2019 RESOURCE ADEQUACY REPORT

March 2021

CALIFORNIA PUBLIC UTILITIES COMMISSION
ENERGY DIVISION

A digital copy of this report can be found at:

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

Report Authors:
Jonathan L. Lakey – Senior Analyst
Simone Brant – Senior Analyst
Lily Chow – Senior Analyst
Michele Kito – Supervisor, Resource Adequacy and Procurement Section
Judith Iklé – Program Manager, Procurement Strategy and Oversight, Energy Division

CONTENTS

TABLES

FIGURES

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 or Commission) 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 continues 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 2019 RA compliance year. While this report does not make explicit policy recommendations, it provides information relevant to the currently open RA rulemakings (R.17-09-020 and R.19-11-009) 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 September 2019 of 41,336 MW, which represented a 1.9 percent increase from the peak forecast of 40,577 MW for 2018. The plausibility adjustments as a percentage of each month's aggregated year-ahead forecast ranged from -1.4 percent to 11.7 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

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

procured 100 percent of their local RA obligation for all twelve months. LSEs are also 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, on a monthly basis from July through December, the LSEs must demonstrate they have met 100 percent of their local obligation which is revised to reflect load migration.

In 2019, CPUC-jurisdictional LSEs were deficient by 495 MW in meeting their peak load RA obligations. The 2019 peak demand (for CPUC-jurisdictional LSEs, after net load migration adjustments) was forecasted to occur in September 2019 at 41,336 MW. The RA obligation for September, including a 15 percent planning reserve margin, totaled 47,882 MW and LSEs collectively procured 47,387 MW.

Although CPUC jurisdictional LSEs were deficient in meeting 2019 September Month Ahead RA obligations, the actual peak load occurred in August. The actual peak load for CAISO's Balancing Authority Area was 44,148 MW and occurred at 6pm on August 15, 2019.[2] This value includes both CPUC-jurisdictional and non-CPUC-jurisdictional LSEs with CPUC-jurisdictional LSEs serve approximately 90 percent of actual peak load, or about 39,733 MW.

CPUC-jurisdictional LSEs did not collectively meet all local RA requirements during the 2019 compliance year. The 2019 local RA procurement obligations for CPUC-jurisdictional LSEs totaled 21,935 MW. LSEs and CAISO procured a monthly minimum of 22,041 MW. Physical resources, cost allocation mechanism (CAM) resources, reliability must-run (RMR) resources, and demand response (DR) resources contributed to this total.

In 2019, total committed RA resources ranged from 30,947 MW in March to 47,565 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

[2] Load data is from CAISO's EMS system. CAISO reported system peak at 44,148 MW. See http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx. The actual peak for CAISO is higher than the CPUC jurisdictional load because it includes CPUC non-jurisdictional load.

through to all customers by Transmission Access Charge (TAC) area, also contributed to meeting RA obligations. Between 84 and 93 percent of all committed RA capacity, including CAM, was procured by LSEs from unit-specific physical resources within the CAISO control area, 3 to 11 percent of capacity was from imports, and 3 to 4 percent was from DR resources. CAM and RMR resources consisted of 17 to 25 percent of total RA capacity procured. Resources procured by CAISO through its capacity procurement mechanism (CPM) made up 2 to 3 percent. In general, CAM procurement has continued to increase since 2011, RMR procurement decreased to one resource in 2011, but increased in 2018, and DR procurement has declined since 2013[3].

While new resources were added during 2019, the overall capacity that can be used to meet LSEs' RA requirements decreased due to retirement of 650 MW of older gas and cogeneration facilities. This was partially offset by 392 MW of new resources, but overall, 2019 saw a decrease in available capacity.

Because the RA program requires LSEs to acquire capacity to meet load and reserve requirements, the Commission issues citations or initiates enforcement actions when LSEs do not fully comply with RA program rules.[4] In total, the Commission issued ten citations for violations related to compliance year 2019 for a total of $9,553,046.

[3] The Utilities have anecdotally attributed the decline in Demand Response participation to the following: 1. Customer migration to the Demand Response Auction Mechanism (DRAM); 2. The frequency and length of dispatches; 3. The greater adoption of and migration to Time-of-Use (TOU) rates; 4. The change in the Availability Assessment Hours (AAH); and 5. The implementation of the Prohibited Resources policy (D.16-09-056).

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

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 or Commission) jurisdictional Load Serving Entities (LSEs)[5] have sufficient capacity to meet their peak load with a 15 percent reserve margin. The RA program began implementation in 2006 and continues 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 2019 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 rulemakings (R.17-09-020 and R.19-11-009) 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.

[5] Commission 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[6] 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 August. The forecasts and allocations together determine both the annual and monthly system RA obligations.

1.2 Changes to the Resource Adequacy Program for 2019

In D.18-06-030, the Commission made the following changes to the RA program:

- Required all LSEs to participate in the year-ahead resource adequacy process in order to serve load in the subsequent compliance year.

---

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

- Modified the resource adequacy measurement hours HE17-HE21 (4:00 p.m. – 9:00 p.m.) for each month of the year beginning in 2019.

- Allowed combined storage and demand response projects to be eligible to participate in the Resource Adequacy program.

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 2019 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.[7] The 2019 revised annual forecasts were due on August 17, 2018. 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 August 10 and final allocations to LSEs on September 20, 2018.

LSEs file historical load information	**March 16, 2018**
LSEs file 2019 year-ahead load forecast	**April 20, 2018**
LSEs receive 2019 year-ahead RA obligations	**August 10, 2018**
Final date to file revised forecasts for 2019	**August 17, 2018**
LSEs receive revised 2019 RA obligations	**September 20, 2018**

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.[8] As discussed in the RA Guide for the 2019 compliance year, LSEs must submit a revised

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

[8] 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.[9] These load forecast adjustments are solely for load migration between LSEs, not changing demographic or electrical conditions. Per D.10-06-036,[10] 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 2019 and the adjustments that were made by the CEC across the three IOU service areas.[11] 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 September 2019 of 41,336, which represented a 1.9 percent increase from the peak forecast of 40,577 MW for 2018.[12]

---

[9] Annual RA Filing Guides are available on the CPUC website: http://www.cpuc.ca.gov/General.aspx?id=6311.

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

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

[12] The 2018 RA report can be found at: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/2018%20RA%20Report%20rev.pdf.

Table 1. 2019 Aggregated Load Forecast Data (MW) - Results of Energy Commission Review and Adjustment to the 2019 Year-Ahead Load Forecast

Element	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Submitted LSE Forecast	27,843	27,090	26,818	26,868	30,194	34,573	38,566	42,100	36,578	29,801	27,391	28,828
Adjustment for Plausibility and Migrating Load	(104)	31	(181)	1,510	1,803	3,884	2,606	(586)	4,784	3,962	137	(349)
EE/DG/DR Adjustment	(940)	(951)	(1,040)	(1,148)	(1,504)	(1,659)	(1,699)	(1,754)	(1,665)	(1,568)	(1,163)	(1,136)
Pro Rata Adjustment	1,427	1,688	3,165	4,787	4,037	4,779	2,760	4,683	3,443	3,493	3,176	1,729
Non-Coincident Peak Demand	**28,226**	**27,859**	**28,762**	**32,017**	**34,530**	**41,578**	**42,234**	**44,444**	**43,141**	**35,689**	**29,540**	**29,072**
Coincidence Adjustment	(1,571)	(1,788)	(2,879)	(3,368)	(2,470)	(2,883)	(2,180)	(3,729)	(1,805)	(1,811)	(2,268)	(1,304)
Final Load Forecast Used for Compliance	**26,655**	**26,072**	**25,883**	**28,649**	**32,060**	**38,694**	**40,054**	**40,714**	**41,336**	**33,878**	**27,272**	**27,768**

Source: CEC Staff.

2.1.2 Year-Ahead Plausibility Adjustments and Monthly Load Migration

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. Table 2 below presents the aggregate monthly plausibility adjustments for all LSEs from 2013 to 2019 and calculates the 2019 monthly plausibility adjustments as a percentage of the monthly year-ahead forecast for 2019.

In 2019, the CEC's plausibility adjustments decreased load for January, March, August, and December and increased load for all other months. The CEC found that all but one LSE required adjustments to their load forecast. This is a larger number of adjustments than in 2018, when 2 of 9 community choice aggregators (CCAs), 7 of 14 ESPs, and all IOUs required plausibility adjustments in at least one month. The 2019 monthly plausibility adjustments as a percentage of that month's aggregated year-ahead forecast ranged from -1.44 percent to 11.7 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. 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, 2013-2019 (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)
2019 Plaus. Adj./Load	-0.39%	0.12%	-0.70%	5.27%	5.62%	10.04%	6.51%	-1.44%	11.57%	11.70%	0.50%	-1.26%

Source: Year-ahead CEC load forecasts, 2013-2019.

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 2019. 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 2.82 percent for February 2019. On a megawatt basis, the net monthly load migration adjustments ranged from -59 to 735 MW.

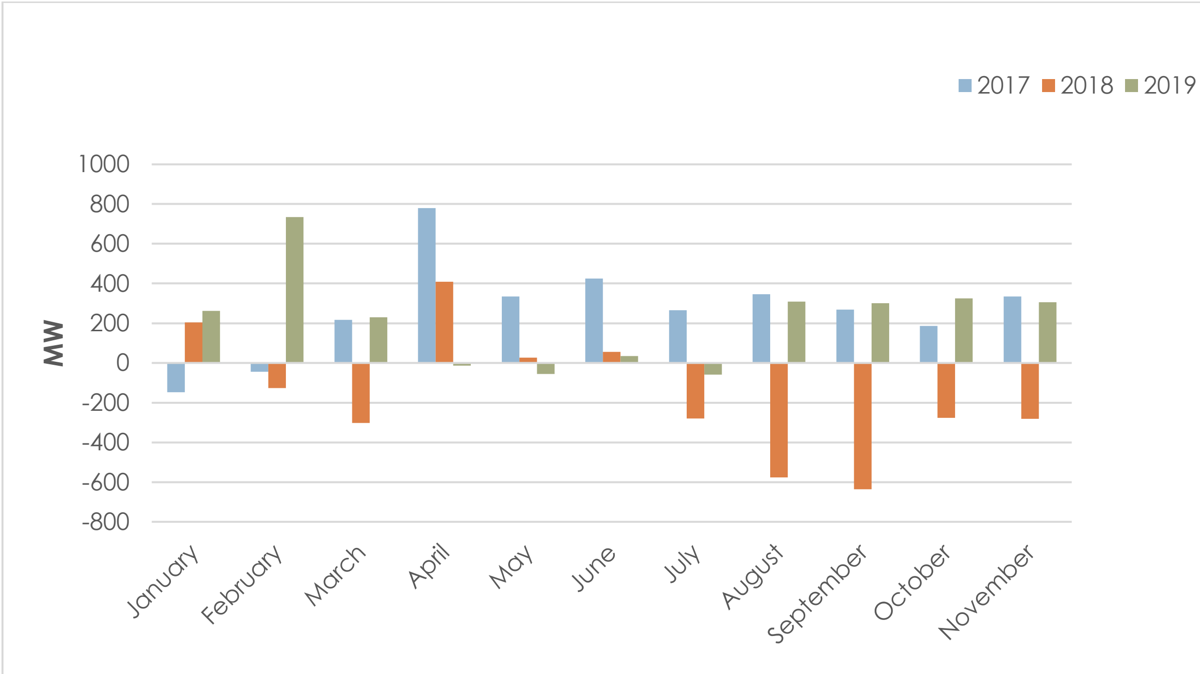
Table 3. Summary of Load Migration Adjustments in 2019 (MW)

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Final YA Load Forecast	26,655	26,072	25,883	28,649	32,060	38,694	40,054	40,714	41,336	33,878	27,272	27,768
Monthly Adjustments	261	735	230	(14)	(56)	35	(59)	308	300	325	305	402
Final Forecasts in Monthly RA Filings	26,916	26,806	26,114	28,635	32,004	38,729	39,995	41,022	41,636	34,203	27,578	28,170
Monthly Adjustments/ Final YA Load Forecast	0.98%	2.82%	0.89%	-0.05%	-0.17%	0.09%	-0.15%	0.76%	0.73%	0.96%	1.12%	1.45%

Source: Load forecast adjustments submitted to the CEC and CPUC in 2019.

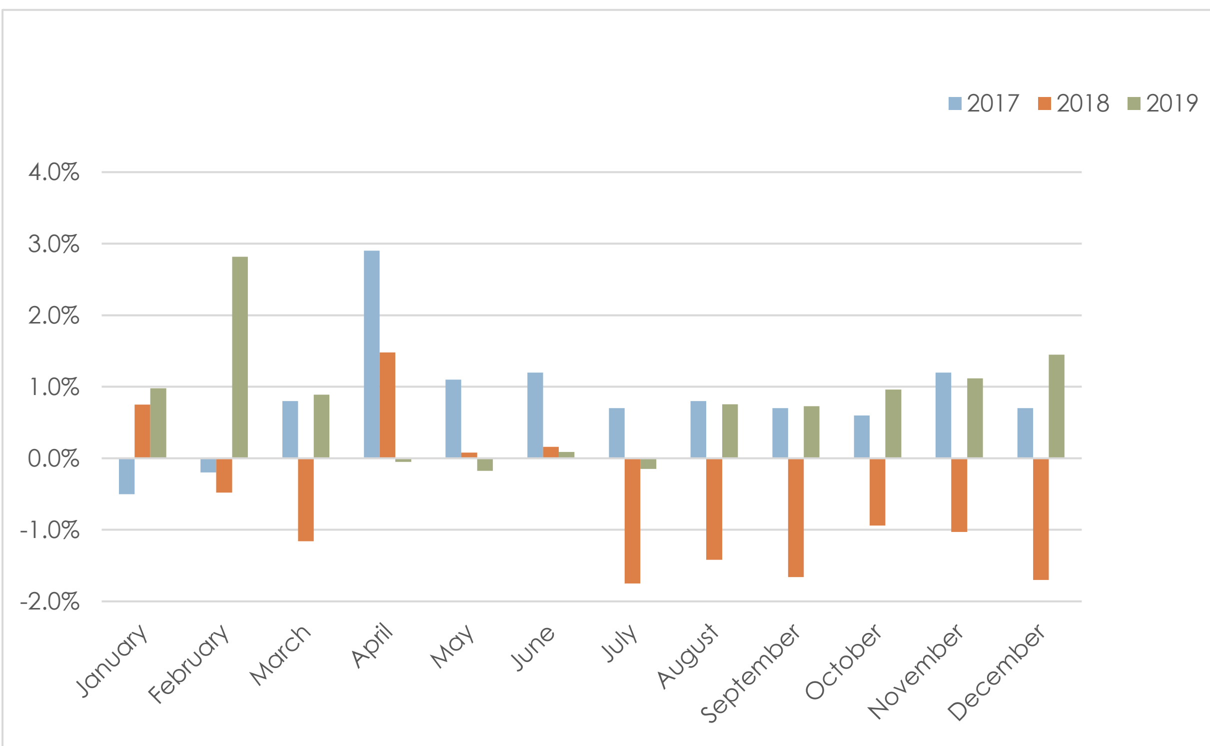
Net load migration should be close to zero, since it is defined as customers transferring directly from one LSE to another. Discrepancies in the adjustments made by LSEs gaining and losing customers, however, can cause overall load migration adjustments to deviate from zero. In recent years, the CPUC 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 2019. Load migration remained relatively low throughout this period, with monthly migration remaining below 800 MW and 3 percent of total load.

Figure 1. Net Load Migration Adjustments per Month (MW), 2016-2019



Source: Monthly forecast adjustments submitted by LSEs, 2016-2018.

Figure 2. Net Load Migration as Percentage of Total Forecasted Load, 2017-2019



Source: Monthly forecast adjustments submitted by LSEs, 2016-2018.

2.2 System RA Requirements for CPUC-Jurisdictional LSEs

CPUC-jurisdictional LSEs met their collective system RA requirements for every month of 2019 except September where 99 percent of requirements were met. For those months that were not deficient, the total MW of RA resources procured exceeded the total system Resource Adequacy Requirement (RAR) by 0.5 to 5.3 percent, depending on the month.[13] Table 4 shows the total CPUC-jurisdictional RA procurement for each month of 2019, 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. RA obligations are reported here as 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.

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

Table 4. 2019 RA Filing Summary – CPUC-Jurisdictional Entities (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
RAR without DR,CAM, & RMR	30,954	30,827	30,031	32,930	36,805	44,539	45,995	47,176	47,882	39,334	31,714	32,396
CAM	7,621	7,642	7,617	7,668	7,701	7,742	7,649	7,706	7,731	7,670	7,740	7,790
Phys. Res. (w/ CAM)	29,221	28,182	27,511	30,693	33,332	39,894	39,051	41,330	40,530	35,388	29,344	30,925
Imports	1,999	1,788	1,895	1,409	2,235	3,192	4,901	3,968	4,737	2,190	1,332	866
DR plus 15% PRM	1,076	1,189	1,195	1,447	1,630	1,811	1,957	1,943	1,787	1,673	1,279	1,169
RMR	231	231	231	231	231	231	231	231	231	231	231	231
Pref. LCR Credit	66	111	114	69	73	88	84	93	103	84	93	103
CPM	0	0	0	0	0	0	0	0	0	0	0	0
Total	32,592	31,501	30,947	33,849	37,501	45,216	46,224	47,565	47,387	39,565	32,279	33,293
Total/RAR	**105.3%**	**102.2%**	**103.1%**	**102.8%**	**101.9%**	**101.5%**	**100.5%**	**100.8%**	**99.0%**	**100.6%**	**101.8%**	**102.8%**

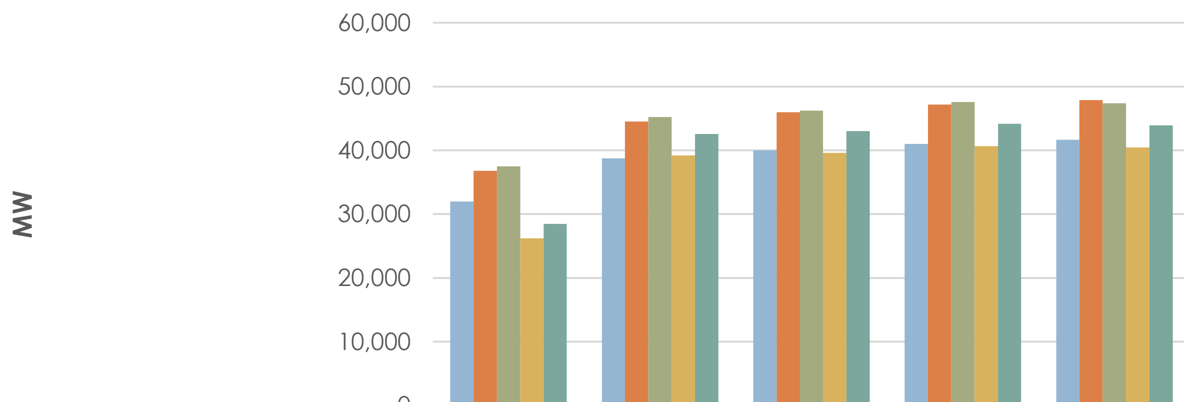
Source: LSE Monthly RA Filings.

In 2019, total committed RA resources ranged from 30,947 MW in March to 47,565 MW in August. Between 84 and 93 percent of all committed RA capacity, including CAM, was procured by LSEs from unit-specific physical resources within the CAISO control area, 3 to 11 percent of capacity was from imports, and 3 to 4 percent was from DR resources. CAM and RMR resources consisted of 17 to 25 percent of total RA capacity procured. These resources enabled CPUC-jurisdictional LSEs to meet between 99 and 101.9 percent of total procurement obligations in each summer month. The actual peak demand in CAISO of 44,148 MW, which includes CPUC-jurisdictional and non-CPUC jurisdictional LSEs, occurred on August 15, 2019; this was lower than the 2018 peak of 46,427 MW.[14] About 90 percent of 2019 actual peak load, or about 39,733, could be attributed to CPUC-jurisdictional LSEs.

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

Figure 3 shows the 2019 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 peak can be higher than CPUC RA obligations and total RA committed because it includes non-CPUC jurisdictional load.

Figure 3. 2019 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.)	32,004	38,729	39,995	41,022	41,636
Forward Commitment Obligation	36,805	44,539	45,995	47,176	47,882
Total RA Resources Committed	37,501	45,216	46,224	47,565	47,387
Est. Peak Load (CPUC-juris.)	26,192	39,203	39,616	40,649	40,454
Actual Peak Load (CAISO)	28,446	42,577	43,025	44,148	43,936

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

2.3 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.[15] The 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.18-06-030, the CPUC adopted the 2019 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). As in previous years, the following local areas were aggregated into "Other PG&E Areas" in 2019 for RA compliance: Humboldt, North Coast/North Bay, Sierra, Stockton, Fresno, and Kern.

2.3.1 Year-Ahead Local RA Procurement

Table 5 summarizes the 2019 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 three of the five local areas by 1.5 to 7.7 percent

[15] Local Capacity Requirement (LCR) studies and materials for 2019 and previous years are posted at http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx.

Table 5. Local RA Procurement in 2019, CPUC-Jurisdictional LSEs

Local Areas in 2019	Total LCR	CPUC-Jurisdictional Local RAR	Minimum Physical Resources per Month	Local RMR & CAM Credit	Local DR	Minimum Procurement/ Local RAR
LA Basin	8,116	7,288	7,397	2,393	686	101.5%
Big Creek/Ventura	2,614	2,086	2,149	1,312	169	103.0%
San Diego-IV	4,026	4,027	3,818	940	34	94.8%
Greater Bay Area	4,461	3,747	4,037	872	116	107.7%
Other PG&E Areas	5,387	4,786	4,641	320	184	97.0%
Totals	24,604	21,935	22,041	5,837	1,189	100.00%

Source: 2019 Year Ahead RA filings.

2.3.2 Local and Flexible RA True-Ups

As part of the partial reopening of direct access in 2010, the Commission 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.

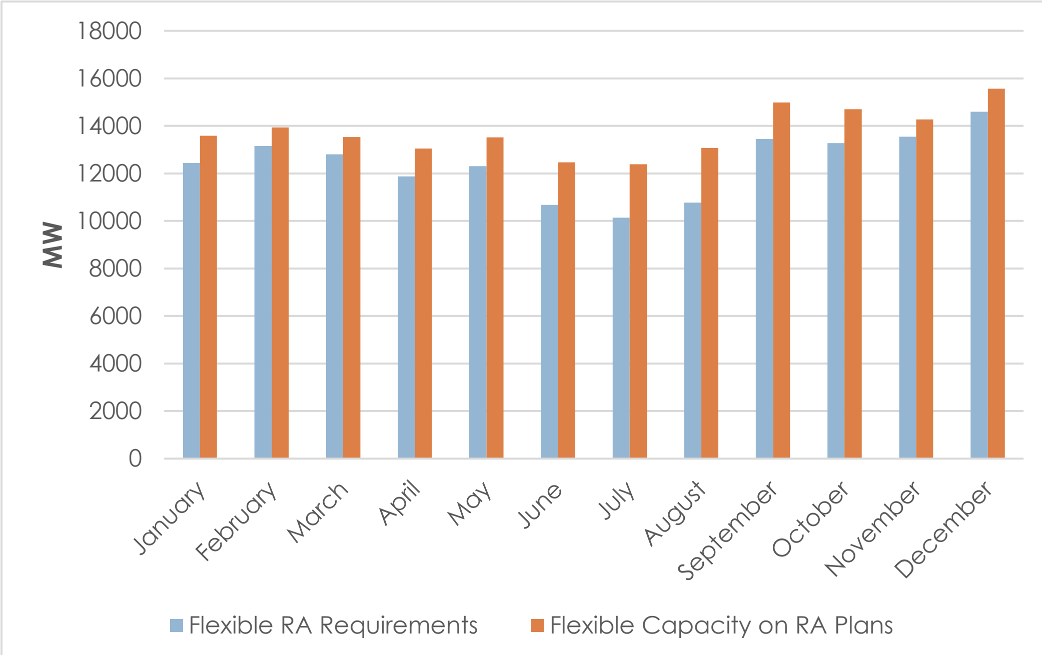
In the allocation cycle for 2019, LSEs submitted revised June-December forecasts to the CEC on March 17, 2019. After reviewing these values, the CEC revised the August load shares. Energy Division used the revised load shares to recalculate individual LSE local requirements, which were then sent to LSEs on April 12, 2019. 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.

2.4 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.[16] 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 2019.

[16] 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 2019, CPUC-Jurisdictional LSEs



Source: 2019 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 2018 and 2019 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. Data used in this analysis were restricted to contracts executed in 2018 or 2019 for delivery in 2019. The final data set consisted of 3,766 monthly contract values.

3.1.1 System Capacity Prices

Table 6 provides a summary of 2019 capacity prices.

Table 6. 2019 Capacity Prices

	2019 Capacity
Contracted Capacity (MW)	97,527
Percentage of total contracted MW in dataset	18%
Weighted Average Price ($/kW-month)	$3.46
Average Price ($/kW-month)	$3.63
Minimum Price ($/kW-month)	$0.12
Maximum Price ($/kW-month)	$15.25
85% of MW at or below ($/kW-month)	$4.93

Source: 2019 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 2020 Net Qualifying Capacity list is used to identify resources' local area and Path 26 zone.[17]

[17] The 2020 Net Qualifying Capacity list can be found at https://www.cpuc.ca.gov/General.aspx?id=6311.

The data set represents 111,052 MW-months of capacity under contract. Of that capacity, 45 percent is located in the NP-26 zone, and 42 percent is located SP-26[18] and 12 percent is comprised of capacity imports to CAISO. The data set also shows that 71 percent of the total capacity is located in local areas, with the remaining 17 percent located in the CAISO System area.

The weighted average price for all capacity is $3.26/kW-month. The weighted average price for SP-26 capacity (including local and system RA) is $3.40/kW-month, which is about 3 percent lower than the NP-26 weighted average price of $3.51/kW-month.

The weighted average prices of local and system RA capacity are both $3.46/kW-month. System and local RA prices appear to be converging. The premium for local RA has decreased rapidly over that 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, and 7 percent in the 2019 report indicating that the market for system RA has tightened.

[18] Path 26 is defined in the WECC Path Rating Catalog, viewable at https://www.wecc.biz/Reliability/NDA/WECC_2016_Path_Rating_Catalog.pdf.

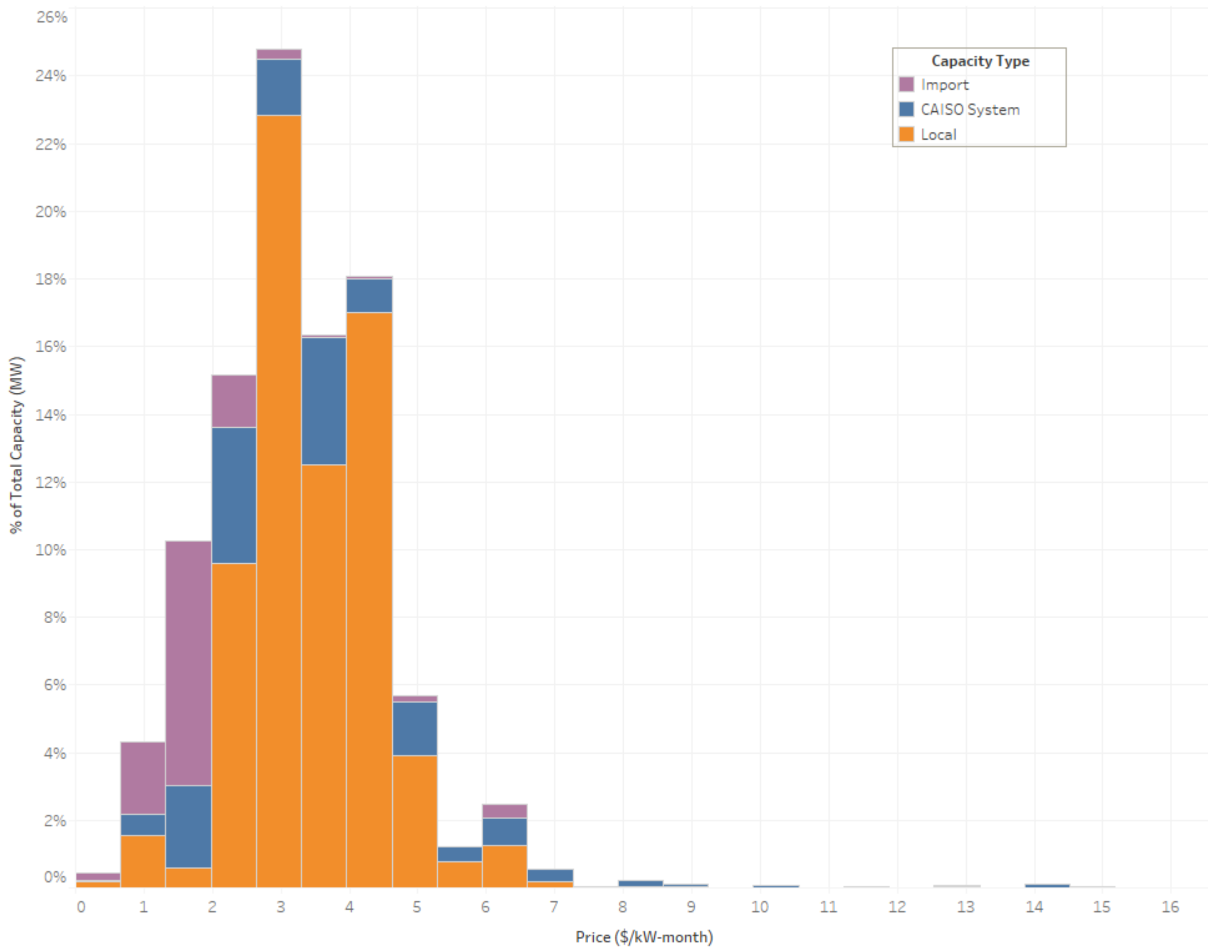
Table 7. Aggregated RA Contract Prices, 2019

	All RA				Local RA			CAISO System RA		
	Total	NP-26	SP-26	Import	**Subtotal**	NP26	SP26	**Subtotal**	NP26	SP26
Contracted Capacity (MW)	**111,052**	50,518	47,008	13,525	**78,394**	42,346	36,048	**19,133**	8,172	10,961
Percentage of Total Capacity in Data Set	**100%**	45%	42%	12%	**71%**	38%	32%	**17%**	7%	10%
Number of Monthly Values	**4,107**	2,183	1,583	341	**2,733**	1,688	1,045	**1,033**	495	538
Weighted Average Price ($/kW-month)	**$3.26**	$3.51	$3.40	$1.83	**$3.46**	$3.36	$3.57	**$3.46**	$4.29	$2.85
Average Price ($/kW-month)	**$3.49**	$3.91	$3.25	$1.91	**$3.58**	$3.66	$3.46	**$3.77**	$4.78	$2.83
Minimum Price ($/kW-month)	**$0.12**	$0.75	$0.12	$0.18	**$0.35**	$0.75	$0.35	**$0.12**	$0.95	$0.12
Maximum Price ($/kW-month)	**$15.25**	$15.25	$8.00	$6.50	**$15.25**	$15.25	$6.66	**$14.60**	$14.60	$8.00
85% of MW at or below ($/kW-month)	**$4.75**	$5.75	$4.25	$2.25	**$4.50**	$5.00	$4.25	**$6.50**	$9.00	$4.00

Source: 2019-2023 price data submitted by LSEs.

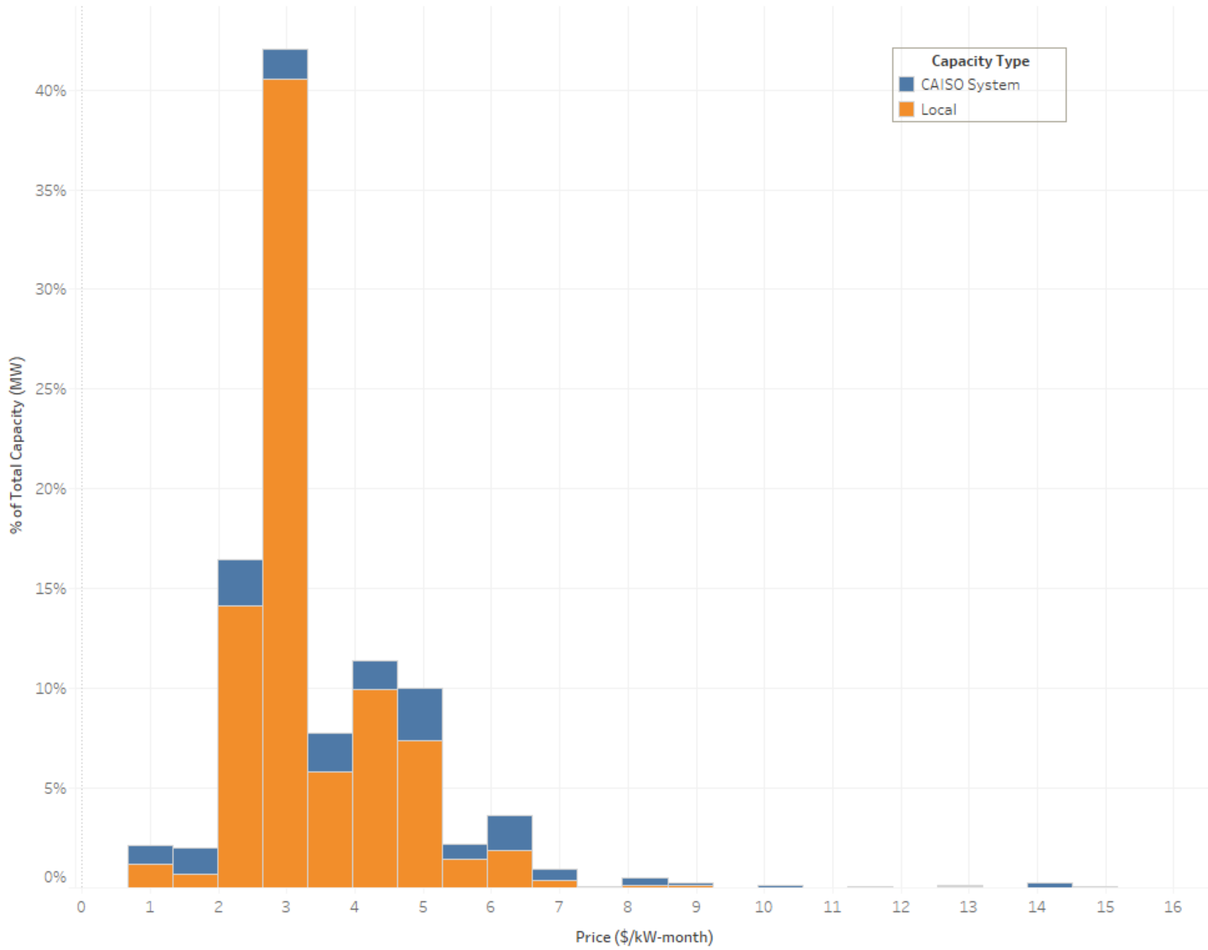
The price distribution of RA-only contracts for 2019 is shown in Figure 5, Figure 6, and Figure 7. These figures underscore the high percentage of RA contracts that are for local capacity.

Figure 5. Price Distribution for RA Capacity Contracts, 2019 Compliance Year



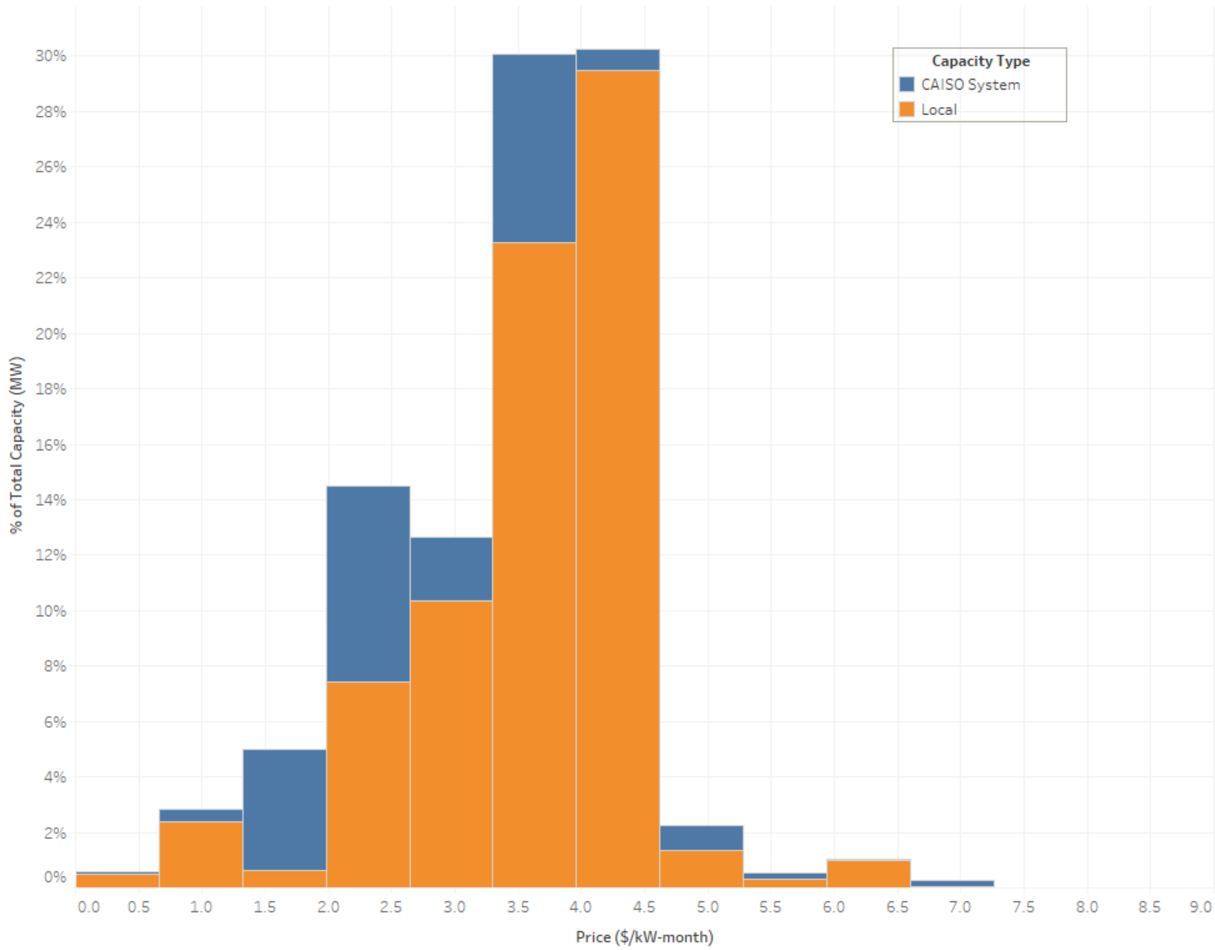
Source: 2019 price data submitted by LSEs.

Figure 6. Price Distribution for RA Capacity Contracts North of Path 26, 2019



Source: 2019 price data submitted by LSEs.

Figure 7. Price Distribution for RA Capacity Contracts South of Path 26, 2019



Source: 2019 price data submitted by the 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 are shown in Table 8 below.

Table 8. RA Capacity Prices by Month and Path 26 Zone, 2019

	Path 26 Zone	Contracted Capacity (MW)	Percentage of Total Capacity in Data Set	Weighted Average Price ($/kW-month)	Average Price ($/kW-month)	Minimum Price ($/kW-month)	Maximum Price ($/kW-month)	85th Percentile ($/kW-month)
	North	3,403	3.49%	$2.93	$3.07	$0.95	$5.65	$4.00
Jan	South	3,691	3.78%	$3.26	$2.99	$0.35	$4.75	$4.18
	Total	7,094	7.27%	$3.10	$3.03	$0.35	$5.65	$4.11
	North	3,491	3.58%	$2.96	$3.06	$0.95	$5.65	$4.00
Feb	South	4,250	4.36%	$3.10	$2.91	$0.35	$4.75	$4.15
	Total	7,741	7.94%	$3.04	$2.99	$0.35	$5.65	$4.01
	North	3,228	3.31%	$2.94	$3.02	$0.95	$6.00	$4.00
Mar	South	3,370	3.46%	$3.41	$3.02	$1.15	$4.75	$4.15
	Total	6,597	6.76%	$3.18	$3.02	$0.95	$6.00	$4.02
	North	3,039	3.12%	$3.02	$3.13	$0.95	$6.00	$4.00
Apr	South	3,947	4.05%	$3.21	$2.97	$0.35	$6.70	$4.10
	Total	6,986	7.16%	$3.13	$3.05	$0.35	$6.70	$4.00
	North	3,785	3.88%	$3.09	$3.22	$1.00	$6.66	$4.00
May	South	4,509	4.62%	$3.17	$3.05	$1.25	$6.66	$4.11
	Total	8,293	8.50%	$3.13	$3.14	$1.00	$6.66	$4.00
	North	4,416	4.53%	$3.62	$3.91	$1.00	$7.00	$5.50
Jun	South	4,401	4.51%	$3.37	$3.13	$0.12	$6.70	$4.15
	Total	8,817	9.04%	$3.49	$3.59	$0.12	$7.00	$5.00
	North	5,070	5.20%	$3.97	$4.32	$1.00	$13.00	$6.45
Jul	South	3,932	4.03%	$3.77	$3.50	$1.50	$6.70	$4.71
	Total	9,002	9.23%	$3.89	$4.02	$1.00	$13.00	$6.00
	North	5,883	6.03%	$4.10	$4.45	$1.00	$9.50	$6.50
Aug	South	3,919	4.02%	$3.77	$3.53	$1.25	$6.90	$4.75
	Total	9,803	10.05%	$3.97	$4.12	$1.00	$9.50	$6.00
Sep	North	5,513	5.65%	$4.38	$5.94	$1.00	$15.25	$9.00
	South	3,951	4.05%	$3.67	$4.37	$1.50	$8.00	$8.00

	Path 26 Zone	Contracted Capacity (MW)	Percentage of Total Capacity in Data Set	Weighted Average Price ($/kW-month)	Average Price ($/kW-month)	Minimum Price ($/kW-month)	Maximum Price ($/kW-month)	85th Percentile ($/kW-month)
	Total	9,463	9.70%	$4.08	$5.40	$1.00	$15.25	$9.00
Oct	North	4,980	5.11%	$3.62	$3.71	$0.75	$7.45	$5.25
	South	3,740	3.84%	$3.48	$3.12	$1.15	$5.50	$4.10
	Total	8,720	8.94%	$3.56	$3.47	$0.75	$7.45	$4.65
Nov	North	4,358	4.47%	$3.25	$3.24	$0.95	$7.45	$4.53
	South	3,810	3.91%	$3.42	$3.05	$1.00	$4.75	$4.10
	Total	8,167	8.37%	$3.33	$3.16	$0.95	$7.45	$4.18
Dec	North	3,353	3.44%	$2.99	$3.27	$0.95	$7.45	$4.10
	South	3,491	3.58%	$3.21	$3.08	$0.75	$4.75	$4.18
	Total	6,843	7.02%	$3.10	$3.19	$0.75	$7.45	$4.15

Source: 2019 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. 2019 Weighted average prices for local areas range from $3.10/kW-month in Fresno to $5.63/kW-month in Humboldt, while 85th percentile prices ranged from $4.00/kW-month in the Bay Area and Big Creek/Ventura to $7.85/kW-month in North Coast/North Bay. These are significant increases over prices reported in prior years.

Table 9. Capacity Prices by Local Area, 2019

	Contracted Capacity (MW)	Percentage of Total Capacity in Data Set	Weighted Average Price ($/kW-month)	Average Price ($/kW-month)	Minimum Price ($/kW-month)	Maximum Price ($/kW-month)	85% of MW at or below ($/kW-month)
CAISO System	19,133	20%	$3.46	$3.77	$0.12	$14.60	$6.50
LA Basin	22,879	23%	$3.80	$3.68	$0.75	$13.00	$4.64
Big Creek-Ventura	12,347	13%	$3.63	$3.33	$0.35	$15.25	$4.00
San Diego-IV	4,788	5%	$3.46	$3.80	$1.00	$12.95	$4.50
Bay Area	26,974	28%	$3.14	$3.42	$0.95	$14.60	$4.00
Fresno	4,218	4%	$3.10	$3.31	$1.00	$8.50	$5.00
Humboldt	206	0%	$5.63	$5.46	$2.90	$6.50	$6.45
Kern	92	0%	$3.97	$4.05	$2.00	$6.00	$6.00
NCNB	917	1%	$4.28	$5.08	$3.00	$13.50	$7.85
Sierra	5,881	6%	$3.22	$3.30	$2.25	$9.00	$4.50
Stockton	54	0%	$4.05	$4.03	$2.00	$6.45	$5.65
PG&E Unspecified Local	39	0%	$3.63	$3.77	$1.72	$7.00	$5.20

Source: 2019 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 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, 2019

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CAISO System	**Weighted Average**	$2.26	$2.24	$2.19	$2.37	$2.83	$3.42	$4.19	$4.44	$5.01	$3.33	$2.63	$2.82
	85th Percentile	$2.66	$2.80	$2.83	$3.50	$3.50	$4.50	$6.00	$6.00	$9.00	$4.65	$3.56	$3.53
LA Basin	**Weighted Average**	$3.81	$3.38	$3.73	$3.83	$3.38	$3.88	$4.10	$4.12	$4.15	$3.91	$3.93	$3.65

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	85th Percentile	$4.25	$4.20	$4.25	$4.25	$4.26	$4.65	$4.75	$4.75	$4.66	$4.25	$4.25	$4.24
Big Creek-Ventura	Weighted Average	$2.48	$2.62	$3.31	$2.63	$3.23	$3.06	$4.08	$4.22	$4.14	$3.99	$3.93	$3.08
	85th Percentile	$4.00	$4.00	$4.00	$4.00	$4.00	$4.00	$4.50	$5.17	$4.23	$4.00	$4.00	$4.01
San Diego-IV	Weighted Average	$3.38	$3.31	$3.40	$3.39	$3.41	$3.42	$3.42	$3.44	$3.55	$3.98	$3.41	$3.40
	85th Percentile	$4.45	$4.45	$4.50	$4.50	$4.50	$4.65	$4.53	$4.74	$5.95	$4.70	$4.50	$4.50
Bay Area	Weighted Average	$2.91	$2.95	$3.07	$3.13	$3.09	$3.19	$3.38	$3.36	$3.28	$3.19	$3.09	$3.00
	85th Percentile	$4.00	$4.00	$4.00	$4.00	$4.00	$4.20	$5.25	$5.25	$4.64	$4.15	$4.00	$4.00
Fresno	Weighted Average	$3.07	$3.05	$2.57	$2.73	$2.94	$3.98	$3.35	$3.09	$3.99	$2.97	$2.67	$2.70
	85th Percentile	$3.12	$3.00	$2.90	$3.57	$3.51	$5.97	$5.92	$5.92	$6.05	$3.57	$3.93	$4.01
Humboldt	Weighted Average	$2.90	$2.90		$5.50	$5.50	$5.50	$6.08	$6.15	$5.50	$5.63	$5.50	$5.50
	85th Percentile	$2.90	$2.90		$5.50	$5.50	$5.50	$6.45	$6.50	$5.50	$5.93	$5.50	$5.50
Kern	Weighted Average		$2.00	$6.00	$2.28	$5.11	$6.00	$6.00	$6.00	$6.00	$6.00	$2.00	$6.00
	85th Percentile		$2.00	$6.00	$3.60	$5.55	$6.00	$6.00	$6.00	$6.00	$6.00	$2.00	$6.00
NCNB	Weighted Average	$3.54	$3.75	$3.66	$3.52	$3.90	$4.77	$5.68	$5.10	$5.17	$4.39	$3.62	$3.84
	85th Percentile	$4.50	$4.50	$4.50	$4.00	$6.00	$7.00	$8.04	$8.05	$12.95	$6.00	$4.75	$4.75
Sierra	Weighted Average	$3.00	$3.09	$3.11	$2.69	$2.75	$3.56	$3.89	$3.66	$3.07	$3.73	$2.70	$2.82
	85th Percentile	$4.30	$3.40	$3.65	$3.26	$3.49	$6.25	$6.45	$5.75	$4.33	$5.45	$3.26	$3.40
Stockton	Weighted Average	$3.40	$3.45	$4.24	$4.11	$3.49	$3.03	$3.23	$2.35	$2.12	$6.13	$4.30	$3.65
	85th Percentile	$5.16	$5.16	$5.16	$5.53	$5.16	$5.16	$5.16	$2.35	$2.30	$6.45	$5.16	$5.16

Source: 2018 price data submitted by LSEs.

3.1.3 Flexible Capacity Prices

Table 11 describes capacity prices for CAISO resources located outside of local areas. As seen in previous years, prices for flexible capacity are not higher than those for system capacity. The 2019 weighted average price for flexible capacity is $2.79/kW-month while it is $3.46/kW-month for system capacity.

Table 11. Aggregated Non-Local RA Contract Prices Excluding Imports, 2019

	Flexible Capacity	Non-Flexible Capacity	All CAISO System
Contracted Capacity (MW)	7,531	11,601	19,133
Percentage of Total Capacity in Data Set	39%	61%	100%
Weighted Average Price ($/kW-month)	$2.79	$3.46	$3.46
Average Price ($/kW-month)	$2.59	$3.77	$3.77
Minimum Price ($/kW-month)	$0.75	$0.12	$0.12
Maximum Price ($/kW-month)	$7.25	$14.60	$14.60
85% of MW at or below ($/kW-month)	$4.00	$6.50	$6.50

Source: 2019 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. 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 Commission,[19] 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.[20]

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.

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;
- 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

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

[20] Dynegy Oakland

- Cumulative flexible capacity deficiency in an annual or monthly RA plans.[21]

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.[22] The Competitive Solicitation Process applies to all potential CPM designations. Table 12 shows CAISO's CPM designations for 2019.

---

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

[22] 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 2019

Resource ID	County	MW	CPM Type	Term (days)	Start Date	End Date	Est. Cap. Cost /kW-mth	Total Cost
HUMBPP_1_UNITS3	Humboldt	15	Local Reliability Issue	60	7/15/2019	9/13/2019	$6.31	$189,300
HUMBPP_6_UNITS	Humboldt	48.73	Local Reliability Issue	60	7/5/2019	9/3/2019	$6.31	$614,973
CSCGNR_1_UNIT 1	Santa Clara	7.95	Local Reliability Issue	60	5/23/2019	7/22/2019	$6.31	$59,630
DUANE_1_PL1X3	Santa Clara	130.1	Local Reliability Issue	60	5/23/2019	7/22/2019	$6.31	$1,158,516

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 Commission 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 Commission 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 community choice aggregator customers. 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 2019 CAM resources. The list includes all conventional generation resources subject to the CAM mechanism since its inception. 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 2019

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
ETIWND_6_GRPLND	7/17/2007	UOG	SCE	46
BARRE_6_PEAKER	7/19/2007	UOG	SCE	47
MIRLOM_6_PEAKER	7/19/2007	UOG	SCE	46
CENTER_6_PEAKER	7/20/2007	UOG	SCE	47
BARRE_6_PEAKER	8/1/2007	UOG	SCE	47
MNDALY_6_MCGRTH	8/1/2009	UOG	SCE	47.2
BUCKBL_2_PL1X3	8/1/2010	7/31/2020	SCE	490
VESTAL_2_WELLHD	1/16/2013	1/15/2023	SCE	49
COCOPP_2_CTG1	5/1/2013	4/30/2023	PG&E	200.3
COCOPP_2_CTG2	5/1/2013	4/30/2023	PG&E	199.7
COCOPP_2_CTG3	5/1/2013	4/30/2023	PG&E	199
COCOPP_2_CTG4	5/1/2013	4/30/2023	PG&E	199.7
WALCRK_2_CTG1	6/1/2013	5/31/2023	SCE	96
WALCRK_2_CTG2	6/1/2013	5/31/2023	SCE	96
WALCRK_2_CTG3	6/1/2013	5/31/2023	SCE	96
WALCRK_2_CTG4	6/1/2013	5/31/2023	SCE	96
WALCRK_2_CTG5	6/1/2013	5/31/2023	SCE	96.65
ELSEGN_2_UN1011	8/1/2013	7/31/2023	SCE	263
ELSEGN_2_UN2021	8/1/2013	7/31/2023	SCE	263.68
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
ESCNDO_6_PL1X2	5/1/2014	12/31/2039	SDG&E	48.71
ELKHIL_2_PL1X3	1/1/2016	12/31/2020	SCE	200
CHINO_2_APEBT1	12/31/2016	12/30/2026	SCE	20
ELCAJN_6_EB1BT1	02/21/2017	12/30/2099	SDG&E	7.5

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
ESCNDO_6_EB1BT1	03/06/2017	12/30/2099	SDG&E	10
ESCNDO_6_EB2BT2	03/06/2017	12/30/2099	SDG&E	10
ESCNDO_6_EB3BT3	03/06/2017	12/30/2099	SDG&E	10
PIOPIC_2_CTG1	6/1/2017	12/31/2037	SDG&E	106
PIOPIC_2_CTG2	6/1/2017	12/31/2037	SDG&E	106
PIOPIC_2_CTG3	6/1/2017	12/31/2037	SDG&E	106
MIRLOM_2_MLBBTA	7/1/2017	6/30/2027	SCE	10
MIRLOM_2_MLBBTB	7/1/2017	6/30/2027	SCE	10
SANTGO_2_MABBT1	10/1/2017	12/31/2026	SCE	2
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
GOLETA_6_ELLWOD	1/1/2019	12/31/2020	SCE	54
ORMOND_7_UNIT 2	1/1/2019	12/31/2020	SCE	750
TOTAL				**5430.53**

*NQC values are from the year the resource is listed under. NQC values can change monthly and annually.

3.4.2 QF/CHP Resources

D.10-12-035[23] 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.[24] 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,

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

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

including bundled, ESP, and CCA customers. The RA benefits associated with the CHP contract are also allocated to all customers paying the net capacity costs.[25] Table 14 below lists the CHP resources whose RA capacity was allocated as of 2019.

Table 14. 2019 CHP Resources Allocated for CAM as of 2019

Scheduling Resource ID	CAM Start Date	CAM End Date	August NQC*	Authorized IOU
KERNFT_1_UNITS	4/1/2012	11/30/2020	47	PG&E
SIERRA_1_UNITS	4/1/2012	11/30/2020	47	PG&E
DOUBLC_1_UNITS	4/1/2012	11/30/2020	47	PG&E
TANHIL_6_SOLART	12/1/2019	11/30/2026	9.92	PG&E
FRITO_1_LAY	11/1/2019	10/31/2026	0.08	PG&E
KERNRG_1_UNITS	10/1/2019	9/30/2026	0.2	PG&E
CALPIN_1_AGNEW	11/1/2012	4/18/2021	28	PG&E
OROVIL_6_UNIT	1/1/2014	10/14/2020	7.5	PG&E
OMAR_2_UNIT 1	1/1/2014	12/31/2020	77.25	PG&E
OMAR_2_UNIT 2	1/1/2014	12/31/2020	77.25	PG&E
OMAR_2_UNIT 3	1/1/2014	12/31/2020	77.25	PG&E
OMAR_2_UNIT 4	1/1/2014	9/30/2020	77.25	PG&E
LMEC_1_PL1X3	1/1/2014	12/31/2021	135	SCE
GILROY_1_UNIT	1/1/2014	12/31/2018	52.5	SCE
SYCAMR_2_UNIT 1	1/1/2014	12/31/2021	56.53	SCE
SYCAMR_2_UNIT 2	1/1/2014	12/31/2021	56.54	SCE
SYCAMR_2_UNIT 3	1/1/2014	12/31/2021	56.53	SCE
SYCAMR_2_UNIT 4	1/1/2014	12/31/2021	56.53	SCE
STOILS_1_UNITS	10/1/2014	7/31/2026	1.72	PG&E
SMPRIP_1_SMPSON	4/1/2015	5/31/2018	45.6	PG&E
BEARMT_1_UNIT	5/1/2015	4/30/2022	44.58	PG&E
SUNSET_2_UNITS	7/1/2015	12/31/2020	218	PG&E
BDGRCK_1_UNITS	5/1/2015	4/30/2022	36.29	PG&E
CHALK_1_UNIT	5/1/2015	4/30/2022	36.53	PG&E
MKTRCK_1_UNIT 1	5/1/2015	4/30/2022	35.96	PG&E
LIVOAK_1_UNIT 1	5/1/2015	4/30/2022	41.14	PG&E
TIDWTR_2_UNITS	7/1/2015	4/30/2022	22.75	PG&E
CHEVMN_2_UNITS	7/10/2014	12/31/2050	6.2	SCE

[25] 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."

Scheduling Resource ID	CAM Start Date	CAM End Date	August NQC*	Authorized IOU
ARCOGN_2_UNITS	7/1/2015	6/30/2022	260.33	SCE
UNVRSY_1_UNIT 1	7/1/2015	6/30/2022	34.87	SCE
ETIWND_2_UNIT1	1/1/2016	12/31/2022	16.88	SCE
HINSON_6_CARBGN	6/1/2017	5/31/2021	29.56	SCE
HOLGAT_1_BORAX	7/1/2015	6/30/2022	13.66	SCE
TENGEN_2_PL1X2	7/1/2014	6/30/2021	37.62	SCE
SNCLRA_2_UNIT1	4/1/2016	3/30/2023	17.54	SCE
SNCLRA_2_UNIT	4/12/2018	3/31/2020	24.49	SCE
SAMPSN_6_KELCO1	6/1/2017	6/2/2022	3.27	SDGE
CHINO_6_CIMGEN	3/11/2018	3/10/2025	25.96	SCE
DEXZEL_1_UNIT	12/1/2015	3/31/2022	18.65	PG&E
ELKHIL_2_PL1X3	1/1/2016	12/31/2020	200	SCE
GRZZLY_1_BERKLY	8/1/2017	7/31/2024	24.57	PG&E
SNCLRA_2_HOWLNG	4/1/2017	10/31/2023	7.63	SCE
VESTAL_2_UNIT1	4/1/2017	3/31/2026	2.93	SCE
TOTAL			**2116.06**	

*NQC values are from the year the resource is listed under. 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 for delivery in 2016 and 2017. The pilot was later extended to 2018 and 2019. 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 2019.

Table 15. 2019 DRAM Capacity Allocated for CAM

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
Multiple	1/1/2019	12/31/2019	PG&E	162.75
Multiple	1/1/2019	12/31/2019	SCE	176.04
Multiple	1/1/2019	12/31/2019	SDG&E	34.74
			TOTAL	**373.53**

*NQC values can vary by month.

Event-based DR resources are market-integrated and 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, direct access, and community choice aggregator customers. 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 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 shows the total DR, CAM, and RMR credits allocated by TAC area from 2008 to 2020.

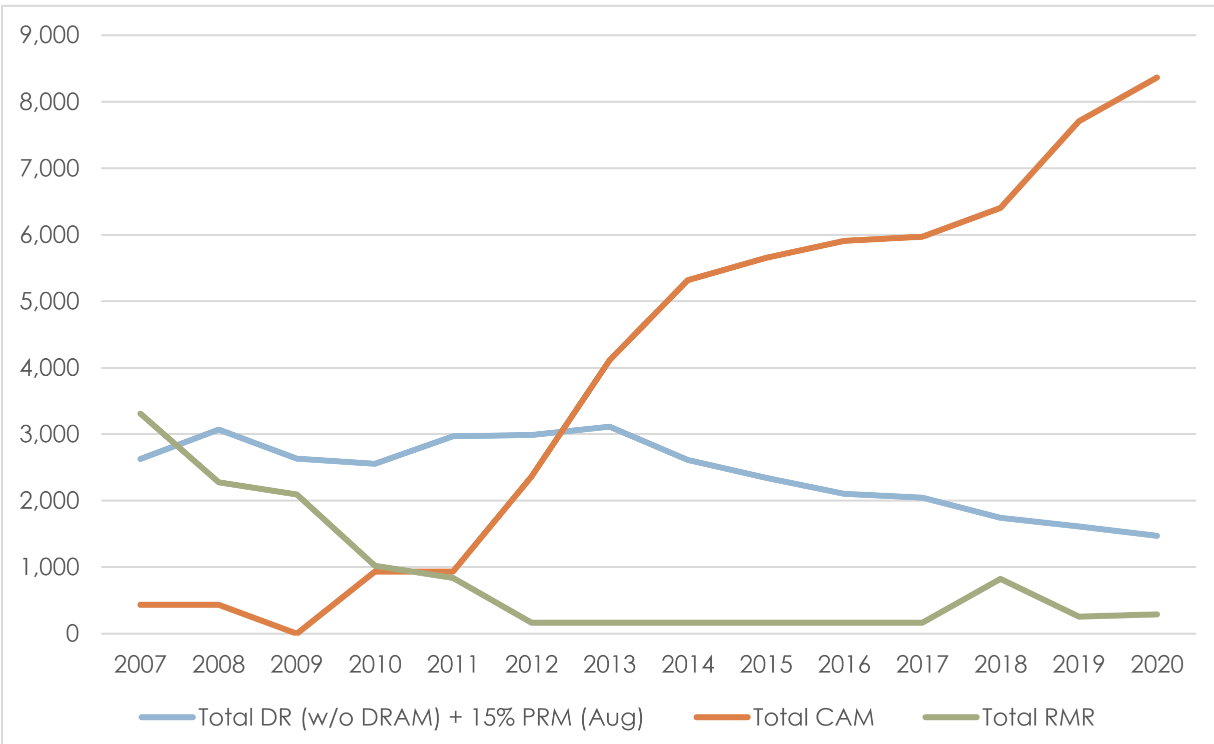
Figure 8 below illustrate the amounts and types of procurement credit that have been allocated since the beginning of the RA program. The graph reflects the decline in RMR units until 2018 and the increase in CAM units. DR RA credits have declined slightly since 2013. The total amount of capacity procured through DR, CAM, and RMR for August 2019 was 9,832 MW. This is about 20 percent of the total CPUC-jurisdictional LSE obligation for August 2019 (47,882 MW). In August 2019, total CAM procurement reached 7,706 MW whereas RMR procurement decreased from 826 MW in 2018 to 256 MW in 2019.

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	5,535
	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

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
	Total CAM (Aug)	**436**	**436**	**936**	**936**	**2,362**	**4,114**	**5,316**	**5,652**	**5,905**	**5,969**	**6,401**	**7,706**	**8,363**
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**

Figure 8. RA Procurement Credit Allocation, 2006 – 2019 (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[26] 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.[27]

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 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 exceeds the resource's deliverable capacity, the NQC is adjusted to the deliverable capacity value. The CAISO conducts deliverability assessments for both new and existing resources two to three times a year pursuant to the Large Generator Interconnection Procedures (LGIP).

---

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

[27] https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442455533.

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 2019

A total of 650 MW of capacity retired in 2019 including the 493 MW Redondo Unit 7. While this was partially offset by 392 MW of new resources, overall 2019-2020 saw a decrease in available capacity.

Table 17 and Table 18 list the new and retiring facilities for 2019. Net dependable capacity, the amount of deliverable capacity as determined by the CAISO, is also listed for new facilities. Generators are increasingly coming 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 2019, the net dependable capacity of new facilities was about 1,505 MW which was over three times greater than the assigned NQC values.

Table 17. New NQC Resources Online in 2019

Resource ID	Resource Name	Technology	NQC	Net Dependable Capacity
BGSKYN_2_ASPSR2	Antelope Solar 2 San Pablo	Solar PV	27	100
BGSKYN_2_BS3SR3	Big Sky Solar 3	Solar PV	5.4	20
CALFTS_2_CFSSR1	California Flats Solar South	Solar PV	40.5	150
DAIRLD_1_MD2BM1	Madera Digester Genset 2	Biogas	0	0.8
DSFLWR_2_WS2SR1	Willow Springs 2	Solar PV	27	100
FRNTBW_6_SOLAR1	Frontier Solar	Solar PV	5.4	20
IVSLR2_2_SM2SR1	Silver Ridge Mount Signal 2	Solar PV	40.5	150
RATSKE_2_NROSR1	North Rosamond Solar	Solar PV	40.5	150
RECTOR_2_TFDBM1	Two Fiets Dairy Digester	Biogas	0	0.8
REDMAN_6_AVSSR1	Antelope Valley Solar	Solar PV	0.81	3
RNDSBG_1_HZASR1	Hazel A	Solar PV	0.81	2.99
SANLOB_1_OSFBM1	HZIU Kompogas SLO	Biogas	0	0.85

SCHNDR_1_OS2BM2	Open Sky Digester Genset 2	Biogas	0	0.8
SLRMS3_2_SRMSR1	SILVER RIDGE MOUNT SIGNAL 3	Solar PV	67.5	250
STROUD_6_WWHSR1	Winter Wheat Solar Farm	Solar PV	0	1.5
SUNSLR_1_SSVSR1	Sunshine Valley Solar 1	Solar PV	22.95	100
SUNSPT_2_WNASR1	Windhub Solar A	Solar PV	5.4	20
TX-ELK_6_ECKSR2	Eagle Creek	Solar PV	0	3
VALTNE_2_AVASR1	Valentine Solar	Solar PV	27	100
VOYAGR_2_VOYWD 1	Voyager 1	Wind	27.53	131.1
WRGTSR_2_WSFSR1	Wright Solar Freeman	Solar PV	54	200
		Total	**392.3**	**1504.84**

Source: 2019-2020 NQC lists posted to the CAISO website.[28]

Table 18. Resources Retired in 2019

Resource ID	Resource Name	Technology	NQC	Status
CHINO_6_SMPPAP	AltaGas Pomona Energy	Cogeneration	22.78	Retired
DINUBA_6_UNIT	Dinuba Energy, Inc.	Biomass	4.07	Mothballed
GOLETA_6_GAVOTA	Point Arguello Pipeline Company	Cogeneration	0	Retired
GRNLF1_1_UNITS	Greenleaf 1	Cogeneration	49.2	Retired
KANAKA_1_UNIT	Kanaka	Hydro	0.64	Retired
KRAMER_1_KJ5SR5	Kramer Junction 5	Solar Thermal	13.44	Retired
KRAMER_1_SEGSR3	Kramer Junction 3	Solar Thermal	13.44	Retired
KRAMER_1_SEGSR4	Kramer Junction 4	Solar Thermal	13.44	Retired
KRAMER_1_SEGSR6	Luz Solar Partners Ltd., VI, LP	Solar Thermal	15.68	Retired
KRAMER_1_SEGSR7	Luz Solar Partners Ltd., VII, LP	Solar Thermal	15.68	Retired
OTAY_6_LNDFL5	Otay 5	Biogas	0	Retired
OTAY_6_LNDFL6	Otay 6	Biogas	0	Retired
OTAY_6_UNITB1	Otay Landfill Units Aggregate	Biogas	2.13	Retired
PTLOMA_6_NTCCGN	AEI MCRD Steam Turbine	Cogeneration	2.46	Retired
REDOND_7_UNIT 7	Redondo Gen Sta. Unit 7	Steam Turbine	493.24	Retired
SAUGUS_2_TOLAND	Toland Landfill gas to Energy Project	Biogas	0	Retired
VALLEY_5_RTS044	North Island QF	Solar PV	3.58	Retired

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

Total	**649.78**

Source: CAISO Announced Retirement and Mothball list.[29]

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.[30]

4.2 Aggregate NQC Values 2015 through 2020

Table 19 shows aggregate NQC values from the CAISO NQC lists for 2015 through 2020.[31] The total 2020 NQC (as reported on the CAISO NQC list) increased by 560 MW from the 2019 NQC list. The number of resources on the NQC list continued to grow as demand response resources were integrated into the CAISO market. There also may be a change in NQC for facilities that began operation in the previous year, but not in time to receive an August NQC value or for facilities that come online in phases and receive an initial NQC value for partial capacity.

Table 19. Final NQC Values for 2015-2020

Year	Total NQC (MW)	Total Number of Scheduling Resource IDs	Net NQC Change (MW)	Net Gain in CAISO IDs on List
2015	52,996	802	-	-
2016	53,173	972	177	170
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
2015-20			**-4,007**	**1,159**

Source: NQC lists from 2015 through 2020.

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

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

[31] 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.

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 2019 compliance year. The workshop, RA guide, and templates were designed to assist LSEs in demonstrating compliance with the RA program.

The final 2019 filing guide[32] and templates were made available to LSEs in September 2018. Changes were made to implement the new RA rules adopted in D.18-06-030. 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,
- Confirming compliance with local area and Path 26 requirements[33],
- Verifying matching supply plans, and;
- Requesting corrections from LSEs.

[32] See https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442459140.

[33] The Path 26 requirement was removed in June 2019 with Commission approval of D.19-06-26.

A crucial step in this process relies on CAISO collection and organization of supply plans submitted by scheduling coordinators for generators. Energy Division verifies 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 2019 Compliance Years

Pursuant to Commission Resolution E-4195,[34] 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 Commission.

Table 20 summarizes enforcement actions and citations taken by the Commission since 2012. From 2012 through 2019, the Commission issued 61 citations for violations and took no enforcement action, for a total penalty of $15,241,944. In 2018, ten citations were

---

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

issued for penalties of $2,596,739. In 2019, twenty-six citations were issued for penalties of $9,553,046.[35]

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

Compliance Year	Citations Issued	LSEs Cited	Citation Penalties	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

[35] For a list of all penalties, please see: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Utility_Enforcement/UEB%20Energy%20Citations%20--%20Updated%20Oct%2007%202020.pdf

For waivers, please see: https://www.cpuc.ca.gov/General.aspx?id=6442465461

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)**	**$9,553,046**	**0**	**0**	**0**
Total	**61**		**$15,241,944**	**0**	**0**	**0**

6 APPENDIX

2019 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 Solana Beach / Solana Energy Alliance
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. Agera Energy LLC
19. Lancaster Choice Energy
20. Liberty Power Holdings, LLC
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