the hour. The technical peak minute is recorded by CAISO as 47,121 MW at 15:57. When used in this report, the peak will refer to the peak hour measurement.

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

peak can be higher than CPUC RA obligations and total RA committed because it includes non-CPUC jurisdictional load.

Figure 3. 2020 CPUC Load Forecast, RA Requirements, Total RA Committed Resources, and Actual Peak Load For Summer Months



	May	June	July	August	September
Load Forecast (CPUC-juris.)	32,268	36,914	40,132	40,571	40,758
Forward Commitment Obligation	37,108	42,451	46,152	46,657	46,872
Total RA Resources Committed	38,860	44,694	47,862	48,099	48,096
Est. Peak Load (CPUC-juris.)	34,186	35,995	37,565	42,457	42,054
Actual Peak Load (CAISO)	37,823	39,824	41,561	46,974	46,528

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

2.3 Rotating Outages of 2020

CAISO experienced rotating outages on August 14 and 15, 2020. Following these emergency events, Governor Gavin Newsom requested that, after taking actions to minimize further outages, the CAISO, the CPUC, and the CEC report on the root causes of the events leading to the August outages. The Preliminary Analysis was released on October 6, 2020, followed by the Final Root Cause Analysis on January 13, 2021.[17] In

[17] "Report on System Market Conditions, Issues and Performance: August and September 2020," November 24, 2020, available at http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf.

addition, CAISO's Department of Market Monitoring also released a report addressing issues in August and September 2020.[18] This Final Root Cause Analysis finds that the three major causal factors contributing to the August outages were related to extreme weather conditions, resource adequacy and planning processes, and market practices. In summary, these factors were the following:

1. The climate change-induced extreme heat wave across the western United States resulted in demand for electricity exceeding existing electricity resource adequacy (RA) and planning targets.

2. In transitioning to a reliable, clean, and affordable resource mix, resource planning targets have not kept pace to ensure sufficient resources that can be relied upon to meet demand in the early evening hours. This made balancing demand and supply more challenging during the extreme heat wave.

3. Some practices in the day-ahead energy market exacerbated the supply challenges under highly stressed conditions.

Many of these issues continue to be discussed and addressed in proceeding at the CPUC, stakeholder processes at the CAISO and various dockets at the CEC.

2.4 Local RA Program – CPUC-Jurisdictional LSEs

The CPUC requires LSEs 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. 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.[19] The

[18] "Report on System Market Conditions, Issues and Performance: August and September 2020," November 24, 2020, available at http://www.caiso.com/Documents/ReportonMarketConditionsIssuesandPerformanceAugustandSeptember2020-Nov242020.pdf.

[19] Local Capacity Requirement (LCR) studies and materials for 2020 and previous years are posted atCalifornia ISO - Reliability Requirements (caiso.com).

results of the analysis are adopted in the annual 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.19-06-026, the CPUC adopted the 2020 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). Unlike previous years, local areas were not aggregated for RA compliance. Additionally, D.19-06-026 adopted multi-year local RA requirements, discussed below.

2.4.1 Year-Ahead Local RA Procurement

Table 5 summarizes the 2020 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. Procurement exceeded local RA obligations in five of the ten local areas by 0.9 to 11 percent. The "Pacific Gas and Electric Company (PG&E) Other" local area was disaggregated to the local capacity area pursuant to D. 19-02-022.

Table 5. Local RA Procurement in 2020, CPUC-Jurisdictional LSEs

Local Areas in 2020	Total LCR	CPUC-Jurisdictional Local RAR	Minimum Physical Resources per Month	Local RMR & CAM Credit	Local DR	Minimum Procurement/ Local RAR
LA Basin	7,364	6,503	6,741	3,770	645	103.7%
Big Creek/Ventura	2,410	1,876	2,082	1,291	137	111.0%
San Diego-IV	3,895	3,896	3,576	954	15	91.8%
Greater Bay Area	4,550	3,804	3,838	1,001	100	100.9%
Fresno	1,694	1,524	1,692	0	38	111.0%
Sierra	1,764	1,587	1,480	8	28	93.3%
Stockton	629	567	489	0	23	86.2%
Kern	465	422	421	309	84	99.7%
Humboldt	130	121	125	0	0	103.2%
NCNB	742	667	656	0	5	98.2%
Totals	23,643	20,967	21,098	7,333	1,076	100.6%

Source: 2020 Year Ahead RA filings.

2.4.2 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.

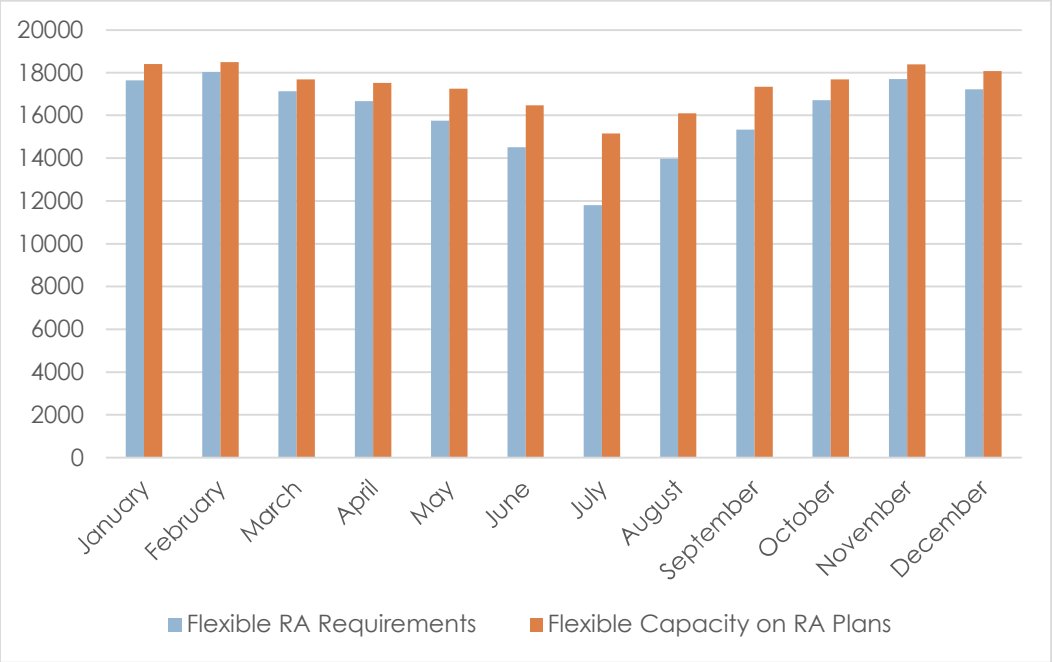
In the allocation cycle for 2020, LSEs submitted revised June through December forecasts to the CEC on March 17, 2020. After reviewing these values, the CEC revised the September load shares. Energy Division used the revised load shares to recalculate individual LSE local requirements, which were then sent to LSEs on April 10, 2020. 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.

2.5 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.[20] 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 4 shows the flexible capacity requirement and the flexible capacity shown on month-ahead RA plans by CPUC-jurisdictional LSEs for each month of 2020.

[20] 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.

Figure 4. Flexible RA Procurement in 2020, CPUC-Jurisdictional LSEs



Source: 2020 RA filings.

3 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 3.1.

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 3.2 and 3.3.

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 3.4.

3.1 Resource Adequacy Contract Price Analysis

Energy Division issued several data requests to all CPUC-jurisdictional LSEs requesting monthly capacity prices paid by (or to) LSEs for every RA capacity contract executed during 2019, 2020, and 2021 for use in calculating the Power Charge Indifference Adjustment (PCIA) RA adder and this RA price analysis. 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 2021 for delivery in 2020-2022, data used in this analysis were restricted to contracts executed in 2019 or 2020 for delivery in 2020.

3.1.1 System Capacity Prices

Table 6 provides a summary of 2020-2022 capacity prices.

Table 6. 2020, 2021, and 2022 Capacity Prices

	2020 Capacity	2021 Capacity	2022 Capacity
Contracted Capacity (MW)	165,422	268,511	244,312
Weighted Average Price ($/kW-month)	$4.97	$5.89	$6.02
Average Price ($/kW-month)	$5.95	$6.47	$6.48
85% of MW at or below ($/kW-month)	$7.60	$8.00	$7.75

Source: 2020-2022 price data submitted by LSEs.

System capacity is comprised of resources that count only towards system capacity and those located in local areas that also count towards local RA requirements. Table 7 provides aggregated capacity prices for all responses, categorized as system-only or local capacity, either north or south of Path 26 (NP-26 and SP-26, respectively). The 2021 Net Qualifying Capacity list is used to identify resources' local area and Path 26 zone.[21] The data set represents 164,619 MW-months of capacity under contract. Of that capacity, 53 percent is located in the NP- zone, and 37 percent is located SP-26 and 10 percent is comprised of capacity imports to CAISO. Of the capacity located within

[21] The 2021 Net Qualifying Capacity list can be found at Resource Adequacy Compliance Materials (ca.gov).

CAISO, 54 percent is located in local areas, with the remaining 36 percent located in the CAISO System area.

The weighted average price for all capacity is $4.97/kW-month. The weighted average price for SP-26 capacity (including local and system RA) is $4.68/kW-month, which is about 7 percent lower than the NP-26 weighted average price of $5.01/kW-month.

The weighted average price of local RA is $4.96/kW-month compared to $4.75/kW-month for system RA capacity. As in 2019, we see that there is little difference in prices for system and local RA. The premium for local RA decreased rapidly over the past few years from 40 percent above system-only capacity as reported in the 2017 RA Report, to 16 percent in the 2018 RA Report, to 7 percent in the 2019 report, and 4 percent in this report, indicating that the market for system RA has tightened.

Table 7. Aggregated RA Contract Prices, 2020

	All RA				Local RA			CAISO System RA		
	Total	NP-26	SP-26	Import	**Subtotal**	NP26	SP26	**Subtotal**	NP26	SP26
Contracted Capacity (MW)	**164,619**	87,048	61,147	16,424	**88,804**	50,670	38,134	**59,391**	36,377	23,013
Percentage of Total Capacity in Data Set	**100%**	53%	37%	10%	**54%**	31%	23%	**36%**	22%	14%
Number of Monthly Values	**6,541**	3,936	2,027	578	**4,063**	2,877	1,186	**1,900**	1,059	841
Weighted Average Price ($/kW-month)	**$4.97**	$5.01	$4.68	$5.88	**$4.96**	$5.04	$4.84	**$4.75**	$4.97	$4.40
Average Price ($/kW-month)	**$5.95**	$6.30	$5.25	$5.97	**$6.24**	$6.54	$5.52	**$5.32**	$5.67	$4.87
85% of MW at or below ($/kW-month)	**$7.60**	$7.75	$7.00	$9.11	**$7.65**	$7.78	$7.00	**$7.05**	$7.50	$6.75

Source: 2020 price data submitted by LSEs.

As noted above, the difference between NP-26 and SP-26 prices has narrowed. The price differential between peak and off-peak months also appears to have decreased.

The monthly weighted average capacity prices for CAISO resources are shown in Table 8 below.

Table 8. RA Capacity Prices by Month and Path 26 Zone, 2020

	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	7,434	5.0%	$4.43	$5.59	$7.50
	South	4,726	3.2%	$4.24	$4.68	$6.24
	Total	12,160	8.2%	$4.36	$5.31	$7.07
Feb	North	7,295	4.9%	$4.38	$5.57	$7.50
	South	4,753	3.2%	$4.17	$4.44	$6.03
	Total	12,048	8.1%	$4.30	$5.19	$7.17
Mar	North	6,883	4.6%	$4.41	$5.49	$7.50
	South	4,816	3.2%	$4.20	$4.29	$6.25
	Total	11,699	7.9%	$4.32	$5.10	$7.25
Apr	North	7,398	5.0%	$4.43	$5.55	$7.50
	South	4,669	3.2%	$4.23	$4.43	$6.25
	Total	12,067	8.1%	$4.35	$5.22	$7.40
May	North	7,605	5.1%	$4.58	$5.56	$7.50
	South	5,139	3.5%	$4.24	$4.43	$6.25
	Total	12,744	8.6%	$4.45	$5.17	$7.13
Jun	North	7,005	4.7%	$4.80	$5.92	$7.51
	South	6,211	4.2%	$4.38	$5.00	$7.00
	Total	13,216	8.9%	$4.60	$5.57	$7.50
Jul	North	7,160	4.8%	$6.39	$7.76	$12.69
	South	4,732	3.2%	$6.33	$6.89	$12.00
	Total	11,891	8.0%	$6.37	$7.48	$12.50
Aug	North	7,306	4.9%	$6.42	$8.24	$13.25
	South	4,965	3.4%	$5.89	$7.35	$12.00

	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	12,271	8.3%	$6.21	$7.95	$13.25
	North	7,191	4.9%	$6.37	$8.20	$13.00
Sep	**South**	4,670	3.2%	$5.69	$7.80	$15.98
	Total	11,861	8.0%	$6.10	$8.06	$13.90
	North	7,347	5.0%	$4.89	$6.18	$7.75
Oct	**South**	5,381	3.6%	$4.64	$4.96	$6.91
	Total	12,729	8.6%	$4.78	$5.73	$7.50
	North	7,363	5.0%	$4.54	$5.57	$7.50
Nov	**South**	5,207	3.5%	$4.24	$4.29	$6.45
	Total	12,570	8.5%	$4.42	$5.12	$7.25
	North	7,061	4.8%	$4.54	$5.58	$7.50
Dec	**South**	5,878	4.0%	$4.13	$4.19	$6.31
	Total	12,939	8.7%	$4.36	$5.08	$7.35

Source: 2020 price data submitted by LSEs.

3.1.2 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. Contracts for unspecified local areas are listed under PG&E Unspecified Local. 2020 weighted average prices for local areas range from $3.86/kW-month in the Bay Area to $7.70/kW-month in Stockton, while 85th percentile prices ranged from $5.50/kW-month for unspecified PG&E local capacity to $9.25/kW-month in Sierra. These are significant increases over prices reported in prior years.

Table 9. Capacity Prices by Local Area, 2020

	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	60,193	40%	$4.75	$5.32	$7.05
LA Basin	17,073	11%	$5.11	$5.55	$7.00
Big Creek-Ventura	12,606	8%	$4.47	$5.70	$7.00
San Diego-IV	8,455	6%	$4.85	$5.37	$7.00
Bay Area	29,367	20%	$3.86	$5.41	$7.00
Fresno	7,250	5%	$5.74	$6.09	$7.40
Humboldt	271	0%	$7.25	$6.79	$7.50
Kern	440	0%	$7.30	$6.91	$7.50
NCNB	4,114	3%	$6.84	$7.11	$8.00
Sierra	6,709	5%	$7.59	$7.50	$9.25
Stockton	1,374	1%	$7.70	$7.53	$8.50
PG&E Unspecified Local	1,144	1%	$5.06	$5.03	$5.50

Source: 2020 price data submitted by LSEs.

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 indicates that while some local areas such as Kern and Big Creek-Ventura have significant price differences between January and August, others such as San Diego-IV and the Bay Area have relatively consistent prices throughout the year.

Table 10. Local RA Capacity Prices by Month, 2020

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CAISO System	Weighted Average	$4.23	$4.10	$4.12	$4.18	$4.24	$4.34	$6.64	$6.16	$6.14	$4.67	$4.25	$3.93
	85th Percentile	$6.10	$6.00	$6.12	$6.25	$6.38	$7.00	$12.00	$13.25	$13.00	$6.75	$6.25	$6.10
LA Basin	Weighted Average	$4.83	$4.72	$4.71	$4.54	$4.67	$4.72	$5.98	$6.69	$6.13	$4.92	$4.59	$4.73
	85th Percentile	$7.00	$7.00	$7.00	$6.75	$6.60	$7.00	$12.50	$12.45	$13.15	$7.25	$7.00	$7.00
Big Creek-Ventura	Weighted Average	$3.81	$3.82	$3.96	$3.92	$4.19	$4.53	$5.76	$5.43	$5.32	$4.72	$4.07	$4.18
	85th Percentile	$6.84	$6.56	$6.45	$6.68	$6.23	$7.94	$14.00	$14.90	$15.61	$7.08	$6.76	$6.45
San Diego-IV	Weighted Average	$4.66	$4.62	$4.61	$4.70	$4.70	$5.11	$5.29	$5.48	$5.66	$4.64	$4.57	$4.60
	85th Percentile	$6.50	$6.50	$6.50	$6.50	$6.49	$6.55	$7.04	$11.75	$14.61	$6.43	$6.45	$6.50
Bay Area	Weighted Average	$3.54	$3.55	$3.51	$3.60	$3.76	$3.98	$4.70	$4.47	$4.23	$3.83	$3.65	$3.67
	85th Percentile	$6.84	$6.90	$6.92	$7.50	$6.92	$7.00	$12.35	$12.45	$12.00	$7.33	$7.00	$7.00
Fresno	Weighted Average	$4.61	$4.50	$4.42	$4.45	$4.55	$5.24	$8.56	$9.40	$8.54	$5.73	$4.72	$4.88
	85th Percentile	$7.40	$7.40	$7.00	$7.00	$7.00	$8.28	$12.70	$14.65	$13.19	$7.38	$7.00	$7.00
Humboldt	Weighted Average	$6.58	$6.58	$6.58	$6.58	$6.62	$6.78	$8.21	$11.30	$8.41	$6.68	$6.68	$6.74
	85th Percentile	$7.12	$7.12	$7.12	$7.12	$7.12	$7.48	$7.63	$12.73	$8.19	$7.50	$7.33	$7.43
Kern	Weighted Average	$6.56	$6.58	$6.69	$6.69	$6.64	$7.08	$7.78	$7.54	$11.02	$7.09	$6.50	$7.30
	85th Percentile	$7.00	$7.50	$7.50	$7.50	$7.50	$7.55	$9.75	$7.58	$12.80	$8.20	$7.52	$7.65
NCNB	Weighted Average	$6.68	$6.66	$6.66	$6.67	$6.60	$6.61	$7.25	$7.40	$7.44	$6.82	$6.60	$6.66
	85th Percentile	$7.95	$7.96	$7.96	$7.72	$7.95	$7.95	$8.50	$8.80	$12.00	$7.90	$7.90	$7.87
Sierra	Weighted Average	$6.57	$6.50	$6.66	$6.51	$6.66	$6.55	$9.27	$9.73	$9.88	$6.72	$6.82	$6.82
	85th Percentile	$7.50	$7.50	$7.68	$7.75	$7.74	$7.50	$14.00	$15.00	$15.85	$7.91	$8.00	$7.64
Stockton	Weighted Average	$7.02	$6.72	$6.66	$7.51	$6.83	$7.52	$9.23	$9.86	$9.46	$7.49	$7.16	$7.15
	85th Percentile	$7.93	$7.64	$7.57	$8.20	$7.50	$8.46	$13.00	$12.98	$14.44	$9.48	$7.77	$7.95

Source: 2020 price data submitted by LSEs.

3.1.3 Flexible Capacity Prices

Table 11 describes capacity prices for flexible capacity located outside of local areas. As seen in previous years, prices for flexible capacity are not higher than those for system capacity. The 2020 weighted average price for flexible capacity is $4.65/kW-month while it is $4.81/kW-month for non-flexible system capacity.

Table 11. Aggregated Non-Local RA Contract Prices Excluding Imports, 2020

	Flexible Capacity	Non-Flexible Capacity	All CAISO System
Contracted Capacity (MW)	24,244	35,949	60,193
Percentage of Total Capacity in Data Set	100%	100%	100%
Weighted Average Price ($/kW-month)	$4.65	$4.81	$4.75
Average Price ($/kW-month)	$4.94	$5.45	$5.32
85% of MW at or below ($/kW-month)	$6.75	$7.50	$7.05

Source: 2020 price data submitted by LSEs.

3.2 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,[22] 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.[23]

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) and Yuba City Energy Center (46 MW) and Dynegy Oakland, LLC's units 1, 2, and 3.

In 2019, for the 2020 compliance year, CAISO extended RMR contracts for four generating facilities: Green Leaf (49.2 MW), CSU Channel Islands (27.5 MW), Oxnard (48.13 MW), and Dynegy Oakland, LLC's units 1, 2, and 3 (165 MW).

3.3 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 if there is:

- 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;

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

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

- Capacity at risk of retirement within the current RA compliance year that will be needed for reliability by the end of the calendar year following the current RA compliance year; and
- Cumulative flexible capacity deficiency in an annual or monthly RA plans.[24]

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, CAISO can procure resources for an initial term of 30 days. The term can be extended beyond the initial period if CAISO determines that the circumstances leading to exceptional dispatch continue to exist.

The CPM price is based on the going forward fixed costs of a reference resource. Since 2016, the CPM price has been determined by a Competitive Solicitation Process (CSP). The CPM tariff includes a soft offer cap initially set at $75.68/kW-year (or $6.31/kW-month) by adding a 20 percent premium to the estimated going-forward fixed costs for a mid-cost 550 MW combined cycle resource with duct firing, as estimated in a 2014 report by the California Energy Commission. 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 ISO.[25] Table 12 shows CAISO's CPM designations for 2020.

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[24] CAISO Reliability BPM, version 41, page 138. https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Reliability%20Requirements.

[25] CAISO 2016 Fourth Quarter Market Issues and Performance Report, March, 2017, page 68, http://www.caiso.com/Documents/2016FourthQuarterReport-MarketIssuesandPerformanceMarch2017.pdf.

Table 12. CAISO CPM Designations for 2020

Resource ID	MW	CPM Type	Term (days)	Start Date	End Date	Est. Cap. Cost /kW-mth	Total Cost
SYCAMR_2_UNIT 4	3.00	Significant Event	30	8/17/2020	9/16/2020	$6.31	$18,930.00
SYCAMR_2_UNIT 3	2.00	Significant Event	30	8/17/2020	9/16/2020	$6.31	$12,620.00
SYCAMR_2_UNIT 2	2.00	Significant Event	30	8/17/2020	9/16/2020	$6.31	$12,620.00
BARRE_6_PEAKER	47.00	Significant Event	30	8/17/2020	9/16/2020	$6.31	$296,570.00
MNDALY_6_MCGRTH	47.20	Significant Event	30	8/17/2020	9/16/2020	$6.31	$297,832.00
SBERDO_2_PSP4	20.00	Significant Event	30	8/17/2020	9/16/2020	$6.31	$126,200.00
SYCAMR_2_UNIT 1	3.41	Significant Event	30	8/17/2020	9/16/2020	$6.31	$21,517.10
SNCLRA_6_PROCGN	26.64	Significant Event	30	8/17/2020	9/16/2020	$6.31	$168,098.40
GATEWY_2_GESBT1	24.00	Significant Event	30	8/17/2020	9/16/2020	$6.31	$151,440.00
SUTTER_2_CISO	250.00	Significant Event	30	8/17/2020	9/16/2020	$6.31	$1,577,500.00
GATEWY_2_GESBT1	7.50	Significant Event	30	8/18/2020	9/17/2020	$6.31	$47,325.00
BIGCRK_2_EXESWD	15.00	Significant Event	30	8/19/2020	9/18/2020	$6.31	$94,650.00
DUANE_1_PL1X3	8.70	Exceptional Dispatch	30	8/16/2020	9/15/2020	$6.31	$54,897.00
GATEWY_2_GESBT1	20.00	Exceptional Dispatch	30	8/17/2020	9/16/2020	$6.31	$126,200.00
HUMBPP_1_UNITS3	15.73	Local Reliability	60	9/1/2020	10/31/2020	$6.31	$198,512.60
ARCOGN_2_UNITS	12.00	Significant Event	30	9/6/2020	10/6/2020	$6.31	$75,720.00
SUTTER_2_CISO	250.00	Significant Event	30	10/1/2020	10/31/2020	$6.31	$1,577,500.00

Source: CPM Designation posted by CAISO at http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=33EB5656-7056-4B8E-87B2-3EA3D816DA62.

3.4 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.

3.4.1 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 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 13 provides the scheduling resource ID, the contract dates that the CAM was approved to cover, the authorized IOU, and August NQC values for all 2020 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 13. CAM Reliability Resources as of 2020

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
ALAMIT_2_PL1X3	6/1/2020	5/31/2040	SCE	674.7
BARRE_6_PEAKER	8/1/2007	UOG	SCE	47
BUCKBL_2_PL1X3	8/1/2010	7/31/2020	SCE	493.63
CARLS1_2_CARCT1	12/1/2018	9/30/2038	SDG&E	422
CARLS2_1_CARCT1	12/1/2018	9/30/2038	SDG&E	105.5
CENTER_6_PEAKER	7/20/2007	UOG	SCE	47.11
CHINO_2_APEBT1	12/31/2016	12/30/2026	SCE	20

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
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	UOG	SDG&E	7.5
ELKHIL_2_PL1X3	1/1/2016	12/31/2020	SCE	380
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	UOG	SDG&E	10
ESCNDO_6_EB2BT2	3/6/2017	UOG	SDG&E	10
ESCNDO_6_EB3BT3	3/6/2017	UOG	SDG&E	10
ESCNDO_6_PL1X2	5/1/2014	12/31/2039	SDG&E	48.71
ETIWND_6_GRPLND	7/17/2007	UOG	SCE	47.39
GOLETA_2_VALBT1	12/1/2020	11/30/2040	SCE	10
GOLETA_6_ELLWOD	1/1/2019	12/31/2020	SCE	54
HNTGBH_2_PL1X3	5/1/2020	4/30/2040	SCE	673.8
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	8/1/2009	UOG	SCE	47.2
OhmConnect, Inc.	1/1/2019	12/31/2024	SDG&E	4.5
ORMOND_7_UNIT 2	1/1/2019	12/31/2020	SCE	750
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
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
STANTN_2_STAGT1	7/1/2020	6/30/2040	SCE	49.65
STANTN_2_STAGT2	7/1/2020	6/30/2040	SCE	49.65
VESTAL_2_WELLHD	1/16/2013	1/15/2023	SCE	49
WALCRK_2_CTG1	6/1/2013	5/31/2023	SCE	96.43

Scheduling Resource ID	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, 2020. For resources that began after August 2020, the August 2021 NQC is provided. NQC values can change monthly and annually.

3.4.2 QF/CHP Resources

D.10-12-035[26] 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.[27] 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.[28] Table 14 below lists the CHP resources whose RA capacity was allocated as of 2020.

[26] http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/128624.htm

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

[28] 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 14. CHP Resources Allocated for CAM as of 2020

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	40.2	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	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	15.63	SCE
SNCLRA_6_PROCGN	10/1/2019	9/30/2026	20.50	SCE
STOILS_1_UNITS	11/1/2019	10/31/2026	5.14	PG&E
SUNSET_2_UNITS	7/10/2014	12/31/2050	229.5	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
TANHIL_6_SOLART	12/1/2019	11/30/2026	9.92	PG&E

Scheduling Resource ID	CAM Start Date	CAM End Date	August NQC*	Authorized IOU
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 2020. If the unit was not CHP CAM in August, 2020, then the applicable August NQC is shown. NQC values can change monthly and annually.

3.4.3 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 15 lists the DRAM capacity procured by the IOUs for 2020.

Table 15. DRAM Capacity Allocated for CAM for 2020

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
Multiple	6/1/2020	12/31/2020	PG&E	98.92
Multiple	6/1/2020	12/31/2020	SCE	95.25
Multiple	6/1/2020	12/31/2020	SDG&E	21.6
			TOTAL	**215.77**

*NQC values can vary by month.

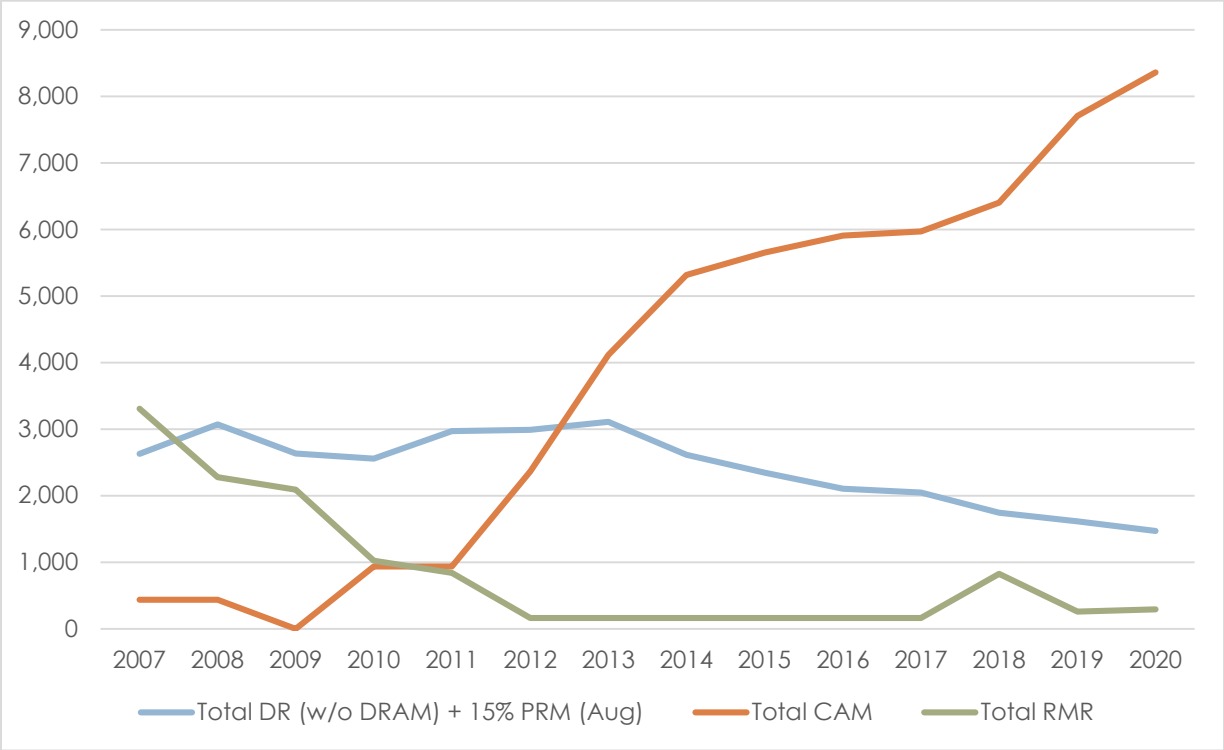
Event-based DR resources are market-integrated and are also treated as an RA credit. The costs for most DR programs are allocated through the distribution charge, which means that these DR programs are paid for by bundled customers, direct access customers, and the customers of community choice aggregators. 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 16 and Figure 8 below illustrate the amounts and types of procurement credit that have been allocated since the beginning of the RA program. The graph reflects the decline in RMR units until 2018 and the increase in CAM units. DR RA credits have declined slightly since 2013. The total amount of capacity procured through DR, CAM, and RMR for August 2020 was 11,104 MW. This is about 24 percent of the total CPUC-jurisdictional LSE obligation for August 2020 (46,241 MW). In August 2020, total CAM procurement reached 9,342 MW and RMR procurement increased from 256 MW in 2019 to 290 MW in 2020.

Table 16. DR, CAM, and RMR Allocations for August (MW)

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
DR	SCE	1,705	1,616	1,613	1,838	2,067	2,195	1583	1593	1480	1437	1215	1125	1031
	PG&E	1018	912	846	888	744	783	933	689	565	566	488	448	424
	SDG&E	346	104	97	241	177	135	96	63	60	42	40	39	17
	Total DR w/out DRAM (Aug)	**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**
CAM	SCE	436	436	936	936	1,529	2,763	3,477	3,583	3,848	3,702	4,091	4,742	6,515
	PG&E					703	1,351	1,790	2,020	2,008	1,868	1,897	1,989	1,848
	SDG&E					130		49	49	49	399	413	975	980
	Total CAM (Aug)	**436**	**436**	**936**	**936**	**2,362**	**4,114**	**5,316**	**5,652**	**5,905**	**5,969**	**6,401**	**7,706**	**9,342**
RMR	SCE													75.63
	PG&E	1,303	1,263	709	527	165	165	165	165	165	165	826	256	214.2
	SDG&E	973	828	311	311									0
	Total RMR	**2,276**	**2,091**	**1,020**	**838**	**165**	**165**	**165**	**165**	**165**	**165**	**826**	**256**	**290**
DR+CAM+ RMR		**5,781**	**5,159**	**4,512**	**4,741**	**5,515**	**7,392**	**8,094**	**8,162**	**8,175**	**8,179**	**8,970**	**9,574**	**11,104**

Figure 5. RA Procurement Credit Allocation, 2006 – 2020 (RMR, August DR, and August CAM)



4 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[29] 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.[30]

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.

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[29] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/119856.htm (QC manual adopted as Appendix B).

[30] 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.

4.1 New Resources and Retirements in 2020

Overall, 2019-2020 saw an increase in available capacity. A total of 1,532.12 MW of capacity retired in 2020 including the 335 MW Inland Empire Energy Center, Unit 1, but this was more than offset by 2,267.63 MW of new resources.

Table 17 lists the new facilities that came online in 2020 and Table 18 lists the retiring and mothballed facilities for 2020. 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 2020, the net dependable capacity of new facilities was about 3,934.53 MW which was more than 1,600 MW over the assigned NQC values.

Table 17. New NQC Resources Online in 2020

Resource ID	Resource Name	Technology	NQC	Net Dependable Capacity
AKINGS_6_AMESR1	American Kings Solar	Solar PV	33.21	123
ALAMIT_2_PL1X3	Alamitos Energy Center Unit 7	Combined Cycle	674.7	674.7
ALAMIT_7_ES1	Alamitos Energy Storage	Battery Storage	100	100.45
ALMASL_2_GS1SR1	Almasol Generating Station 1	Solar Hybrid	33.75	125
ALMASL_2_GS4SR4	Almasol Generating Station 4	Solar Hybrid	27	100
CABALO_2_M2WSR2	Mustang 2 Whirlaway Solar	Solar PV	27	100
DRACKR_2_DS3SR3	Dracker Solar Unit 3	Solar Hybrid	0	125
DRACKR_2_DS4SR4	Dracker Solar Unit 4	Solar Hybrid	16.88	62.5

Resource ID	Resource Name	Technology	NQC	Net Dependable Capacity
DSRTHV_2_DH1SR1	Desert Harvest	Solar PV	21.6	80
DSRTHV_2_DH2SR2	Desert Harvest 2	Solar PV	18.9	70
GATEWY_2_GESBT1	Gateway Energy Storage	Battery Storage	50	250
HARDWK_6_STWBM1	Still Water Ranch Dairy	Biogas	0	1
HIGGNS_1_COMBIE	Combie South	Hydro	0.35	1.5
HNTGBH_2_PL1X3	Huntington Beach Energy	Combined Cycle	673.8	673.8
KYCORA_6_KMSBT1	Kearny Mesa Storage	Battery Storage	0	1
LNCSTR_6_SOLAR2	SEPV Sierra NGR	Solar Hybrid	0.32	2.75
LOTUS_6_LSFSR1	Lotus Solar Farm	Solar PV	13.5	50
LTBEAR_1_LB3SR3	Little Bear 3 Solar	Solar PV	5.4	20
LTBEAR_1_LB4SR4	Little Bear 4	Solar PV	13.5	50
LTBEAR_1_LB4SR5	Little Bear 4 Solar 5	Solar PV	13.5	50
LTBERA_1_LB1SR1	Little Bear Solar 1	Solar PV	10.8	40
RTEDDY_2_SC1SR3	Rosamond West Solar Clean	Solar PV	10.8	40
RTEDDY_2_SEBSR3	Rosamond West Solar East Bay 3	Solar PV	15.12	56
RTEDDY_2_SEBSR4	Rosamond West Solar East Bay 4	Solar PV	15.12	56
RTEDDY_2_SPASR4	Rosamond West Solar Palo Alto	Solar PV	7.02	26
RTEDDY_2_SRXSR4	Rosamond West Solar Rosie X	Solar PV	3.67	13.6
STANTN_2_STAGT1	Stanton 1	Combustion Turbine Hybrid	49.65	49.65
STANTN_2_STAGT2	Stanton 2	Combustion Turbine Hybrid	49.65	49.65
SUTTER_2_CISO	Sutter Power Plant Pseudo-CISO	Combined Cycle	275	275
TITANS_2_TTSSR1	Titan Solar 1 Pseudo	Solar PV	18.9	70
VOLTA_7_PONHY1	Snow Mountain	Hydro	0.9	1.25
WHITEH_2_MEADDYN 1	White Hills A	Wind	10.5	50
WHITEH_2_MEADDYN 2	White Hills B	Wind	63	300
WSTWND_2_M89WD1	Mojave 89	Wind Hybrid	17.36	82.65

Resource ID	Resource Name	Technology	NQC	Net Dependable Capacity
WSTWND_2_M90WD2	Mojave 90	Wind Hybrid	13.61	48.85
		Total	**2267.63**	**3934.53**

Source: 2019-2020 NQC lists posted to the CAISO website.[31]

Table 18. Resources Retired in 2020

Resource ID	Resource Name	Technology	NQC	Status
INLDEM_5_UNIT 1	Inland Empire Energy Center, Unit 1	Combined Cycle	335	Retired
HNTGBH_7_UNIT 1	Huntington Beach Unit 1	Steam Turbine	225.75	Retired
ALAMIT_7_UNIT 1	Alamitos Gen Sta. Unit 1	Steam Turbine	174.56	Retired
ALAMIT_7_UNIT 2	Alamitos Gen Sta. Unit 2	Steam Turbine	175	Retired
ALAMIT_7_UNIT 6	Alamitos Gen Sta. Unit 6	Steam Turbine	495	Retired
MONLTS_2_MONWD4	Monolith 4	Wind	1	Retired
MONLTS_2_MONWD5	Monolith 5	Wind	0.85	Retired
MONLTS_2_MONWD6	Monolith 6	Wind	1.1	Retired
MONLTS_2_MONWD7	Monolith 7	Wind	1	Retired
VINCNT_2_QF	Vincent QFs	Wind	43.47	Retired
DEVERS_1_QF	Devers QFs	Wind	1.68	Mothballed
VENWD_1_WIND1	Windpark Unlimited 1	Wind	1.98	Mothballed
VENWD_1_WIND2	Windpark Unlimited 2	Wind	3.37	Mothballed
VENWD_1_WIND3	Painted Hills Windpark	Wind	4	Mothballed
MIDWD_6_WNDLND	Windland Refresh 1	Wind	1.56	Mothballed
MIDWD_2_WIND1	Windland Refresh 2	Wind	1.64	Mothballed
OLINDA_7_LNDFIL	Olinda Landfill Generating Facility	Biogas	0	Retired
LAGBEL_6_QF	Laguna Bell QFs	Various	0.33	Retired
ANAHM_7_CT	Anaheim Combustion Turbine	Gas Turbine	40.64	Retired

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

SBERDO_2_QF	San Beradino QFs	Cogeneration	0.07	Retired
MESAS_2_QF	Mesa QFs	Various	0	Retired
GARNET_2_DIFWD1	Difwind	Wind	1.65	Retired
PANSEA_1_PANARO	Mesa Wind Project	Wind	6.3	Retired
JAWBNE_2_SRWND	Sky River	Wind	16.17	Mothballed
		Total	**1,532.12**	

Source: CAISO Announced Retirement and Mothball list. [32]

A summary of the current status of plants subject to CEC siting review and under construction, which may eventually be added to California's resource pool, is available on the CEC website.[33]

4.2 Aggregate NQC Values 2016 through 2021

Table 19 shows aggregate NQC values from the CAISO NQC lists for 2016 through 2021.[34] The total 2021 NQC (as reported on the CAISO NQC list) decreased by 2,992 MW from the 2020 NQC list, due to retirements expected in 2021 exceeding the new units in 2020. The number of resources on the NQC list continued to grow as demand response resources were integrated into the CAISO market. There are also changes in NQC for facilities that began operation in the previous year after August NQC values were determined and for facilities that are partially online and received an initial NQC value for partial capacity.

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

[33] https://ww2.energy.ca.gov/sitingcases/alphabetical_cms.html.

[34] Note that MW changes in NQC lists do not align with the calendar year changes described in section 4.1 since the NQC list for each year is prepared in the fall of the previous year.

Table 19. Final NQC Values for 2016-2021

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	45,997	1,614	-2,992	-347
2016-21			**-7,176**	**642**

Source: NQC lists from 2016 through 2021.

5 COMPLIANCE WITH RA REQUIREMENTS

5.1 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 2020 compliance year. The workshop, RA guide, and templates were designed to assist LSEs in demonstrating compliance with the RA program.

The final 2020 filing guide[35] and templates were made available to LSEs in September 2019. Changes were made to implement the new RA rules discussed in section 1.2. As in previous years, the CPUC required all filings to be submitted simultaneously to the CAISO and CEC.

5.2 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

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

compliance, approves compliant filings, and sends an approval letter to each LSE (noncompliant filings are discussed in the Subsections 5.3 and 5.4).

5.3 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, CAISO, and CEC 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.

5.4 Enforcement Actions in the 2012 through 2020 Compliance Years

Pursuant to CPUC Resolution E-4195,[36] 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.

Table 20 summarizes citations issued and enforcement actions taken by the CPUC since 2012. From 2012 through 2020, the CPUC issued 81 citations for violations and took no enforcement action. In 2020, twenty citations were issued for penalties of $2,707,435.[37]

[36] See: http://docs.cpuc.ca.gov/PUBLISHED/FINAL_RESOLUTION/93662.htm.

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

Table 20. Enforcement Summary Pursuant to the RA Program Since 2012

Compliance Year	Citations Issued	LSEs Cited	Citation Penalties Issued	Enforcement Cases	LSEs Enforced	Enforcement Penalties
2012	4	Glacial Energy of CA, Shell Energy, SDG&E, Direct Energy Business	$14,600	0	0	0
2013	5	SDG&E, Commerce Energy, 3 Phases, Liberty Power (2)	$26,500	0	0	0
2014	1	3 Phases	$5,000	0	0	0
2015	6	3 Phases (2), Commerce Energy (2), EDF Industrial, Glacial Energy	$38,000	0	0	0
2016	3	Tiger Natural Gas, Glacial Energy, Shell Energy	$13,500	0	0	0
2017	6	Commercial Energy of Montana (2), CleanPowerSF, Southern California Edison, Direct Energy Business, Tiger Natural Gas	$150,110	0	0	0
2018	10	AmericanPowerNet Management, Just Energy Solutions (5), Direct Energy Business, Pilot Power Group, Pioneer Community Energy (2)	$2,596,739	0	0	0
2019	26	Just Energy Solutions (11), Pioneer Community Energy, Valley Clean Energy (2), East Bay Community Energy, San Jose Clean Energy, Agera Energy (3), Commercial Energy (7)	$9,552,745	0	0	0

Compliance Year	Citations Issued	LSEs Cited	Citation Penalties Issued	Enforcement Cases	LSEs Enforced	Enforcement Penalties
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	0	0	0
Total	81		$15,104,629	0	0	0

6 APPENDIX

2020 List of CPUC Jurisdictional LSEs

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

32. San Jacinto Power
33. Sonoma Clean Power Authority
34. Silicon Valley Clean Energy Authority
35. Tiger Natural Gas, Inc.
36. The Regents of the University of California
37. Valley Clean Energy Alliance