The 2017
Resource Adequacy Report

ENERGY DIVISION

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August 2018

2017 Resource Adequacy Report

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AS	Ancillary Services	LCR	Local Capacity Requirement
		LD	Liquidated Damages
BCR	Bid Cost Recovery	LI	Load Impact
CAISO	California Independent System Operator	LOLP	Loss of Load Probability
CAM	Cost-Allocation Mechanism	LSE	Load Serving Entity
CCGT	Combined Cycle Gas Turbine	MCC	Maximum Cumulative Capacity
CEC	California Energy Commission	MOO	Must Offer Obligation
DA	Direct Access	MW	Megawatt
DASR	Direct Access Service Request	NCF	Net Capacity Factor
DG	Distributed Generation	NDC	Net Dependable Capacity
DR	Demand Response	NERC	North American Reliability Corporation
DSM	Demand Side Management	NQC	Net Qualifying Capacity
EAF	Equivalent Availability Factor	PRM	Planning Reserve Margin
ED	Energy Division	QC	Qualifying Capacity
EFORd	Equivalent Forced Outage Rate of demand	QF	Qualifying Facility
ELCC	Effective Load Carrying Capacity	RA	Resource Adequacy
EFC	Effective Flexible Capacity	RAR	Resource Adequacy Requirement
ERRA	Energy Resource Recovery Account	RMR	Reliability Must Run
ESP	Electricity Service Provider	RPS	Renewable Portfolio Standard
ETC	Existing Transmission Contract	SCP	Standard Capacity Product
FERC	Federal Energy Regulatory Commission	SFTP	Secure File Transfer Protocol
FOH	Forced Outage Hours	TAC	Transmission Access Charge
HE	Hour Ending	TCPM	Transitional Capacity Procurement Mechanism
ICPM	Interim Capacity Procurement Mechanism	TIC	Total Installed Capacity
IOU	Investor Owned Utility	ULR	Use Limited Resources

1 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% 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 annual and monthly system, local, and flexible RA requirements for CPUC-jurisdictional LSEs are set by the CPUC; they reflect both transmission constraints and LSE load share.

This report provides a review of the CPUC's RA program, summarizing RA program experience during the 2017 RA compliance year. While this report does not make explicit policy recommendations, it is intended to provide information relevant to the currently open RA rulemaking (R.17-09-020) and ongoing implementation of the RA program in California.

Each October, the RA program requires LSEs to make an annual system and local compliance showings for the coming year. For the system showing, LSEs are required to demonstrate that they have procured 90% of their system RA obligation for the five summer months. For the local showing, LSEs are required to demonstrate that they have procured 100% of their local RA obligation for all twelve months. Starting 2016, LSEs are required to demonstrate that they have procured 90% 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% of their monthly system and flexible RA obligation. Additionally, on a monthly basis from July through December, the LSEs must demonstrate they have met their revised (due to load migration) local obligation.

In 2017, the RA program successfully provided sufficient resources to meet peak load. The 2017 peak demand (for CPUC jurisdictional LSEs) was forecasted to occur in August 2017 at 41,290 MW.[2] The forward procurement obligation/RA obligation to meet peak demand in August totaled 47,484 MW[3] and LSEs collectively procured 47,756 MW[4] to meet expected system needs (which includes 15% reserve margin). Actual peak load for 2017 (for CPUC and non-CPUC jurisdictional LSEs) occurred on September 1, 2017 at 49,900 MW.[5] The actual peak for CAISO jurisdictional is higher than the CPUC jurisdictional load because it includes CPUC non-jurisdictional load.

CPUC jurisdictional LSEs fulfilled their local RA obligations during the 2017 compliance year. 2017 local RA procurement obligations for CPUC-jurisdictional LSEs totaled 20,964 MW. These obligations were met with a monthly minimum of 21,334 MW. The local obligations were met with

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

[2] See Figure 3.

[3] Ibid.

[4] Ibid.

[5] The data is from CAISO's EMS data. CAISO reported system peak at 49,900 MW. See http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

physical resources, cost allocation mechanism (CAM) resources, reliability must-run (RMR) resources and demand response (DR) resources.[6]

A key to establishing accurate RA procurement targets is the review of LSE demand forecasts. The California Energy Commission (CEC) assesses the reasonableness of LSE demand forecasts and makes monthly plausibility adjustments.[7] In 2016, the CEC made negative plausibility adjustments for ten months of the year. The monthly plausibility adjustments as a percentage of the month's aggregated year-ahead forecast ranged from -1.04% to 0.27%.[8]

Bilateral contracting makes up the majority of forward capacity procurement. However, CAM, RMR, and DR procurement also contribute to meeting RA obligations. These types of procurement are allocated by TAC area with costs passed through to customers. In 2017, CAM, RMR and DR procurement comprised 17% of the overall August RA requirement. In general, CAM procurement has continued to increase since 2011 while RMR procurement decreased to one resource in 2011 but is going up starting 2018. DR procurement has declined since 2013.[9]

In early 2018, Energy Division staff issued a data request to all CPUC jurisdictional LSEs requesting monthly capacity prices paid by (or to) LSEs for every RA capacity contract covering the 2017 – 2021 compliance years. A total of 5,347 monthly contract prices were collected from the data request and used in the price analysis contained in this report. The contract values are weighted by the number of MW in the contract and compared across zone, local area, month, and year. The weighted average price for all capacity in the dataset is $2.71 kW-month.[10] The weighted average capacity price for capacity South of Path 26 is about 50.5% higher than the weighted average capacity price of North of Path 26 capacity. As expected, capacity prices are highest during the months of July through September[11] and in the following locally constrained areas: San Diego, LA Basin, and Big Creek-Ventura.[12] The price of capacity varies significantly between month, local area, and zone.

While many new resources were added during 2017, the overall capacity that can be used to meet LSEs' RA requirements decreased considerably. This was in large part due to the adoption of ELCC for 2018, which changed how solar capacity was calculated and reduced August solar capacity by approximately 50%. Additionally, 3,851 MW of older gas and cogeneration facilities retired during 2017. While this was partially offset by 438 MW of new resources, overall 2017-2018 saw a significant decrease in available capacity.

Because the RA program requires LSEs to acquire capacity to meet load and reserve requirements, when LSEs do not fully comply with RA program rules,[13] the Commission issues citations or starts enforcement actions. In total, the Commission issued six citations for violations related to

[6] See Table 5.

[7] To correct LSE estimations of customer retention, the CEC prepares a plausibility adjustment that estimates customer retention by certain LSEs.

[8] See Table 2.

[9] See Table 13.

[10] See Table 7.

[11] See Table 9.

[12] See Table 8.

[13] 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).

compliance year 2017 for a total of $150,110 and collected $150,110 in payments from LSEs from these citations.

2 Changes to the RA Program for 2017

Decisions (D.)16-06-045 adopted several new rules for the 2017 compliance year, including the following:

A) The Commissions Resource Adequacy program is modified as follows:

a. Energy Division's revised proposal to use contract capacity for third party Demand Response resources that directly bid in the market of the California Independent System Operator for Resource Adequacy compliance years 2017, 2018, and 2019 is adopted. These resources are exempt from the use of Load Impact Protocols to establish capacity for this period; contract capacity will be used instead.

b. All biomass, biogas, and cogeneration facilities, regardless of qualifying facility status, that are able to submit a schedule into the day-ahead market, but are not dispatchable may receive a qualifying capacity value based on the higher of their bid or self-scheduled amounts in the day-ahead market.

B) Following an appropriate California Independent System Operator stakeholder process, Energy Division shall convene a working group to be comprised of, at a minimum, the California Independent System Operator, the three Investor Owned Utilities, Demand Response providers and other parties with technical expertise, to develop clear recommendations to the Commission on the following:

a. Necessary program tariff and contract modifications and/or new provisions to enable pre-dispatch of Local Resource Adequacy resources,

b. Contract provisions related to the minimum required number of pre-dispatches per year, based on the California Independent System Operator estimates of total pre-dispatch need in each local area,

c. Any other modifications to policy or rules necessary to ensure that Demand Response resources can qualify as local Resource Adequacy, based on a non-discriminatory application of those rules.

C) Energy Division is authorized to:

a. Re-issue its May 12, 2016 load forecasting document as a proposal for Resource Adequacy compliance year 2018 by September 1, 2016, including any changes, consistent with our goals.

b. Hold at least one full-day, in person workshop to discuss this proposal by November 1, 2016. Provide an opportunity during the workshop for any party who wishes to present proposed changes to the staff proposal to do so. Energy Division and/or the assigned Administrative Law Judge (ALJ) may set a deadline for parties to make proposed changes in advance. Energy Division may revise its proposal following the workshop, according to a schedule developed by the ALJ.

D) Energy Division is authorized to attempt to obtain appropriate bid and self-schedule data and to implement the Qualifying Capacity calculation for pre-dispatch resources. In the event that not all bid data is available or the calculation is otherwise infeasible, Energy

Division may adapt this calculation as needed, including by using settlement data as a supplement.

3 Load Forecast and Resource Adequacy Program Requirements

The RA program requires its jurisdictional LSEs to ensure system reliability by demonstrating through monthly and annual compliance filings that they have sufficient capacity commitments to satisfy all system, local, and flexible requirements.

Monthly and annual system RA requirements are based on load forecast data filed annually by each LSE and adjusted by the CEC. The adopted forecast methodology is known as the "best estimate approach" and requires jurisdictional and non-jurisdictional LSEs to submit, on an annual basis, historical hourly peak load data for the preceding year and monthly energy and peak demand forecasts for the coming compliance year that are based on reasonable assumptions for load growth and customer retention. Then, the CEC adjusts the LSE submitted load forecasts, which form the final load forecast used for year-ahead RA compliance. LSEs are also required to submit monthly load forecasts to the CEC that account for load migration throughout the compliance year.

To establish the year-ahead load forecast, the CEC first calculates each LSE's specific monthly coincidence factors[14] 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, short-term, weather normalized peak-load forecast, for each IOU service area. This reconciliation evaluates the reasonableness of the LSEs' forecasts. As part of the reconciliation, the CEC may adjust individual IOU service area forecasts, if the aggregate LSE forecasts differ significantly from CEC's forecasts for reasons other than load migration. The CEC also compares individual LSE forecasts to current peak demand estimates (i.e., August month ahead forecast) and adjusts them if the difference is greater than a tolerance threshold.

Additionally, as specified in D.05-10-042, adjustments are made by the CEC to account for the impact of energy efficiency (EE), distributed generation (DG), and coincidence with the CAISO system peak. Finally, the CEC reconciles the aggregate of the adjusted load forecasts against its own forecast for each IOU service territory. The sum of the adjusted forecasts must be within 1% of the CEC forecast. In the event that the aggregated LSE forecasts diverge more than 1% from the CEC's monthly weather normalized forecasts, a pro rata adjustment is made to reduce the divergence to below 1%.

The CEC uses the aggregated LSE forecasts to create monthly load shares for each TAC area, which are then used to allocate DR, CAM, and RMR RA credits. Flexible RA targets for 2016 were allocated to LSEs using 12 monthly load ratio shares. Local obligations were calculated using the load shares for August of the coming compliance year. The forecasts and the allocations together determine both the annual and monthly system RA obligations.

[14] Adopted in D.12-06-025.

3.1 Yearly and Monthly Load Forecast Process

Since 2012, LSEs have been able to revise their April annual load forecast for load migration. The 2017 revised annual forecasts were due on August 19, 2016. These revised forecast values updated and informed the final year-ahead allocations, which were used in the year-ahead filing process.

The following timeline was used for the 2017 process:

LSEs file historical load information	**March 18, 2016**
LSEs file 2017 year-ahead load forecast	**April 22, 2016**
LSEs receive 2017 year-ahead RA obligations	**July 29, 2016**
Final date to file revised forecasts for 2017	**August 19, 2016**
LSEs receive revised 2017 RA obligations	**September 20, 2016**

For 2017, CPUC staff sent initial allocations to LSEs on July 29, and final allocations to LSEs on September 20, 2016. The allocations included a spreadsheet containing Local RA obligations, load forecasts, and DR, RMR, and CAM RA credits. The spreadsheets were emailed to each LSE via a secure file transfer server.

During the compliance year, LSEs adjusted their load forecasts on a monthly basis to account for load migration. This process is outlined in D.05-10-042. As discussed in the RA Guide for the 2017 compliance year, LSEs must submit a revised forecast two months prior to each compliance filing month.[15] These load forecast adjustments are solely to account for load migration between LSEs, not to account for changing demographic or electrical conditions. D.10-06-036[16] updated this process to allow any load forecast changes or adjustments to be submitted up to 25 days before the due date of the month-ahead compliance filings.

LSEs submit these monthly forecasts to the CEC for evaluation; the CEC reviews the revised forecasts and customer load migrating assumptions. The revised monthly load forecasts update the year-ahead forecast and inform the monthly RA obligations. These monthly forecasts are also used to recalculate load shares which are then used to reallocate CAM and RMR credits which count towards monthly RA compliance. The CPUC and CEC do not rely exclusively on year-ahead load forecasts, which are based on forecast assumptions made more than six months prior to the compliance year, because load migration can have a very large effect on LSE forecasts, particularly for small ESPs. The revised load forecasts also inform the local true-up process discussed in Section 3.3.

[15] Annual RA Filing Guides are available on the CPUC website: http://www.cpuc.ca.gov/General.aspx?id=6311
[16] http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/119856.htm, Ordering Paragraph 6.

3.1.1 Yearly Load Forecast Results

Table 1 shows the aggregate LSE submissions for 2017 and the adjustments that were made by the CEC across the three IOU service areas.[17] These adjustments include plausibility adjustments, demand side management adjustments, and a prorated adjustment to each LSE's forecast to ensure that the total for all forecasts is within 1% of the CEC's overall service area forecast. The forecast also includes a coincident adjustment that calculates each LSE's expected contribution towards coincident service area peak. The forecast for CPUC-jurisdictional LSEs showed an expected peak in August 2017 of 40,944, which represents a 7% decrease from the peak forecast of 43,798 MW in 2016.[18]

Table 1. 2017 Aggregated Load Forecast Data (MW) - Results of Energy Commission Review and Adjustment to the 2017 Year-Ahead Load Forecast

Element	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Submitted LSE Forecast (Metered Load + T&D Losses + UFE)	29,368	28,665	28,043	29,807	32,245	36,463	41,250	43,384	39,828	33,861	29,123	29,902
Adjustment for Plausibility and Migrating Load by CEC	152	(98)	191	(869)	(401)	(820)	(888)	(1,462)	170	(431)	511	603
EE/DG Adjustment	(320)	(310)	(328)	(393)	(419)	(464)	(471)	(485)	(478)	(453)	(318)	(312)
Pro Rata Adjustment to CEC Forecast	(174)	32	(97)	109	125	864	682	1,244	183	497	(104)	(75)
Non-Coincident Peak Demand	**29,026**	**28,289**	**27,809**	**28,654**	**31,551**	**36,043**	**40,573**	**42,682**	**39,704**	**33,475**	**29,212**	**30,116**
Coincidence Adjustment	(817)	(1,003)	(1,572)	(1,753)	(1,236)	(1,794)	(2,280)	(1,738)	(2,093)	(1,169)	(910)	(870)
Final Load Forecast Used for Compliance	**28,209**	**27,285**	**26,237**	**26,901**	**30,315**	**34,249**	**38,293**	**40,944**	**37,611**	**32,306**	**28,302**	**29,246**

Source: CEC Staff.

[17] Because the historical and forecast data submitted by participating LSEs contain market-sensitive information, results are presented and discussed in aggregate.
[18] The 2016 RA report can be found at: http://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442453942.

3.1.2 Year-Ahead Plausibility Adjustments and Monthly Load Migration

Plausibility adjustments most commonly indicate mismatches between the LSE's and the CEC's forecasts of each LSE's customer retention. Table 2 below contains the monthly plausibility adjustments for the 2012 through 2017 compliance years and calculates the monthly plausibility adjustments as a percentage of the monthly year-ahead forecast for 2017.

In 2017, the CEC's plausibility adjustments reduced total load on seven months and increased load on five months. In 2017, the CEC found that all nine CCAs, 13 of 14 ESPs and all IOUs required plausibility adjustments in at least one month, an increase over 2016 when 11 of 21 ESPs and CCAs and all three IOUs required an adjustment. The 2017 monthly plausibility adjustments as a percentage of that month's aggregated year-ahead forecast ranged from 0.07% to -1.04%. Adjustments to IOU forecasts typically reflect differences in fundamental forecast assumptions compared to the CEC forecast, such as expected economic growth or the temperature response of load as well as load migration to CCAs not captured in the year-ahead load forecast. Four CCAs did not participate in the year-ahead load forecast so that load was assigned to the IOUs in the year-ahead timeframe.

Table 2. CEC Plausibility Adjustments, 2012-2017 (MW)

Compliance Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2012	88	72	55	67	67	(545)	(60)	(947)	(218)	576	95	68
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
2017 Plausibility Adjustment /Load	-0.16%	-0.20%	-0.36%	-0.48%	-0.75%	-1.04%	-0.07%	-0.92%	0.22%	-0.60%	-1.04%	0.27%

Source: Aggregated year-ahead CEC load forecasts, 2012-2017.

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 2017. There were generally only small net load migration adjustments from the annual 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 2.81% for April 2017. On a megawatt basis, the net monthly load migration adjustments ranged from -148 to 779 MW in 2017.

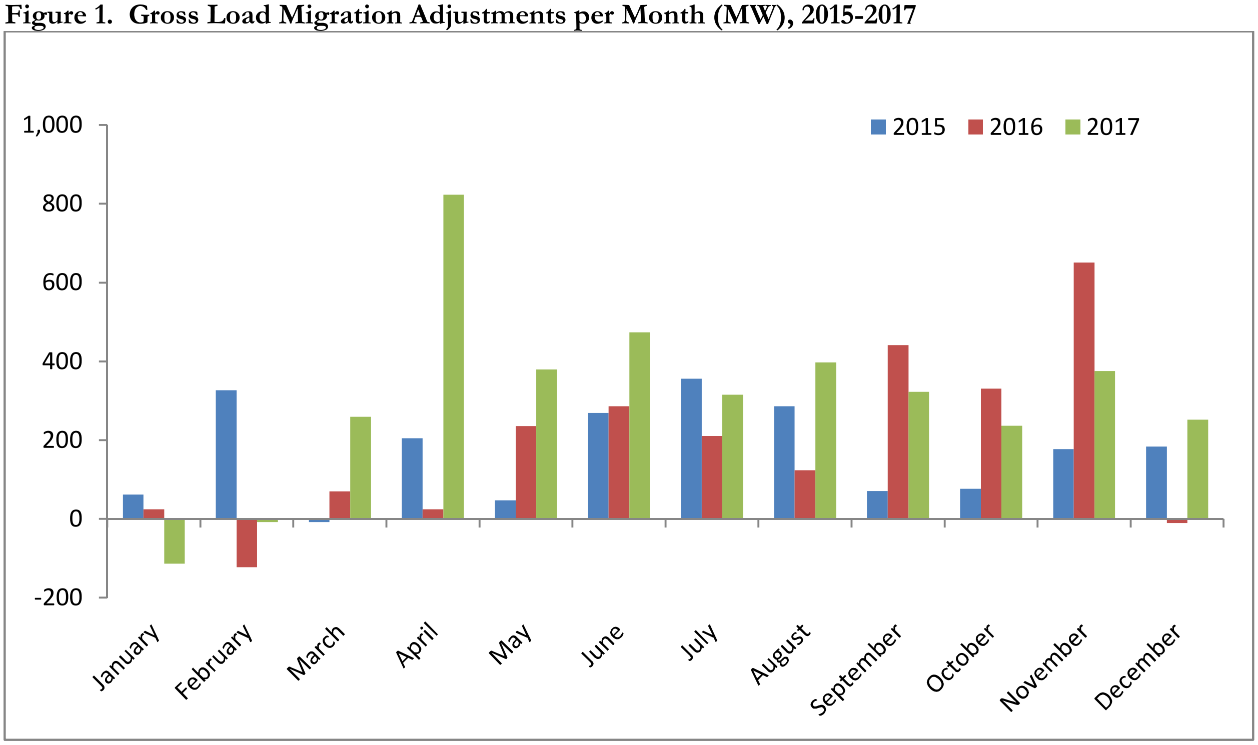
Table 3. Summary of Load Migration Adjustments in 2017 (MW)

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Forecasts, July 2016	28,209	27,285	26,237	26,901	30,315	34,249	38,293	40,944	37,611	32,306	28,302	29,246
Monthly Adjustments, 2017	-148	-44	217	779	335	425	266	346	268	187	335	215
Final Forecasts in Monthly RA Filings	28,061	27,241	26,454	27,680	30,649	34,673	38,560	41,290	37,880	32,493	28,637	29,462
Monthly Adjustments/ Final YA Load Forecast	-0.53%	-0.16%	0.82%	2.81%	1.09%	1.22%	0.69%	0.84%	0.71%	0.58%	1.17%	0.73%

Source: Aggregated load forecast adjustments submitted to the CEC and CPUC through 2017.

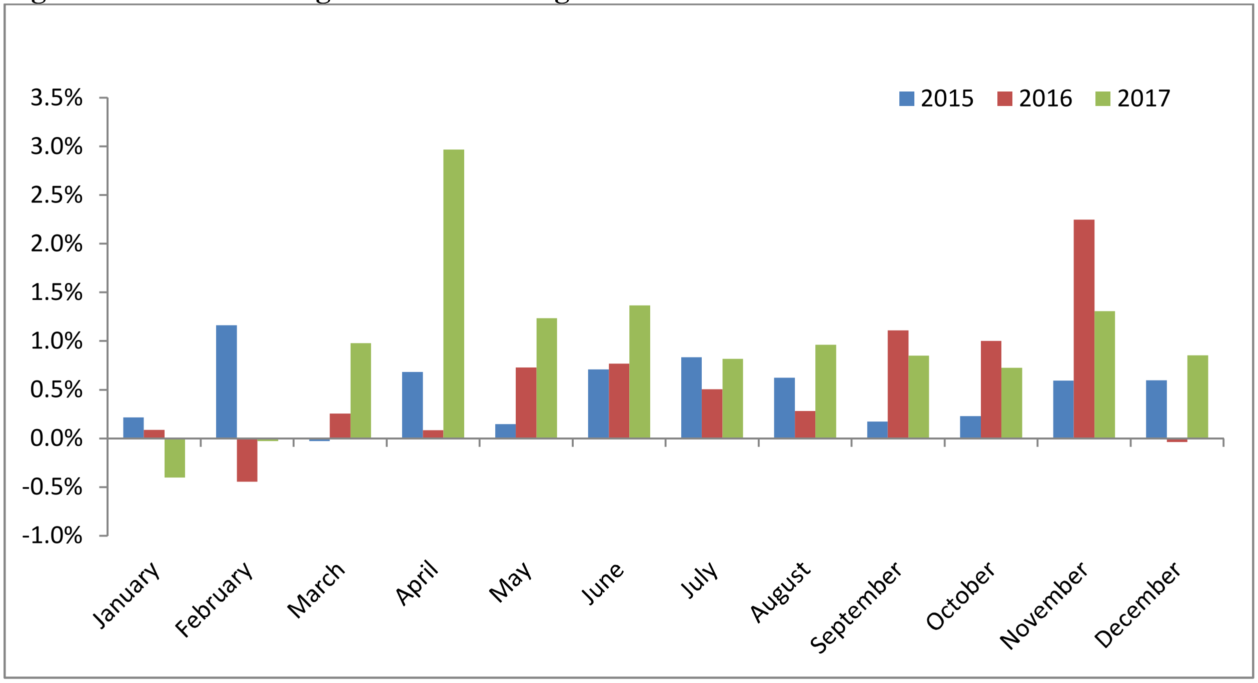
Figure 1 and Figure 2 illustrate the gross monthly load migration between LSEs from 2015 through 2017. Load migration remained relatively low throughout this period with monthly migration remaining below 850 MW and 3% of total load.

Figure 1. Gross Load Migration Adjustments per Month (MW), 2015-2017



Source: Monthly forecast adjustments submitted by LSEs, 2015-2017.

Figure 2. Gross Load Migration as Percentage of Total Load



Source: Monthly forecast adjustments submitted by LSEs, 2015-2017.

3.2 System RA Requirements for CPUC-Jurisdictional LSEs

CPUC-jurisdictional LSEs met their individual and collective system RA requirements for every month of 2017. The total MW of RA resources procured exceeded the total system Resource Adequacy Requirement (RAR) by 0.5% to 3.5%, depending on the month. Table 4 shows the total CPUC-jurisdictional RA procurement for each month of 2017, broken down by: physical resources within the CAISO's control area, DR, RMR, and imports. Note that CAM resources are taken off of non-IOU LSE's RA requirement and IOUs receive an increase in RA requirement and show the CAM resources in their RA showing, essentially netting zero for procured resources. Physical resources include CAM resources. To show the amount of CAM resources, they are reported separately. RA obligations are reported here as the aggregate monthly load forecast plus the 15% Planning Reserve Margin (PRM). DR resources, including DRAM resources, are also reported with the 15% PRM applied.

The data represented in Table 4 reflect the committed RA procurement for 2017 for all CPUC jurisdictional LSEs by contract type, and compares this procurement to the procurement obligation. In 2017, 85 to 89% of all committed RA capacity, including CAM, was procured from unit-specific physical resources within the CAISO control area, 6 to 10 percent of capacity was from imports, and 3 to 5 percent was from DR resources. CAM and RMR resources consisted of 13 to 20 percent of total RA capacity procured.

Table 4. 2017 RA Filing Summary – CPUC-Jurisdictional Entities (MW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
RAR without DR,CAM, & RMR	32,270	31,327	30,422	31,832	35,247	39,875	44,343	47,484	43,561	37,367	32,932	33,881
Phys. Res.	29,121	28,248	28,162	29,191	31,063	35,519	38,615	41,533	37,279	32,502	28,859	30,368
Imports	2,594	2,377	1,885	1,972	2,405	2,421	3,886	3,889	4,463	3,137	3,101	2,456
DR plus 15% PRM	1,171	1,241	1,279	1,456	1,826	1,987	2,101	2,184	2,026	1,932	1,400	1,169
CAM & RMR	6,191	6,222	6,157	6,198	6,148	6,509	6,503	6,240	6,258	6,393	6,470	6,518
Total	33,035	32,015	31,474	32,769	35,444	40,076	44,752	47,756	43,917	37,721	33,510	34,141
Total/RAR	**102.4%**	**102.2%**	**103.5%**	**102.9%**	**100.6%**	**100.5%**	**100.9%**	**100.6%**	**100.8%**	**100.9%**	**101.8%**	**100.8%**

Source: Aggregated LSE Monthly RA Filings.

In 2017, total committed RA resources, including DR and CAM, ranged from 31,474 MW in March to 47,756 MW in August. These resources enabled CPUC jurisdictional LSEs to meet between 100.5 and 103.5 percent of total procurement obligations in each summer month. Actual peak demand in CAISO jurisdiction, which includes CPUC-jurisdictional and non-CPUC jurisdictional of 49,900 MW occurred on September 1, 2017.

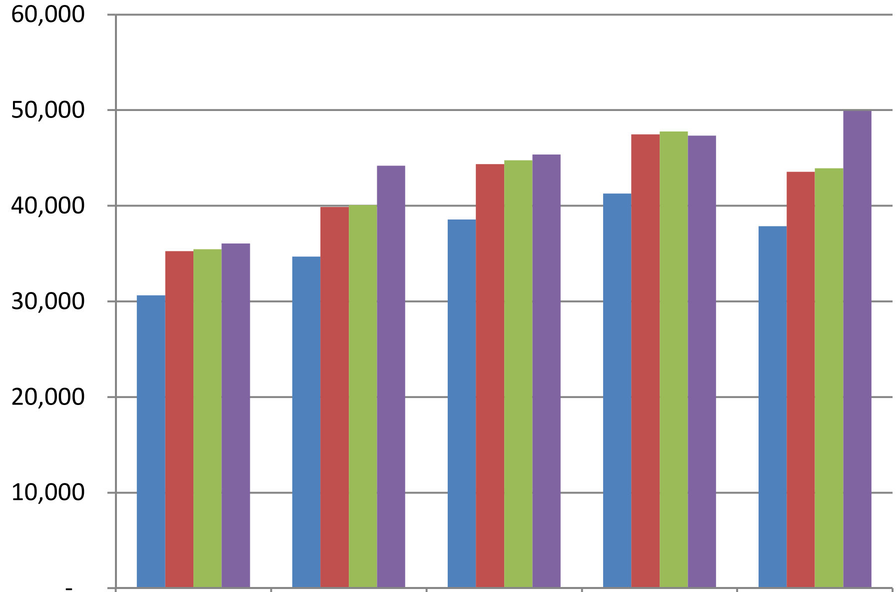
Figure 3 shows 2017 total load forecast, procurement obligation (forecast plus planning reserve margin), and total committed RA for only CPUC-jurisdictional LSEs. These three data points are compared with the CAISO-jurisdictional actual peak load forecasts. The difference between the red and the green bars reflect the excess amount of committed resources to meet the monthly RA requirement. Again, the CAISO jurisdictional peak is higher than the CPUC RA obligations and Total RA committed because it includes non-CPUC jurisdictional load.

The CPUC RA program is coordinated with the CAISO's reliability requirements. In addition to receiving RA plans from CPUC-jurisdictional LSEs, the CAISO also receives resource adequacy filings from non-CPUC-jurisdictional LSEs. In past years, we have included non-CPUC-jurisdictional LSEs information in this graph. However, because CAISO would not provide this data, we are again unable to provide this information for 2017.

To provide an indication of the how the chart would change if we had been able to include the aggregate non-CPUC-jurisdictional LSEs information, the load ratios for non-jurisdictional LSEs was 9.34% in August 2017.[19]

[19] These values are derived from the CEC year-ahead aggregate load forecasts used for allocating local capacity requirements to LSEs.

Figure 3. 2017 CPUC Load Forecast, RA Requirements, Total RA Committed Resources, and Actual Peak Load (For Summer Months)



	May	Jun	Jul	Aug	Sep
Load Forecast (CPUC-Jurisd.)	30,650	34,674	38,559	41,290	37,879
Forward Commitment Obligation	35,247	39,875	44,343	47,484	43,561
Total RA Resources Committed	35,444	40,076	44,752	47,756	43,917
Actual Peak Load (CAISO)	36,040	44,183	45,366	47,345	49,900

Source: Aggregated data compiled from monthly CPUC RA Filings, CEC load forecasts, and CAISO EMS data.

3.3 Local RA Program – CPUC-Jurisdictional LSEs

Beginning with the 2007 compliance year, the CPUC required LSEs to file an annual local RA filing, showing that they have met 100% 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 minimum local resource capacity required in each local area to meet energy needs using a 1-in-10 weather year and N-1-1 contingencies.[20] The results of the analysis are adopted in the annual CPUC RA decision and allocated to each LSE based on their August load ratio in each Transmission Access Charge (TAC) area.

All LSEs are required to show sufficient resources to meet each of the 12 months of their local requirement on or around October 31. This is the same due date as the LSEs' system year-ahead showing.[21] In D.16-06-045, the CPUC adopted the 2017 local RA obligations for the ten locally constrained areas (Big Creek/Ventura, LA Basin, San Diego, Greater Bay Area, Humboldt, North Coast/North Bay, Sierra, Stockton, Fresno, and Kern). As in previous years, the following local areas are aggregated to the category "other PG&E areas": Humboldt, North Coast/North Bay, Sierra, Stockton, Fresno, and Kern.

3.3.1 Year-Ahead Local RA Procurement

CPUC-jurisdictional LSEs' overall local RA procurements for 2017 are summarized in Table 5. CPUC-jurisdictional LSE procurement exceeded local RA obligations in each of the five local areas by 0.25 to 5.57%. Aggregate minimum procurement across all local areas exceeded local RA requirements by 1.77% in 2017. Local requirements are allocated to LSEs net of RMR, as these resources reduce the LSE's local RA obligation. CAM resources are counted as an increase for IOUs' RA requirement and a decrease in non-IOU LSE's RA requirement so they net to zero. Starting in 2013, RA values of event-based DR resources are reported through the RA filings, similar to a physical resource. Historically, the local RA values associated with the DR resources were netted off the local RA requirements allocated to LSEs.

Table 5. Local RA Procurement in 2017, CPUC-Jurisdictional LSEs

Local Areas in 2017	Total LCR	CPUC-Jurisdictional Local RAR	Minimum Physical Resources per Month	Local RMR & CAM Credit	Local DR	Minimum Procurement/ Local RAR
LA Basin	7,368	6,589	6,616	2,247	939	100.40%
Big Creek/Ventura	2,057	1,534	1,548	737	163	100.92%
San Diego-IV	3,570	3,570	3,579	398	37	100.25%
Greater Bay Area	5,617	4,540	4,597	1,277	58	101.27%
Other PG&E Areas	5,937	4,731	4,995	295	167	105.57%
Totals	24,549	20,964	21,334	4,954	1,365	101.77%

Source: 2017 RA filings

[20] Local Capacity Requirement (LCR) studies and materials for 2017 and previous years are posted at http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx .

[21] More detail regarding the overall local RA program can be found in Section 3.3 of the 2007 Resource Adequacy Report.

3.3.2 Local and Flexible RA True-Ups

As part of the partial reopening of direct access in 2010, the Commission adopted a true-up mechanism to adjust each LSE's local RA obligation to account for load migration in D.10-03-022. The true-up process was modified in D.10-12-038 for the 2011 compliance year and beyond. The modified local true-up process consisted of two reallocations cycles.

In D.14-06-050, the true-up process was changed to one reallocation per year. This process requires LSEs to file revised load forecasts for August's peak load once during the compliance year. The CEC uses these revised August load forecasts to update each LSE's load share, which is then used to revise each LSE's local capacity requirements. The difference between the original allocations and the new requirements is allocated to LSEs as an incremental local RA requirement, which the LSEs must meet in their monthly filings.

Starting in 2015, the true-up process also included flexible RA. LSEs filed revised load forecast for July to December, which were used to establish revised load ratios to reallocate flexible requirement for the second half of 2016.

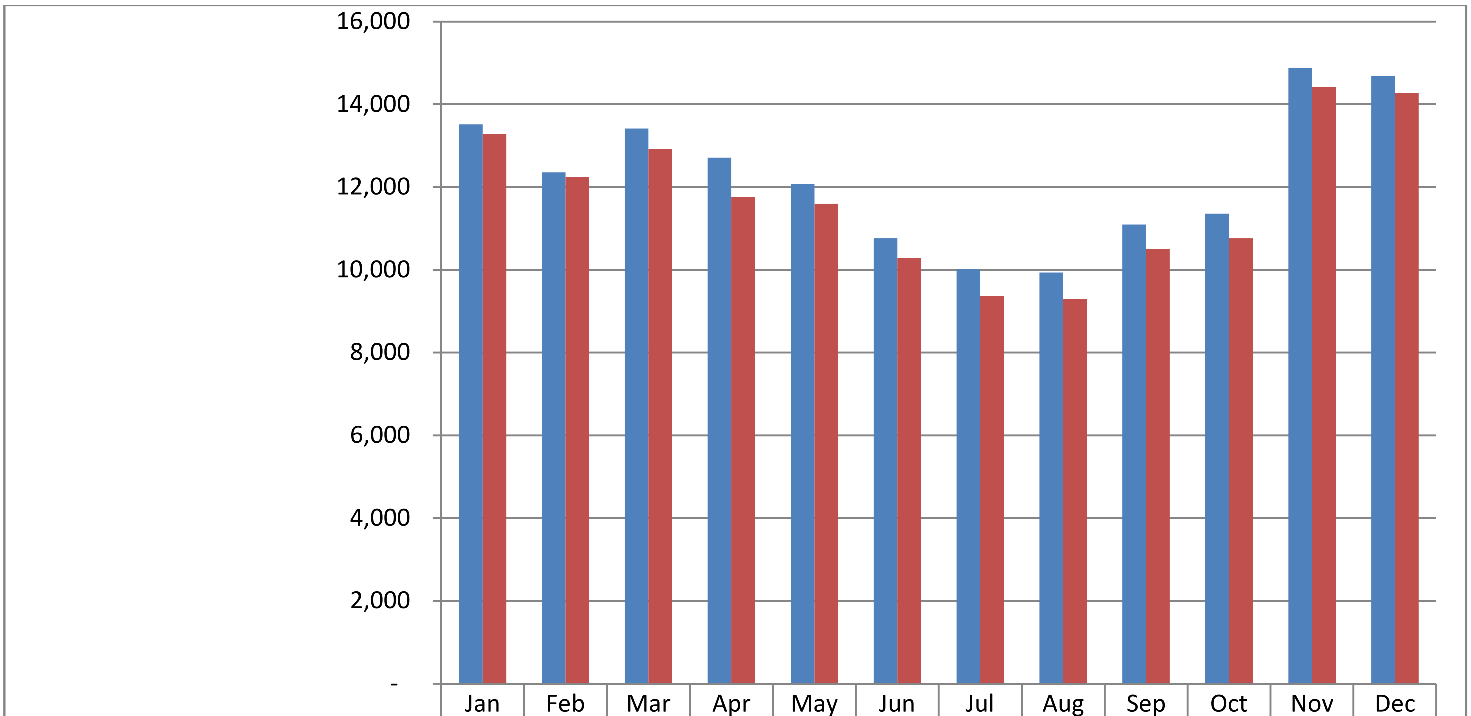
In the allocation cycle for 2016, LSEs submitted revised August forecasts to the CEC on March 16, 2016 along with their June to December load forecasts. After reviewing these values, the CEC revised the August load shares. Energy Division used the revised load shares to recalculate individual LSE local requirements, which were then netted from the individual LSE year-ahead local requirements. The netted local requirement values, known as incremental local allocations, along with incremental flexible allocations, were then sent to LSEs on April 6, 2017, in the Quarter 3 CAM-RMR allocation letters. 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 using these values.

3.4 Flexible RA Program – CPUC-Jurisdictional LSEs

Beginning with the 2015 compliance year, CPUC adopted a flexible RA requirement for LSEs where they are required to demonstrate that they have procured 90% of their monthly flexible capacity requirement in the year-ahead process and 100% of the flexible capacity requirement in the month-ahead process.[22] The flexible capacity needs are developed through CAISO's annual Flexible Capacity Study, where the flexible capacity need is 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. Resources are considered as flexible capacity if they can ramp up or sustain output for 3 hours.

Figure 4 shows the flexible capacity requirement and the flexible capacity shown on RA plans by CPUC-jurisdictional LSEs for each month of 2017.

Figure 4. Flexible RA Procurement in 2017, CPUC-Jurisdictional LSEs



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2017 Flexible Capacity on RA Plan	13,516	12,357	13,418	12,710	12,073	10,762	10,011	9,936	11,099	11,359	14,886	14,690
2017 Flexible RA Requirements	13,281	12,238	12,918	11,764	11,600	10290	9,366	9,292	10,501	10,761	14,425	14,276

Source 2017 RA filings

[22] D.13-06-024, D14-06-050

4 Resource Adequacy Procurement, Commitment and Dispatch

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

The CAISO utilizes these committed resources through its day ahead market, real time market, and Residual Unit Commitment (RUC). The CAISO also relies on out-of-market commitments (e.g., Exceptional Dispatch (ExD), Capacity Procurement Mechanism (CPM), and Reliability Must Run (RMR) contracts) to meet reliability needs that are not satisfied by the Day Ahead, Real Time, and RUC market mechanisms.

To ensure funding for new generation needed for grid reliability, the CPUC authorized the IOUs, beginning in the Long Term Procurement Plan (LTPP) proceeding for 2007, to procure new generation resources. These resources were required to meet system and local reliability needs. Resources procured to meet reliability must go through something known as the Cost Allocation Mechanism (CAM), which allows the net costs of new generation resources to be recovered from all benefiting customers in the IOU's TAC area. From 2007 to 2014, the RA benefits of new generation resources are applied as a credit towards RA requirements (the local credit is applied to the overall local RA obligation and the system credit is allocated monthly). Beginning in 2015, the CAM resources are allocated as an increase in IOUs' RA requirement and a decrease in non-IOU LSEs' RA requirement, with the IOUs showing the resources in their RA filing. These CAM resources carry the same must offer obligation as all other RA resources.

4.1 Bilateral Transactions- RA Price Analysis

The bilateral RA transactions, in combination with other market opportunities, provide generation owners and developers the opportunity to obtain revenue to cover their fixed costs. Prices of bilateral contracts could vary substantially depending on unit location, transmission constraints, and market power.

On January 24, 2017, Energy Division issued a data request to all 29 CPUC-jurisdictional LSEs (comprised of three IOUs, 14 ESPs, and 12 CCAs) asking for monthly capacity prices paid by (or to) LSEs for every RA capacity contract covering the 2017-2021 compliance years. The data request was confined to RA-only capacity contracts bought or sold covering the period from January 2017 – December 2021. Since RA prices can vary by month, the data request asked for specific monthly prices from each contract. QF contracts, imports, DR, and new generation contracts were excluded from the data set.

Of the 29 LSEs that were sent the data request, Energy Division received twenty-one responses (from three IOUs, and six ESPs, and twelve CCAs), which consisted of a combined 5,347 monthly contract values. These values collectively form the data set used in this price analysis. Key statistics characterizing the reported capacity contracted in each year are shown in Table 6 below. The majority of the capacity in the data set is contracted for 2017 and 2018. This is as expected, since at the time that the data was collected, the 2017 RA compliance year had ended, and there had only been a year-ahead showing and a few month ahead showings required for the 2018 compliance year.

In an attempt to get a better understanding of the magnitude of the data set, we compared the data set to 2017 RA requirements. Since the results include both capacity MWs bought and sold, the totals may include the double counting of the same MW being used to meet the monthly RA requirement. In 2017, the sum of monthly contracted capacity represents approximately 23% of the 2017 monthly sum of RA requirements net CAM, RMR, and DR allocations.[23] The remainder of RA capacity for that year either 1) was not reported because it was not procured via an RA-only capacity contract, or, 2) was procured by an LSE that did not respond to the Energy Division's data request. While a data set covering 23% of 2017 capacity is far from complete, it nevertheless provides important insights into overall RA pricing in that year. If we use the aggregate 2017 monthly capacity requirements as a proxy to determine how much data in each year is representative of the total monthly RA requirements, it appears that, for 2018, the sum of monthly contracts represent about 37%, for 2019 the data represents about 18%, for 2020 the data represents about 9%, and for 2021 the data represents about 3%.

Table 6. Capacity Prices by Compliance Year, 2017-2021

	2017 Capacity	2018 Capacity	2019 Capacity	2020 Capacity	2021 Capacity
Contracted Capacity (MW)	102,067	115,080	56,249	28,300	9,221
Percentage of total contracted MW in dataset	33%	37%	18%	9%	3%
Weighted Average Price ($/kW-month)	$2.46	$2.58	$3.09	$3.37	$2.80
Average Price ($/kW-month)	$2.02	$2.29	$2.96	$3.06	$3.02
Minimum Price ($/kW-month)	$0.10	$0.75	$1.28	$1.31	$1.45
Maximum Price ($/kW-month)	$6.43	$10.09	$6.15	$6.00	$6.00
85% of MW at or below ($/kW-month)	$4.33	$3.65	$3.65	$3.65	$3.93

Source: 2017-2021 Price Data submitted by the LSEs

Energy Division staff aggregated the contracts across all compliance years, sorted them into the categories shown in Table 7 below, and performed a statistical analysis of each category. Local and

[23] The 20% is calculated by dividing the sum of contracted capacity in 2017 (102,067 MW) by the sum of all 2017 monthly RA obligations net of CAM, RMR, and DR allocations (440,540 MW).

system RA contracts are differentiated by the unit's location, which is taken from the 2018 Net Qualifying Capacity list.[24] Local RA Capacity areas are described in Section 3.3.

Table 7 presents the summary statistics from the data set. All prices are in units of nominal dollars per kW-month. The data set represents 310,917 MW-months of capacity under contract. Of that capacity, 54% is located in the North of Path 26 (NP-26) Zone, and 46% is located in the South of Path 26 (SP-26) Zone.[25] The data set also shows that 75% of the total capacity is located in local areas, with 25% located in the CAISO system area. Of the local RA capacity reported, the majority – 57% – is located in one of the SP-26 local areas; the remaining 43% is located in NP-26 local areas. The CAISO system RA has the opposite breakdown, with 89% of capacity located in the NP-26 Zone and only 11% of System RA capacity located in the SP-26 Zone.[26]

Table 7. Aggregated RA Contract Prices, 2017-2021

	All RA Capacity Contracts			Local RA Capacity Contracts			CAISO System RA Capacity Contracts		
	Total	NP-26	SP-26	**Subtotal**	NP26	SP26	**Subtotal**	NP26	SP26
Contracted Capacity (MW)	**310,917**	167,563	143,354	**234,678**	100,027	134,651	**76,239**	67,537	8,703
Percentage of Total Capacity in Data Set	**100%**	54%	46%	**75%**	43%	57%	**25%**	89%	11%
Number of Monthly Values	**5,347**	3,583	1,764	**3,888**	2,574	1,314	**1,459**	1,009	450
Weighted Average Price ($/kW-month)	**$2.71**	$2.20	$3.31	**$2.92**	$2.24	$3.42	**$2.09**	$2.15	$1.59
Average Price ($/kW-month)	**$2.36**	$2.25	$2.58	**$2.59**	$2.42	$2.91	**$1.76**	$1.83	$1.60
Minimum Price ($/kW-month)	**$0.10**	$0.50	$0.10	**$0.60**	$0.75	$0.60	**$0.10**	$0.50	$0.10
Maximum Price ($/kW-month)	**$10.09**	$10.09	$6.43	**$10.09**	$10.09	$6.43	**$10.09**	$10.09	$5.50

[24] The 2018 Net Qualifying Capacity list can be found at http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx
[25] Path 26 is defined in the WECC Path Rating Catalog, viewable at https://www.wecc.biz/Reliability/NDA/WECC_2016_Path_Rating_Catalog.pdf
[26] The CAISO System RA category is applied to contracts with resources that are not located in Local Capacity Areas. It can be further divided into NP-26 and SP-26 sub-categories, which indicate whether those contracts are north or south of Path 26.

85% of MW at or below ($/kW-month)	**$3.65**	$3.00	$4.19	**$3.65**	$2.75	$4.25	**$3.00**	$3.00	$2.07

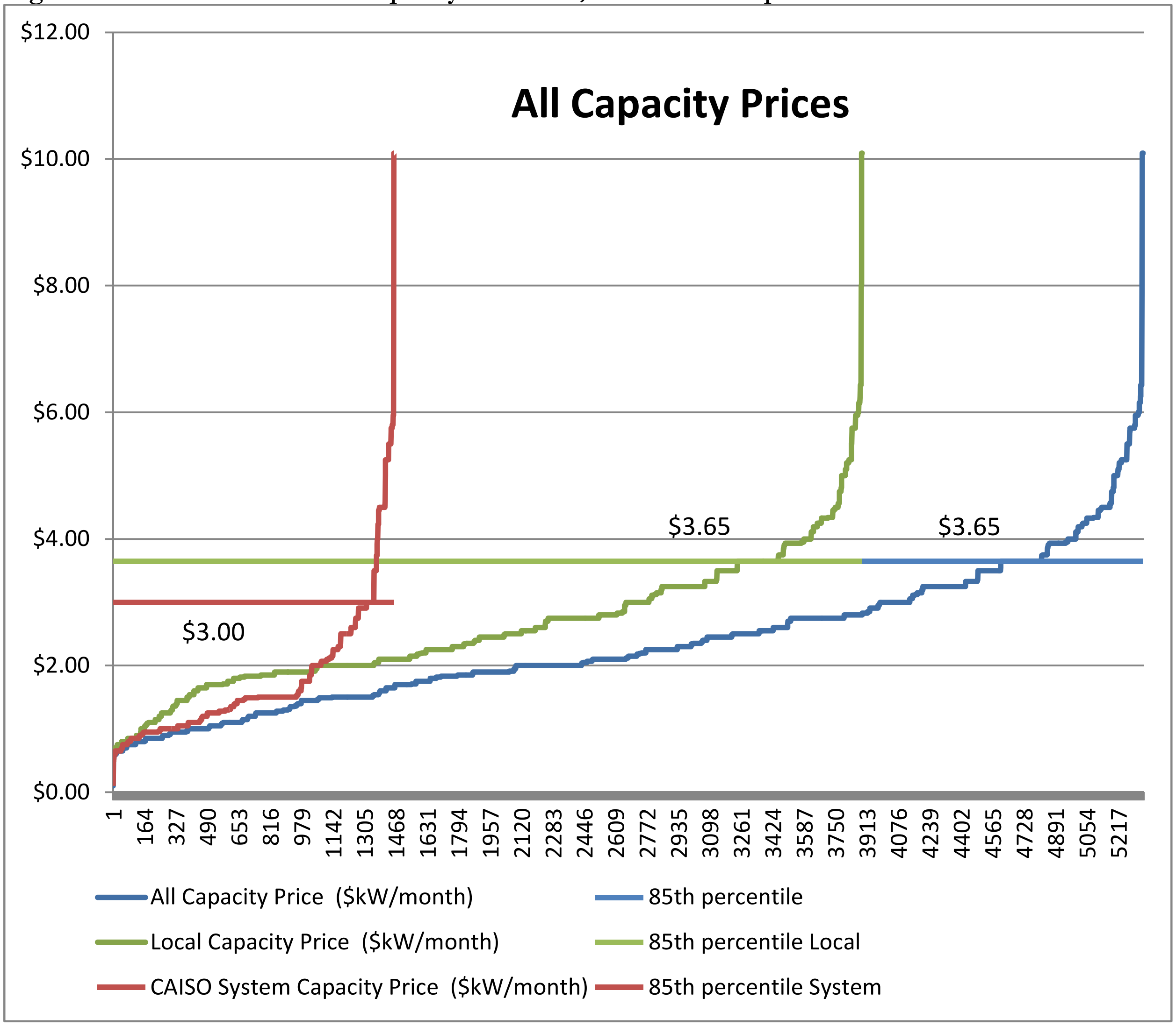
Source: 2017-2021 Price Data submitted by the LSEs

The weighted average price for all capacity is $2.71/kW-month. This is $0.39 lower than the weighted average price reported in the 2016 RA price analysis. The weighted average price for SP-26 capacity (including local and system RA) is $3.31/kW-month, which is about 50% higher than the NP-26 weighted average price of $2.20/kW-month. Higher prices in the SP-26 Zone are also revealed through the 85th-percentile statistics, which indicate the price under which 85 percent of the contracted MW values in a given category fall. In SP-26, 85% of contracted MW prices are at a price of $4.19/kW-month or less, while in NP-26, 85% of the MWs contracted are at a price of $3.00/kW-month or less.

The weighted average price of local RA capacity is 40% higher than the weighted average price of system RA capacity. This is expected, as local RA is a more constrained product. Unlike the 2016 RA report, the weighted average price of local RA capacity in the NP-26 Zone is higher than the weighted average price of system RA capacity in the NP-26 Zone. This suggest that capacity in local areas north of path 26 are more constrained than in past years.

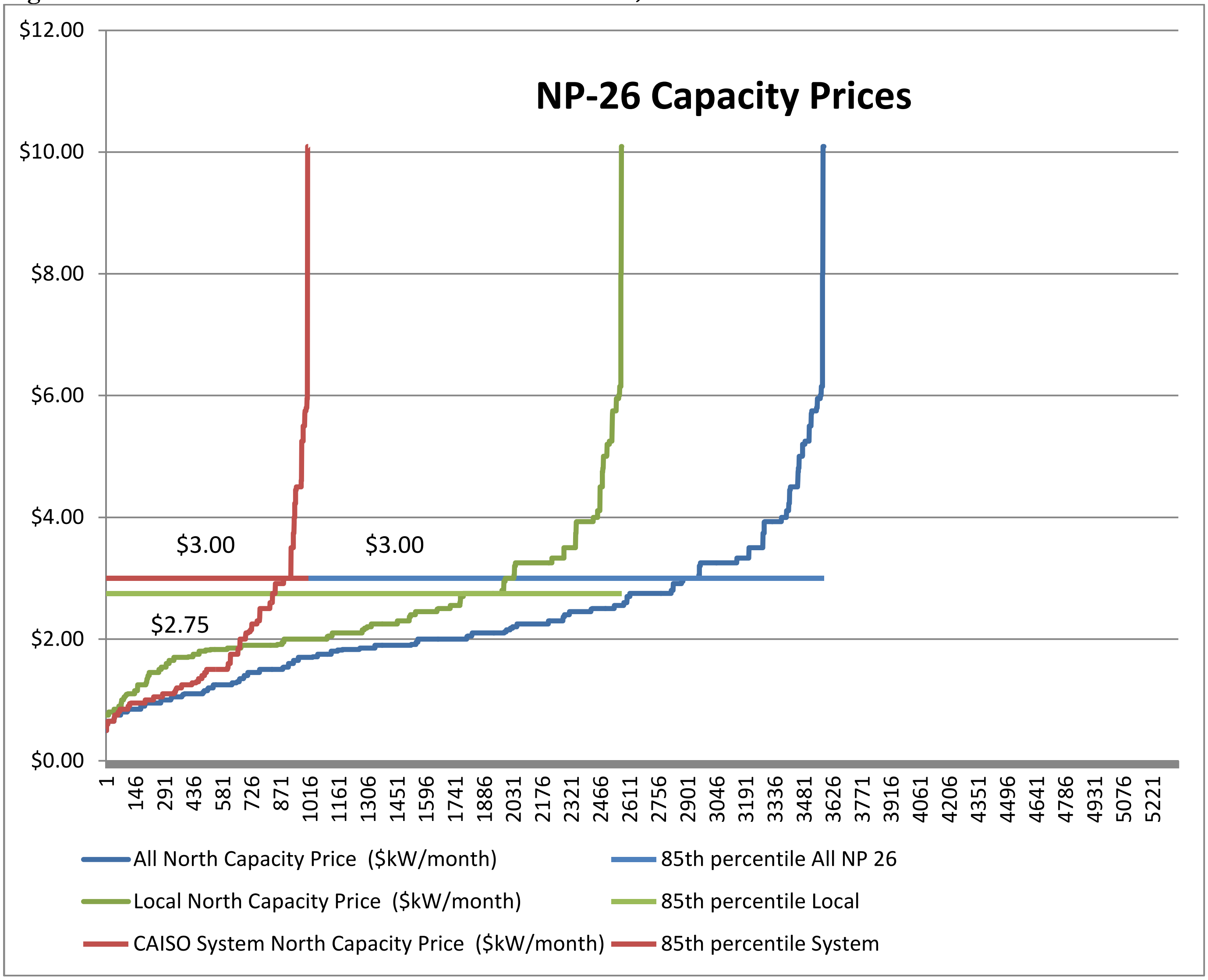
The price curves for RA-only contracts are shown by category in Figure 5 – Figure 7. Figure 5 displays three price curves. The All Capacity price curve includes all contract prices in the data set plotted as a price curve along a cumulative MW x-axis. The other two price curves show either local or system RA capacity contracts only. Because 75% of the capacity in the data set is local RA, the overall price curve more closely matches local RA prices than system RA prices.

Figure 5. Price Curves for RA Capacity Contracts, 2017-2021 Compliance Years



Source: 2017-2021 Price Data submitted by the LSEs

Figure 6. RA Price Curves for Resources North of Path 26, 2017- 2021

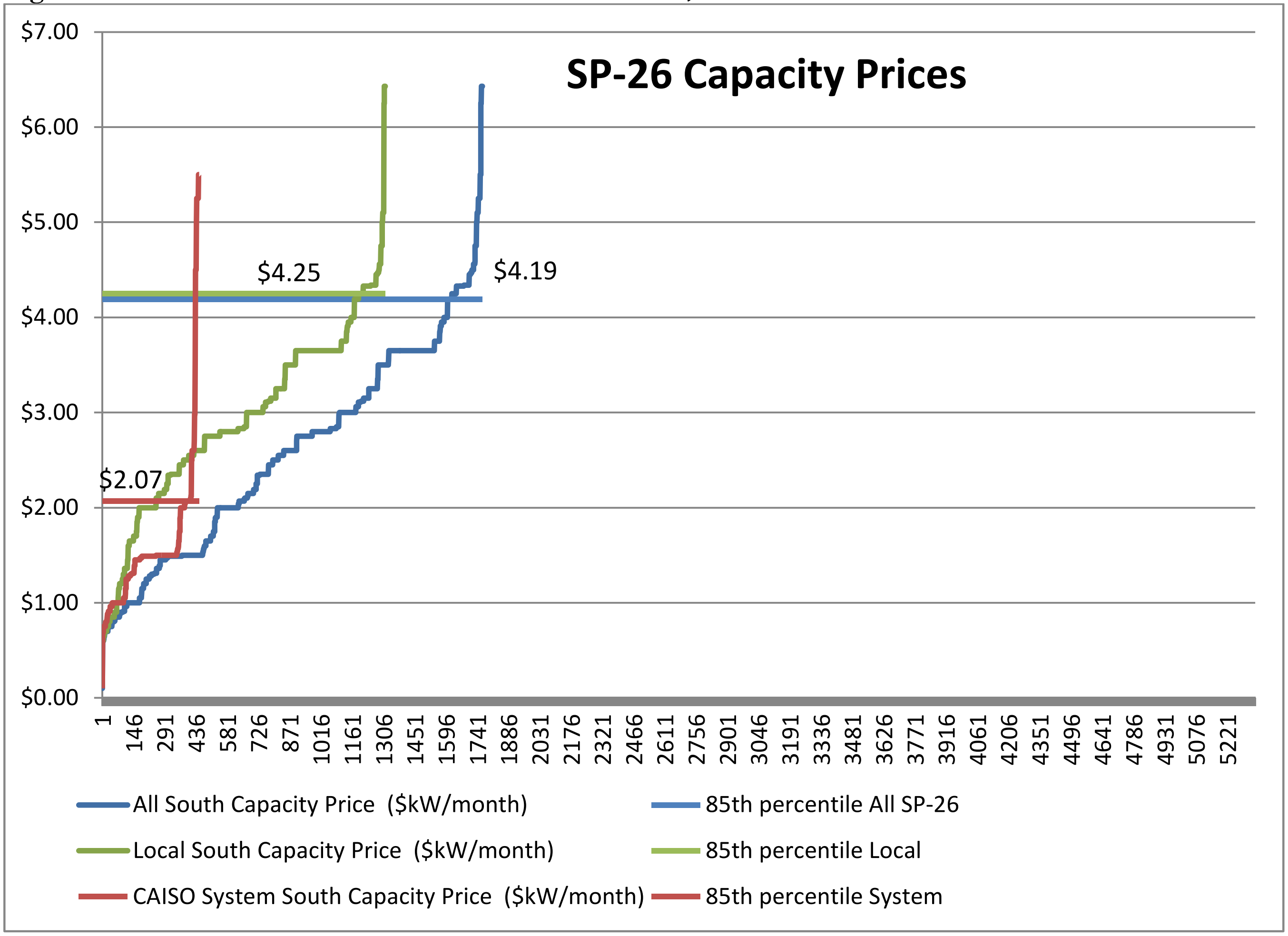


Source: 2017-2021 Price Data submitted by the LSEs

Figure 6 displays price curves for contracted capacity north of Path 26. Like Figure 5, the price curves are differentiated by local and system RA capacity. The weighted 85th-percentile contract price of system RA Capacity is $0.25/kw-month higher than local RA, indicating that there is less premium placed on Local RA capacity north of Path 26. However, the gap has narrowed since the 2016 RA report, where the difference was $0.50/kw-month. The 85th-percentile of NP-26 RA prices are lower than the 85th percentile of all aggregated RA contract prices, which indicates NP-26 prices are still lower than the overall price.

Figure 7 displays price curves of contracted capacity south of Path 26. The vast majority of contracted capacity in the SP-26 Zone is with resources located in local areas. The weighted 85th-percentile price for local RA capacity is $2.18/kW-month more than for System RA. This is slightly lower than the difference of $2.36/kW-month reported in the 2016 RA report.

Figure 7. RA Price Curves for Resources South of Path 26, 2017-2021



Source: 2017-2021 Price Data submitted by the LSEs

Table **8** reports capacity prices by local capacity area. The LA Basin local area has the highest weighted average price. Bay Area and CAISO system has the highest maximum price. San Diego and Big Creek/Ventura local areas have the highest 85th-percentile price. The 85th-percentile price indicates that 85 percent of the contracted MW in the Big Creek/Ventura local area were procured at prices of $4.45/kW-month or below. According to the average weighed price, LA Basin and Big Creek/Ventura are similar. Looking at the weighted average price of local areas in the North, Other PG&E area local capacity price is slightly higher than Bay Area local capacity.

Table 8. Capacity Prices by Local Area, 2017-2021

	LA Basin	Big Creek/Ventura	Bay Area	Other PG&E Area	San Diego-IV	CAISO System
Contracted Capacity (MW)	83,851	26,500	70,150	29,877	24,300	76,239
Percentage of Total Capacity in Data Set	27%	9%	23%	10%	8%	25%
Weighted Average Price ($/kW-month)	$3.48	$3.45	$2.22	$2.27	$3.18	$2.09
Average Price ($/kW-month)	$2.89	$2.96	$2.58	$2.29	$2.92	$1.76
Minimum Price ($/kW-month)	$0.60	$0.60	$0.85	$0.75	$0.62	$0.10
Maximum Price ($/kW-month)	$6.43	$5.00	$10.09	$6.15	$6.25	$10.09
85% of MW at or below ($/kW-month)	$3.65	$4.45	$2.75	$2.80	$4.33	$3.00

Source: 2017-2021 Price Data submitted by the LSEs

The monthly weighted average capacity prices shown in Table 9 below illustrate that capacity prices are slightly higher from July through September. We would expect to see high prices in the summer given the high demand in the summer months. However, the difference from 2017-2021 is much less drastic than in the past.

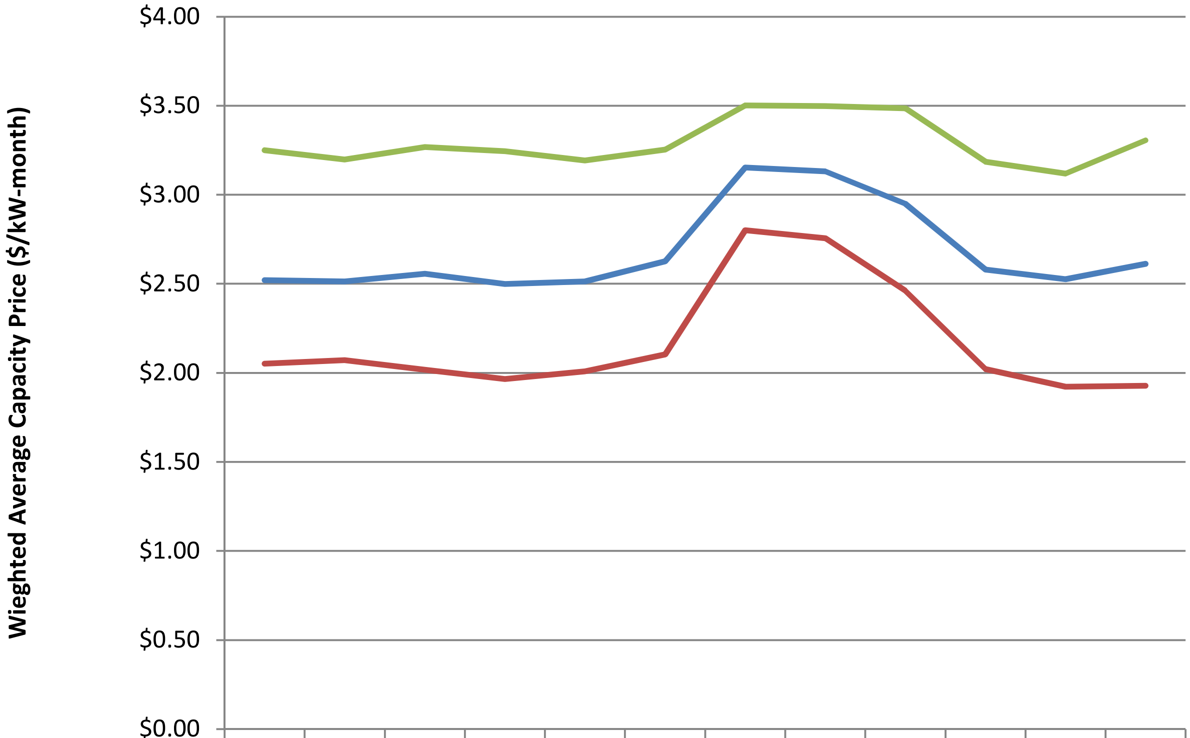
Table 9. RA Capacity Prices by Month, 2017-2021

	Contracted Capacity (MW)	Percentage of Total Capacity in Data Set	Weighted Average Price ($/kW-month)	Minimum Price ($/kW-month)	Maximum Price ($/kW-month)	85% of MW at or below ($/kW-month)
January	22,621	7%	$2.52	$0.60	$6.43	$3.65
February	22,653	7%	$2.51	$0.75	$6.43	$3.65
March	20,335	7%	$2.56	$0.60	$6.43	$3.65
April	21,178	7%	$2.50	$0.50	$6.43	$3.65
May	22,463	7%	$2.51	$0.60	$6.43	$3.65
June	28,853	9%	$2.63	$0.69	$5.80	$3.65
July	31,131	10%	$3.15	$0.75	$10.09	$4.47
August	31,624	10%	$3.13	$0.75	$10.09	$4.45
September	32,148	10%	$2.95	$0.80	$10.09	$4.25
October	27,845	9%	$2.58	$0.58	$5.10	$3.65
November	25,700	8%	$2.53	$0.10	$4.45	$3.65
December	24,368	8%	$2.61	$0.60	$4.45	$3.65

Source: 2017-2021 Price Data submitted by the LSEs

Figure 8 graphs the weighted average capacity prices by month and zone. Overall prices and NP-26 prices are higher in the summer months and more pronounced than SP-26 summer prices. The higher prices in the south for all twelve months may reflect lower supply levels and more constrained local capacity areas in Southern California. However, this effect is not nearly as pronounced as in the past.

Figure 8. Weighted Average RA Capacity Prices by Month and Zone

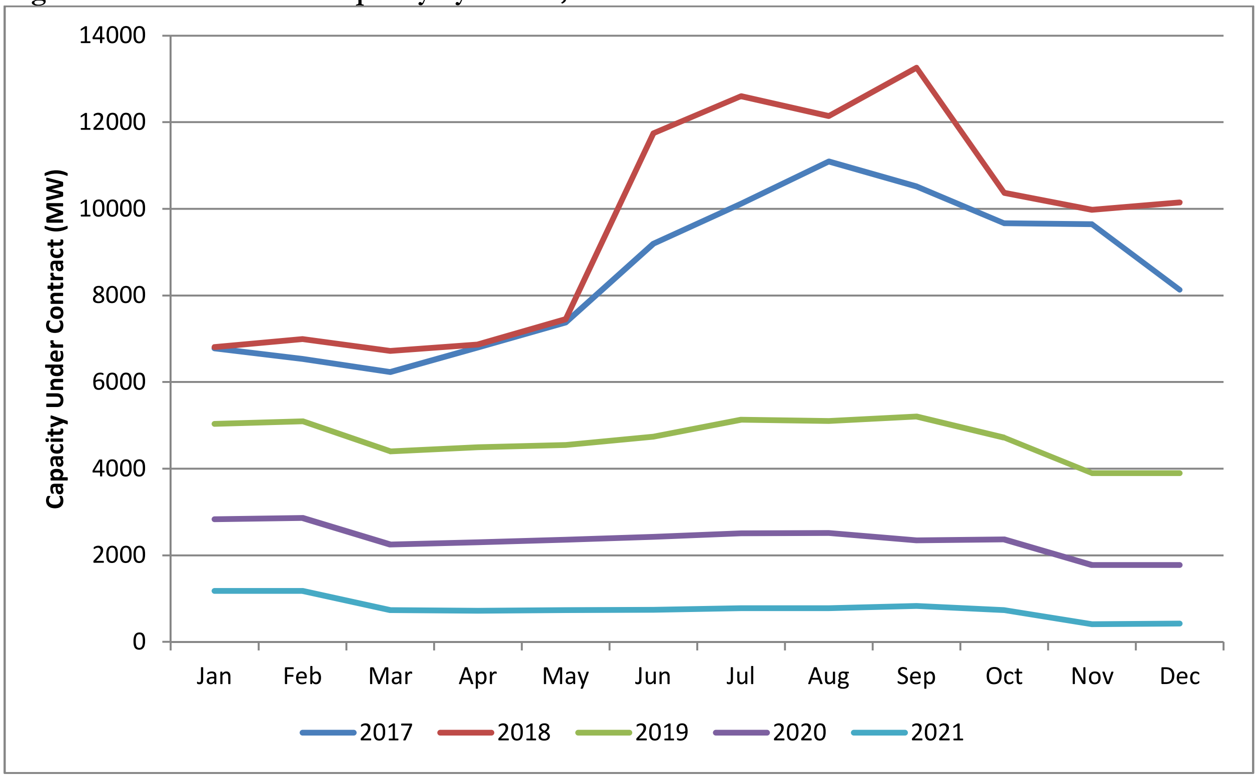


	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
All Prices	$2.52	$2.51	$2.56	$2.50	$2.51	$2.63	$3.15	$3.13	$2.95	$2.58	$2.53	$2.61
NP 26 Prices	$2.05	$2.07	$2.02	$1.97	$2.01	$2.10	$2.80	$2.76	$2.46	$2.02	$1.92	$1.93
SP 26 Prices	$3.25	$3.20	$3.27	$3.25	$3.19	$3.25	$3.50	$3.50	$3.49	$3.19	$3.12	$3.31

Source: 2017-2021 Price Data submitted by the LSEs

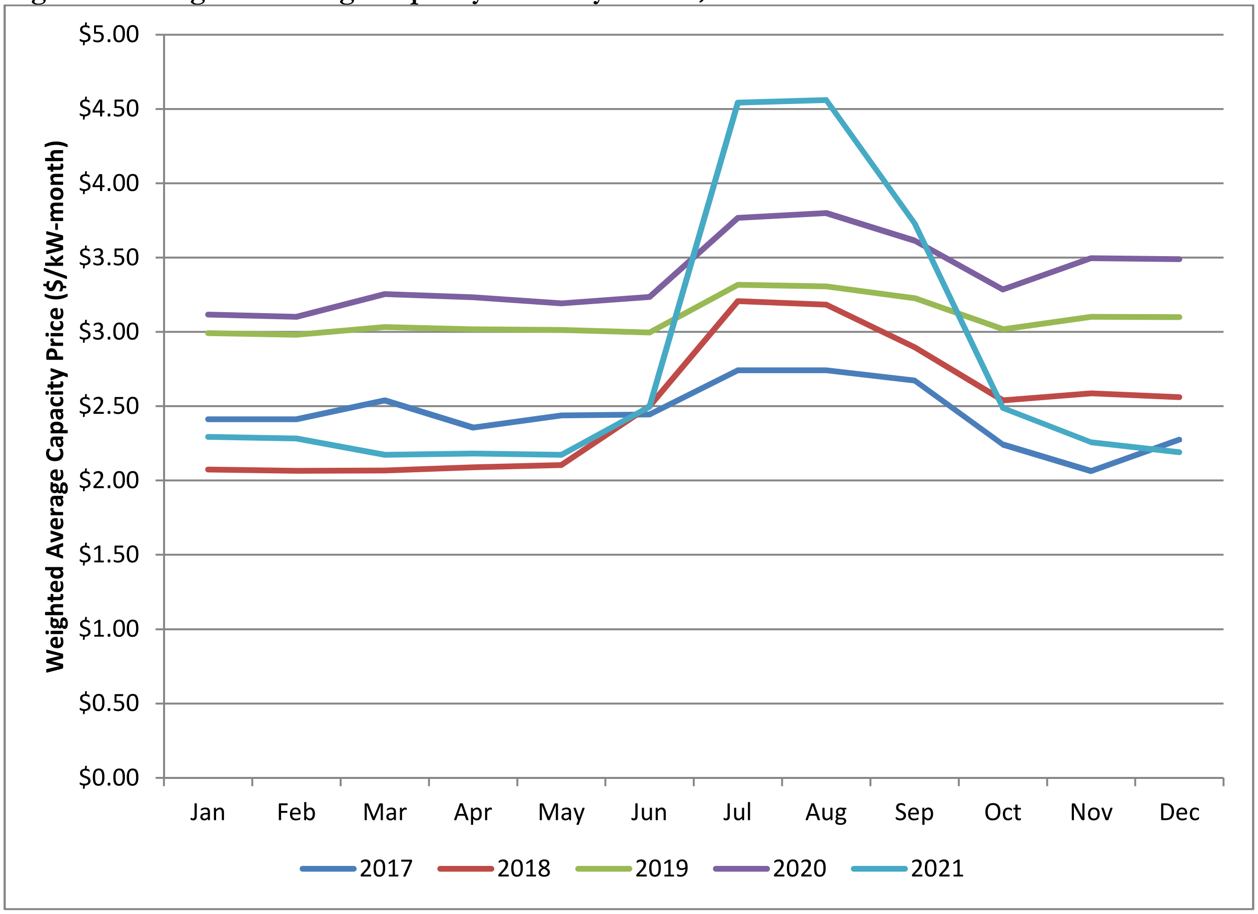
Figure 9 graphs the contracted capacity by months and year. Total capacity contracted in the summer is higher in 2018 than 2017. There is also more contracted capacity overall in 2018 than 2017.

Figure 9. Contracted RA Capacity by Month, 2017- 2021



Source: 2017-2021 Price Data submitted by the LSEs

Figure 10. Weighted Average Capacity Prices by Month, 2017-2021



Source: 2017-2021 Price Data submitted by the LSEs

Figure 10 graphs the weighted average capacity prices by month and year. Prices are higher during the summer months for each year. It also appears that further out years have higher prices for the summer months. This may indicate that years in the more distant future may have more constrained supply in the summer months than the closer future years.

4.2 CAISO Out of Market Procurement - RMR Designations

The CAISO performs an annual RMR study to identify which generator resources are needed on-line to reliably serve the local area load. 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 during the relevant compliance year. RMR resources are placed into two classes: Condition 1 contracts are allowed to operate in the energy market even if not dispatched by the CAISO for reliability purposes, and Condition 2 units are not allowed to operate in the energy market but are under the full dispatch of the CAISO for reliability purposes. Both types of RMR contracts are paid for by all customers in the transmission area.

Condition 1 units are able to competitively earn revenue in the energy market in addition to the capacity payments under the RMR Agreement. In D.06-06-064, the CPUC ordered that capacity from Condition 1 RMR contracts be allocated to LSEs to count towards the LSEs' local RA obligations only, while Condition 2 RMR units may be counted towards both the system and local RA obligations. Because they are able to participate in the market, Condition 1 units are allowed to sell their system RA credit to a third party. This decision also 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,[27] local RA requirements began to supplant RMR contracting for the 2007 compliance year, and a significant decline in 2007 RMR designations occurred. That trend continued through the 2011 compliance year, with only one remaining RMR contract (with the Oakland Power Plant).

In 2016, the RMR agreements for the Huntington Beach Synchronous condensers and Dynegy Oakland, LLC generating units were extended through calendar year 2017 to ensure reliability.[28] The Huntington Beach synchronous condensers will continue to run in order to provide reactive support to the San Diego and LA Basin areas. This is related to the SONGS closure and to mitigate voltage issues. Dynegy Oakland, LLC generating units 1, 2, and 3 are extended to ensure local reliability service to Oakland, California.

In 2017, for the 2018 compliance year, three units received RMR Condition 2 designations. Calpine Corporation's Feather River Energy Center (45 MW) and Yuba City Energy Center (46 MW), as well as Metcalf Energy Center (570 MW), were designated as Condition 2 RMR resources for Other PG&E Areas and Bay Area local areas, respectively.

4.3 CAISO Out of Market Procurement – CPM Designations

CAISO implemented the Capacity Procurement Mechanism (CPM) effective April 1, 2011 to procure capacity to maintain grid reliability 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; and
- 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.[29]

Eligible capacity is limited to resources that are not already under a contract to be a 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 reliability concern.

Under the exceptional dispatch CPM, CAISO can procure resources at an initial term of 30 days. The term can be extended beyond the initial 30 day period if CAISO determines that the

[27] D.06-06-064, Section 3.3.7.1.

[28] Board Decision on conditional approval to extend existing RMR contracts for 2017, August 31, 2016 http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=D98FF59D-930A-494C-8AFD-C575DDDBF7C1
Update on Results of RMR Contract Extension for 2017
http://www.caiso.com/Documents/Update_Results_RMRContractExtension_2017-Oct2016.pdf

[29] CAISO Reliability BPM, version 36, page 139.
https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Reliability%20Requirements

circumstances leading to exceptional dispatch continue to exist. If a resource at-risk of retirement qualifies under CAISO's list of criteria, the resource can be procured from a minimum commitment of 30 days to a maximum commitment of one year within the current RA compliance year.[30]

The price of CPM is based on the going forward fixed costs of a reference resource. It was set at the higher of the resource's actual going forward cost or $55/kW-year beginning on April 1, 2011. Effective on February 16, 2012, the CPM price was increased to $67.50/kW-year when FERC issued an order that approved the settlement in the CAISO's CPM proceeding. Effective February 16, 2014, the CPM price was increased to $70.88/kW-year. The CPM price was set to expire in February 2016. Beginning November 1, 2016, CAISO tariff replaced the CPM price with a Competitive Solicitation Process (CSP). The tariff revisions include 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.[31] The Competitive Solicitation Process applies to all potential CPM designations, except risk of retirement designations.

Table 10 shows CAISO's CPM designation from 2012 to 2017.[32]

Table 10. CAISO CPM Designation from 2012-2017

Resource ID	MW	CPM Type	Term (in days)	Start Date	End Date	Estimated Capacity Cost
HNTGBH_7_UNIT 1	20	Exceptional Disp.	20	2/8/2012	3/8/2012	$121,810
HNTGBH_7_UNIT 1	98	Exceptional Disp.	60	3/1/2012	4/29/2012	$1,255,748
ENCINA_&_EA4	300	Exceptional Disp.	60	3/1/2012	4/29/2012	$3,844,125
HNTGBH_7_UNIT 3	225	Sig Event	30	5/11/2012	6/9/2012	$1,441,547
HNTGBH_7_UNIT 4	215	Sig Event	30	5/11/2012	6/9/2012	$1,377,478
HNTGBH_7_UNIT 3	225	Sig Event	60	6/10/2012	8/8/2012	$2,883,094
HNTGBH_7_UNIT 4	215	Sig Event	60	6/10/2012	8/8/2012	$2,754,956
HNTGBH_7_UNIT 3	225	Sig Event	84	8/9/2012	10/31/2012	$4,036,331

[30] CAISO Capacity Procurement Mechanism Overview Presentation, March 3, 2011, http://www.caiso.com/Documents/CapacityProcurementMechanismOverview.pdf
[31] CAISO 2016 Fourth Quarter Market Issues and Performance Report, March, 2017, page 68, http://www.caiso.com/Documents/2016FourthQuarterReport-MarketIssuesandPerformanceMarch2017.pdf
[32] CAISO Capacity Procurement Mechanism Report, http://www.caiso.com/market/Pages/ReportsBulletins/Default.aspx

HNTGBH_7_UNIT 4	215	Sig Event	84	8/9/2012	10/31/2012	$3,856,939
HNTGBH_7_UNIT 1	225.75	Sig Event	30	9/5/2012	10/4/2012	$1,446,352
Inland Empire Unit 2	79.99	Exceptional Disp.	60	11/4/2012	1/2/2013	
MORBAY_7_UNIT 4	50.01	Exceptional Disp.	60	2/22/2013	4/22/2013	$640,815
HNTGBH_7_UNIT 2	163	Exceptional Disp.	60	9/1//2013	10/30/2013	$2,088,642
HIDSRT_2_UNITS	181	Exceptional Disp.	30	2/6/2014	3/7/2014	$1,159,644
Hanford Peaker Plant	20	Exceptional Disp.	60	5/26/2014	7/24/2014	
MOSSLD_2_PSP2	490	Exceptional Disp.	60	10/2/2014	12/1/2014	$6,593,139
MOSSLD_7_UNIT 6	52	Exceptional Disp.	30	6/30/2015	7/29/2015	$349,840
OILDAL_1_UNIT 1	40	Exceptional Disp.	60	7/15/2015	9/12/2015	$538,215
MNDALY_7_UNIT 2	20.01	Local Reliability Issue	60	11/8/2016	1/7/2017	$252,526
MNDALY_7_UNIT 3	130	system emergency	30	11/9/2016	12/9/2016	$820,300
SENTNL_2_CTG1	1	System emergency	30	11/9/2016	12/9/2016	$6,310
SENTNL_2_CTG2	1	System emergency	30	11/9/2016	12/9/2016	$6,310
SENTNL_2_CTG3	1	System emergency	30	11/9/2016	12/9/2016	$6,310
SENTNL_2_CTG6	1	System emergency	30	11/9/2016	12/9/2016	$6,310
PIOPIC_2_CTG1	102.67	System emergency	30	11/9/2016	12/9/2016	$647,847
PIOPIC_2_CTG2	102.67	System emergency	30	11/9/2016	12/9/2016	$647,847
PIOPIC_2_CTG3	102.67	System emergency	30	11/9/2016	12/9/2016	$647,847
LMEC_1_PL1X3	89.79	Local Reliability Issue	60	12/14/2016	2/13/2017	$1,133,149
DELTA_2_PL1X4	114	Local Reliability Issue	60	12/14/2016	2/13/2017	$1,438,680
MOSSLD_2_PSP1	141.04	System emergency	30	12/18/2016	1/17/2017	$889,962

SBERDO_2_PSP3	36.37	Local Reliability Issue	60	12/19/2016	2/18/2017	$138,206
PIOPIC_2_CTG2	50	system emergency	30	2/6/2017	3/7/2017	$315,500
OTMESA_2_PL1X3	155.01	System Emergency	10	5/22/2017	5/31/2017	$208,013
MNDALY_7_UNIT 2	20.01	Exceptional Disp.	30	6/18/2017	7/17/2017	$126,263
MNDALY_7_UNIT 1	20.01	Exceptional Disp.	30	6/18/2017	7/1/2017	$54,714
ELCAJN_6_LM6K	24.87	Local Reliability Issue	60	7/27/2017	9/24/2017	$6.31/kW-month
MNDALY_7_UNIT 3	119.4	System Reliability Issue	30	10/24/2017	11/22/2017	$6.31/kW-month
MNDALY_7_UNIT 1	215	Local Reliability Issue	60	12/5/2017	2/2/2018	$2,700,000
MNDALY_7_UNIT 2	215	Local Reliability Issue	60	12/6/2017	2/3/2018	$2,700,000
MNDALY_7_UNIT 3	130	Local Reliability Issue	60	12/7/2017	2/4/2018	$1,600,000
MOSSLD_2_PSP1	510	Local Reliability Issue	365	1/1/2018	12/31/2018	
ENCINA_7_EA4	272	Local Reliability Issue	365	1/1/2018	12/31/2018	
ENCINA_7_EA5	273	Local Reliability Issue	365	1/1/2018	12/31/2018	

As Table 10 shows, for the first time since the inception of the RA program, there were CPM designations for Moss Landing, Encina Unit 4, and 5 due to LSEs' collective as well as individual capacity deficiencies as a result of CAISO's 2018 Year Ahead local residual analysis. Most of the other CPM designations were due to significant events and exceptional dispatch. Huntington Beach Units 3 and 4 received CPM designations due to the outage of SONGS in the summer of 2012. In 2016, all the CPM designations were triggered by exceptional dispatch in the intra-monthly CSP.

4.4 IOU Procurement for System Reliability and Other Policy Goals

D.06-07-029 adopted a process known as the CAM, which allows the Commission to designate IOUs to procure new generation within an IOU's distribution service territory. Under CAM, all related costs and benefits would be allocated to all benefiting customers, including bundled utility customers, direct access customers, and community choice aggregator customers. The LSEs serving these customers are allocated the capacity in each service territory, which are applied towards meeting the LSE's RA requirement. The LSEs receiving a portion of the CAM capacity pay only for the net cost of the capacity, which is the net of the total cost of the power purchase contract price minus the energy revenues associated with the dispatch of the contract.

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 11 shows which conventional generation resources qualify for CAM and provides the scheduling resource ID, the contract dates that the CAM was approved to cover, the authorized IOU, and August NQC values. The list includes all conventional generation resources subject to the CAM mechanism since its inception.

Table 11. 2013-2017 Resources Authorized for CAM Due to Reliability

2013 Resources Authorized for CAM Due to Reliability

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
BARRE_6_PEAKER	8/1/2007	NA	SCE	47.00
BUCKBL_2_PL1X3	8/1/2010	7/31/2020	SCE	490.00
CENTER_6_PEAKER	8/1/2007	NA	SCE	47.00
ETIWND_6_GRPLND	8/1/2007	NA	SCE	46.00
HINSON_6_LBECH1-HINSON_6_LBECH4	6/1/2007	7/31/2017	SCE	260.00
MIRLOM_6_PEAKER	8/1/2007	NA	SCE	46.00
VESTAL_2_WELLHD	2/1/2013	5/31/2022	SCE	49.00
WALCRK_2_CTG1-WALCRK_2_CTG5	6/1/2013	5/31/2023	SCE	479.32
SENTNL_2_CTG1 - SENTNL_2_CTG8	8/1/2013	7/31/2023	SCE	728.80
ELSEGN_2_UN1011 & ELSEGN_2_UN2021	8/1/2013	7/31/2023	SCE	550.00
COCOPP_2_CTG1-COCOPP_2CTG4	7/1/2013	4/30/2023	PG&E	563.64

2014 Resources Authorized for CAM Due to Reliability (Incremental)

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
ESCNDO_6_PL1X2	5/1/2014	12/31/2038	SDG&E	48.71

2015 Resources Authorized for CAM Due to Reliability (Incremental)

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
MNDALY_6_MCGRTH	11/1/2014	NA	SCE	47.20

2017 Resources Authorized for CAM Due to Reliability (Incremental)

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

CHINO_2_APEBT1	2/1/2017	12/30/2026	SCE	20.00
Powin Energy – Milligan ESS 1	7/1/2017	12/31/2026	SCE	2.00
ESCNDO_6_EB1BT1	3/6/2017	UOG	SDG&E	10.00
ESCNDO_6_EB2BT2	3/6/2017	UOG	SDG&E	10.00
ESCNDO_6_EB3BT3	3/6/2017	UOG	SDG&E	10.00
ELCAJN_6_EB1BT1	4/1/2017	UOG	SDG&E	7.50
PIOPIC_2_CTG1	6/1/2017	12/31/2037	SDG&E	106.00
PIOPIC_2_CTG2	6/1/2017	12/31/2037	SDG&E	106.00
PIOPIC_2_CTG3	6/1/2017	12/31/2037	SDG&E	106.00
MIRLOM_2_MLBBTA	7/1/2017	6/30/2027	SCE	10.00
MIRLOM_2_MLBBTB	7/1/2017	6/30/2027	SCE	10.00

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

D.10-12-035[33] 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 the GHG emissions consistent with the ARB climate change scoping plan. 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.[34] The adopted cost allocation mechanism was almost identical to what was adopted in the 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, DA, and CCA customers. The RA benefits associated with the CHP contract are also allocated to all customers paying the net capacity costs.[35]

In 2016, PG&E had a total of 24 CHP contracts whose costs and benefits were allocated to all customers, amounting to 1,263 MW of RA credit. In 2016, SCE had 10 CHP contracts that were allocated, amounting to 882 MW of RA credit. In 2017, PG&E had one CHP contract that was allocated, amounting to 24.57 MW of RA credit. SCE had 3 CHP contracts that were allocated, amounting to 39.86 MW of RA credit. SDG&E had one CHP contract that was allocated, amounting to 6.39 MW of RA credit allocated. Table 12, below, lists the CHP resources whose RA capacity credits were allocated from 2013 to 2018.

Table 12. CHP Resources Allocated for CAM 2013-2018

CHP Resources that Received RA Credits in 2013

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
KERNFT_1_UNITS	4/1/2012	11/30/2020	PG&E	47.00
SIERRA_1_UNITS	4/1/2012	11/30/2020	PG&E	47.00
DOUBLC_1_UNITS	4/1/2012	11/30/2020	PG&E	47.00
SARGNT_2_UNIT	4/1/2012	12/31/2016	PG&E	31.81
SALIRV_2_UNIT	4/1/2012	12/31/2016	PG&E	30.83
COLGA1_6_SHELLW	4/1/2012	12/31/2016	PG&E	35.70

[33] http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/128624.htm
[34] CHP Program Settlement Agreement Term Sheet 13.1.2.2
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124875.PDF
[35] 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."

MIDSET_1_UNIT 1	4/1/2012	12/31/2016	PG&E	33.14
BDGRCK_1_UNITS	7/1/2012	6/30/2015	PG&E	45.21
CHALK_1_UNIT	7/1/2012	6/30/2015	PG&E	44.58
MKTRCK_1_UNIT 1	7/1/2012	6/30/2015	PG&E	40.84
LIVOAK_1_UNIT 1	7/1/2012	6/30/2015	PG&E	44.40
UNVRSY_1_UNIT 1	8/1/2012	6/30/2015	PG&E	34.19
CONTAN_1_UNIT	8/1/2012	6/30/2015	PG&E	18.04
TEMBLR_7_WELLPT	8/1/2012	3/31/2015	PG&E	0.38
DEXZEL_1_UNIT	9/2/2012	7/1/2015	PG&E	28.25
TANHIL_6_SOLART	10/1/2012	9/30/2019	PG&E	10.35
FRITO_1_LAY	10/1/2012	9/30/2019	PG&E	0.08
KERNRG_1_UNITS	10/1/2012	9/30/2019	PG&E	1.23
CALPIN_1_AGNEW	11/1/2012	4/18/2021	PG&E	28.00
TXMCKT_6_UNIT	7/1/2012	9/30/2013	PG&E	3.74
TIDWTR_2_UNITS	8/1/2013	6/30/2015	PG&E	17.58

CHP Resources that Received RA Credits in 2014 (Incremental)

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
OROVIL_6_UNIT	1/1/2014	10/14/2020	PG&E	7.5
OMAR_2_UNIT 1	1/1/2014	12/31/2020	PG&E	77.25
OMAR_2_UNIT 2	1/1/2014	12/31/2020	PG&E	77.25
OMAR_2_UNIT 3	1/1/2014	12/31/2020	PG&E	77.25
OMAR_2_UNIT 4	1/1/2014	9/30/2020	PG&E	77.25
LMEC_1_PL1X3	1/1/2014	12/31/2017	PG&E	135.00
LGHTHP_6_QF	12/10/2012	12/31/2014	SCE	0.78
TENGEN_2_PL1X2	7/2/2012	7/1/2015	SCE	34.99
HOLGAT_1_BORAX	6/1/2012	7/1/2015	SCE	20.03
SEARLS_7_ARGUS	7/13/2013	7/1/2015	SCE	12.39
LMEC_1_PL1X3	1/1/2014	12/31/2021	SCE	135
GILROY_1_UNIT	1/1/2014	12/31/2018	SCE	52.5
SYCAMR_2_UNIT 1	1/1/2014	12/31/2021	SCE	56.53
SYCAMR_2_UNIT 2	1/1/2014	12/31/2021	SCE	56.54
SYCAMR_2_UNIT 3	1/1/2014	12/31/2021	SCE	56.53
SYCAMR_2_UNIT 4	1/1/2014	12/31/2021	SCE	56.53
ARCOGN_2_UNITS	10/1/2013	6/30/2015	SCE	274.89

CHP Resources that Received RA Credits in 2015 (Incremental)

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
STOILS_1_UNITS	10/1/2014	7/31/2026	PG&E	1.72
SMPRIP_1_SMPSON	4/1/2015	5/31/2018	PG&E	45.6
BEARMT_1_UNIT	5/1/2015	4/30/2022	PG&E	44.58
SUNSET_2_UNITS	7/1/2015	12/31/2020	PG&E	218
BDGRCK_1_UNITS	5/1/2015	4/30/2022	PG&E	36.29
CHALK_1_UNIT	5/1/2015	4/30/2022	PG&E	36.53

MKTRCK_1_UNIT 1	5/1/2015	4/30/2022	PG&E	35.96
LIVOAK_1_UNIT 1	5/1/2015	4/30/2022	PG&E	41.14
TIDWTR_2_UNITS	7/1/2015	4/30/2022	PG&E	22.75
CHEVMN_2_UNITS	7/10/2014	12/31/2050	SCE	6.2
UNVRSY_1_UNIT 1	7/1/2015	6/30/2022	SCE	34.87
HOLGAT_1_BORAX	7/1/2015	6/30/2022	SCE	19.17
ARCOGN_2_UNITS	7/1/2015	6/30/2022	SCE	270.87
TENGEN_2_PL1X2	7/1/2015	6/30/2021	SCE	36.00

CHP Resources that Received RA Credits in 2016 (Incremental)

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
ETIWND_2_UNIT1	1/1/2016	4/23/2021	SCE	14.74
SNCLRA_2_UNIT1	4/1/2016	3/30/2023	SCE	13.61
ELKHIL_2_PL1X3	1/1/2016	12/31/2020	SCE	200.00
DEXZEL_1_UNIT	12/1/2015	3/31/2022	PG&E	18.65

CHP Resources that Received RA Credits in 2017 (Incremental)

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
GRZZLY_1_BERKLY	8/1/2017	7/31/2024	PG&E	24.57
HINSON_6_CARBGN	12/30/2017	12/31/2020	SCE	29.30
SNCLRA_2_HOWLNG	4/1/2017	10/31/2023	SCE	7.63
VESTAL_2_UNIT1	4/1/2017	3/31/2026	SCE	2.93
SAMPSN_6_KELCO1	6/1/2017	6/2/2022	SDG&E	6.39

CHP Resources that Received RA Credits in 2018 (Incremental)

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
CHINO_6_CIMGEN	3/11/2018	3/10/2025	SCE	25.96

DRAM Resources that Received RA Credits in 2016

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
NA	6/1/2016	12/31/2016	PG&E	17.17
NA	6/1/2016	12/31/2016	SCE	20.32
NA	6/1/2016	12/31/2016	SDG&E	2.99

DRAM Resources that Received RA Credits in 2017

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
NA	1/1/2017	12/31/2017	PG&E	21.38
NA	1/1/2017	12/31/2017	SCE	56.20
NA	1/1/2017	12/31/2017	SDG&E	11.92

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

Event-based DR resources are also treated as an RA credit towards meeting RA obligations. The costs for most DR programs are allocated through the distribution charge which means that most DR programs, other than SCE's Save Power Day (SPD) and Critical Peak Pricing (CPP) programs, are paid for by bundled, direct access, and community choice aggregator customers. The RA credit associated with DR is calculated using the CPUC-adopted Load Impact Protocols. The IOUs/DR providers submit the ex-ante load impact values associated with each 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 determined to be final, the DR RA credits are posted on the CPUC's RA compliance website and then allocated to all LSEs for the coming compliance year.

Beginning in 2013, the RA program implemented the adopted Maximum Cumulative Capacity (MCC) DR bucket structure.[36] An additional tab was added to the RA reporting template specifically for DR resources. LSEs are still sent their annual DR allocations through the year-ahead process. Once the DR allocations are sent to all benefiting LSEs in the annual allocations, the DR values are inserted into the allocation tab of the RA template which then auto-populates the DR values to the DR resource tab of the workbook. The DR values are combined with other physical resources reported in the workbook and are counted towards meeting the LSE's RA obligation verses reducing the LSE's RA obligation. LSEs can also enter additional DR resources that they have procured on this tab.

In 2016, a total of 2,004 MW of DR RA credit was allocated to benefiting LSEs to meet August RA obligations. These DR values include an added Transmission and Distribution (T&D) loss factor and an added 15% planning reserve margin.

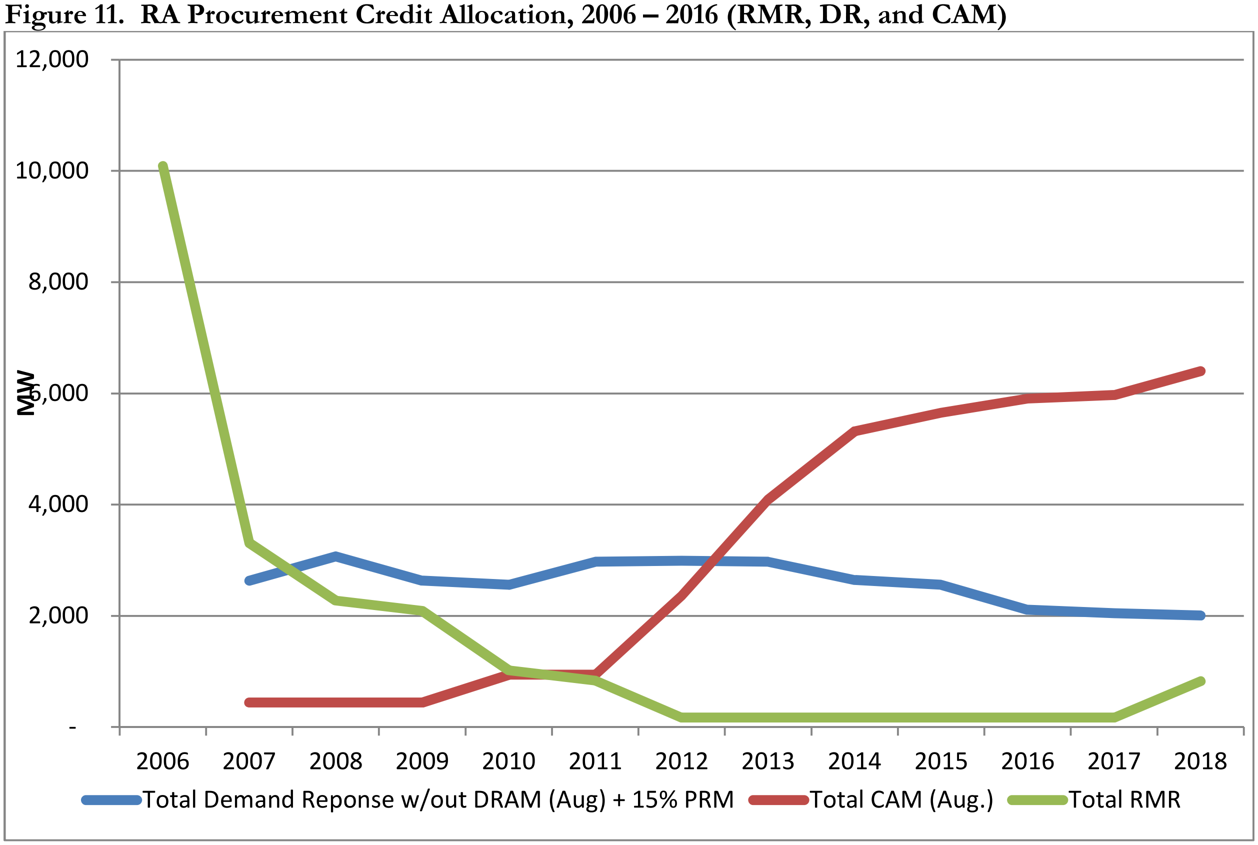
Table 13 and Figure 11 illustrate the amount and type of procurement credit that have been allocated since the beginning of the RA program. The graph reflects the decline in RMR units until 2018 and the increase in CAM units. DR RA credits have declined slightly since 2013. The total amount of capacity procured through DR, CAM, and RMR for August 2017 was 8,179 MW. This is 17% of the total CPUC-jurisdictional LSE obligation for August 2017 (47,348 MW). In August 2018, total CAM procurement reached 6,402 MW where RMR procurement increased from 165 MW in 2017 to 826 MW in 2018 (CPUC jurisdictional LSEs were allocated 746.18 MW of the 826 MW in August 2018).

[36] D.12-06-025.

Table 13. DR, CAM, and RMR Allocations (MW)

		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
DR Procurement	SCE			1,705	1,616	1,613	1,838	2,067	2,195	1,615	1,626	1,480	1,437	1,397
	PG&E			1018	912	846	888	744	783	933	807	565	566	562
	SDG&E			346	104	97	241	177	135	96	121	53	37	40
	Total DR w/out DRAM (Aug)		**2,628**	**3,069**	**2,633**	**2,556**	**2,967**	**2,987**	**3,114**	**2,644**	**2,554**	**2,105**	**2,045**	**2,004**
CAM Procurement	SCE		436	436	436	936	936	1,529	2,763	3,477	3,583	3,848	3,702	4,091
	PG&E							703	1,351	1,790	2,020	2,008	1,868	1,897
	SDG&E							130		49	49	49	399	413
	Total CAM (Aug)		**436**	**436**	**436**	**936**	**936**	**2,362**	**4,114**	**5,316**	**5,652**	**5,905**	**5969**	**6402**
RMR Procurement	SCE	1,390												
	PG&E	6,151	1,348	1,303	1,263	709	527	165	165	165	165	165	165	826
	SDG&E	2,549	1,961	973	828	311	311							
	Total RMR	**10,090**	**3,309**	**2,276**	**2,091**	**1,020**	**838**	**165**	**165**	**165**	**165**	**165**	**165**	**826**

Figure 11. RA Procurement Credit Allocation, 2006 – 2016 (RMR, DR, and CAM)



5 Process for Determining the NQC of RA Resources

Qualifying Capacity (QC) represents a resource's maximum capacity eligible to be counted towards meeting the CPUC's RA Requirement prior to an assessment of its deliverability. The CPUC adopted the current QC counting conventions, which are computed based on the applicable resource type, in D.10-06-036.[37] The applicable data sets and data conventions are laid out in the adopted QC methodology manual, which is posted on the CPUC website.[38] For dispatchable resources, the QC is based on the most recent Pmax test. The latest Pmax test is kept in the ISO's master file. For non-dispatchable hydro and geothermal resources, the QC methodology is based on historical production. CHP and biomass resources that can bid into the day ahead market, but are not fully dispatchable, receive QC values based on MW amount offered into the day ahead market. Wind and solar resources receive QC values based on effective load carrying capability (ELCC) modeling. The CPUC executes a subpoena for settlement quality meter and bidding data from the ISO and performs QC calculations for non-dispatchable and intermittent resources annually.

After the QC values are determined, the CAISO conducts a deliverability assessment to produce the net qualifying capacity (NQC) value of each resource. The difference between the QC and the NQC is the deliverability of the resource to aggregate California ISO load. When the QC for a resource exceeds the resource's deliverable capacity, the NQC is adjusted to the deliverable capacity value. The CAISO conducts the deliverability assessment for both new and existing resources two to three times a year pursuant to the Large Generator Interconnection Procedures (LGIP).[39] The August deliverability study is used to determine the annual NQC of a resource.

After the CAISO has completed the August deliverability study, a draft NQC list is posted and generators are typically given 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. Once posted, no changes are permitted to the list except for addition of new resources and correction of clerical errors.

5.1 New Resources and Retirements in 2017

While many new resources were added during 2017, overall capacity available decreased considerably. This was in large part due to the adoption of ELCC for 2018 which reduced August solar capacity by approximately 50%. Additionally, 3,851 MW of older gas and cogeneration facilities retired during 2017. While this was partially offset by 438 MW of new resources, overall 2017-2018 saw a significant decrease in available capacity.

Table 14 lists the new and retiring facilities for 2017. Net dependable capacity, as determined by the ISO, is also listed for new facilities as facilities 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. For example, in 2017, the net dependable capacity of facilities that came online was about 800 MW greater than the assigned NQC values.

[37] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/119856.htm (QC manual adopted as Appendix B).
[38] http://www.cpuc.ca.gov/General.aspx?id=6311
[39] The CAISO's deliverability assessment methodology is available at http://www.caiso.com/23d7/23d7e41c14580.pdf

Table 14. New NQC Resources Online in 2017[40]

Resource ID	Resource Name	Technology	NQC[41]	Net Dependable Capacity
AVENAL_6_AVSLR1	Avenal Solar 1	Solar PV	0.00	7.90
AVENAL_6_AVSLR2	Avenal Solar 2	Solar PV	0.00	7.90
BIGSKY_2_BSKSR6	Big Sky Solar 6	Solar PV	8.20	20.00
BIGSKY_2_BSKSR7	Big Sky Solar 7	Solar PV	8.20	20.00
BIGSKY_2_BSKSR8	Big Sky Solar 8	Solar PV	8.20	20.00
BIGSKY_2_SOLAR2	Big Sky Solar 4	Solar PV	34.02	40.00
BIGSKY_2_SOLAR4	Western Antelope Blue Sky Ranch B	Solar PV	17.07	20.00
BIGSKY_2_SOLAR6	Solverde 1	Solar PV	34.85	85.00
BLYTHE_1_SOLAR2	Blythe Green 1	Solar PV	0.00	20.00
CALFTN_2_SOLAR	California Flats North	Solar PV	53.30	130.00
COVERD_2_HCKHY1	Hatchet Creek	Hydro	3.00	6.89
COVERD_2_MCKHY1	Montgomery Creek Hydro	Hydro	1.26	2.80
COVERD_2_RCKHY1	Roaring Creek	Hydro	0.87	2.00
CUYAMS_6_CUYSR1	Cuyama Solar	Solar PV	16.40	40.00
DELAMO_2_SOLAR3	Golden Springs Building G	Solar PV	0.51	1.25
DELAMO_2_SOLAR4	Golden Springs Building F	Solar PV	0.53	1.30
DELAMO_2_SOLAR5	Golden Springs Building L	Solar PV	0.41	1.00
DELAMO_2_SOLAR6	Freeway Springs	Solar PV	0.82	2.00
ELCAJN_6_EB1BT1	Eastern BESS 1	Storage	7.50	7.50
ESCNDO_6_EB1BT1	Escondido BESS 1	Storage	10.00	10.00
ESCNDO_6_EB2BT2	Escondido BESS 2	Storage	10.00	10.00
ESCNDO_6_EB3BT3	Escondido BESS 3	Storage	10.00	10.00
FROGTN_1_UTICAA	Angels Powerhouse	Hydro	0.49	1.40
GALE_1_SR3SR3	Sunray 3	Solar PV	5.66	13.80
GIFENS_6_BUGSL1	Burford Giffen	Solar PV	8.20	20.00
GLDFGR_6_SOLAR1	Portal Ridge B	Solar PV	8.20	20.00
GLDFGR_6_SOLAR2	Portal Ridge C	Solar PV	4.67	11.40
HATLOS_6_BWDHY1	Bidwell Ditch	Hydro	0.87	2.00
JACMSR_1_JACSR1	Jacumba Solar Farm	Solar PV	8.20	20.00
LASSEN_6_UNITS	Honey Lake Power	Biomass	30.00	30.00
LITLRK_6_SOLAR3	One Ten Partners	Solar PV	0.82	2.00
MAGUND_1_BKISR1	Bakersfield Industrial 1	Solar PV	0.00	1.00
MAGUND_1_BKSSR2	Bakersfield Solar 1	Solar PV	2.15	5.25
MANTEC_1_ML1SR1	Manteca Land 1	Solar PV	0.00	1.00

[40] This list does not include the many new demand response resources that have been added to the NQC list as demand response is integrated into the CAISO market.
[41] August NQC values are reported for facilities with NQC's that vary by month. If no NQC value is listed, that indicates an energy only facility.

MIRLOM_2_LNDFL	Milliken Landfill Solar	Solar PV	1.23	3.00
MIRLOM_2_MLBBTA	Mira Loma BESS A	Storage	10.00	10.00
MIRLOM_2_MLBBTB	Mira Loma BESS B	Storage	10.00	10.00
MSOLAR_2_SOLAR2	Mesquite Solar 2	Solar PV	41.33	100.81
MURRAY_6_UNIT	Grossmont Hospital	Cogeneration	0.00	4.12
NOVATO_6_LNDFL	Redwood Renewable Energy	Biogas	3.28	3.90
OAK L_1_GTG1	MWWTP PGS 2 - Turbine	Biogas	0.00	4.60
OASIS_6_SOLAR3	Soccer Center	Solar PV	0.00	3.00
OROLOM_1_SOLAR1	Oro Loma Solar 1	Solar PV	0.00	10.00
OROLOM_1_SOLAR2	Oro Loma Solar 2	Solar PV	0.00	10.00
PAIGES_6_SOLAR	Paige Solar	Solar PV	0.00	20.00
PBLOSM_2_SOLAR	Pear Blossom	Solar PV	3.90	9.50
PLAINV_6_NLRSR1	North Lancaster Ranch	Solar PV	0.00	20.00
PNCHVS_2_SOLAR	Panoche Valley Solar	Solar PV	25.42	240.00
RECTOR_2_CREST	Rector Aggregate Solar Resources	Solar PV	0.00	14.00
REDMAN_2_SOLAR	Lancaster East Avenue F	Solar PV	1.54	3.75
RICHMN_1_CHVSR2	Chevron 8.5	Solar PV	3.48	8.50
RICHMN_1_SOLAR	Chevron 2	Solar PV	0.82	2.00
RNDMTN_2_SLSPHY1	Silver Springs	Hydro	0.13	0.60
ROSMND_6_SOLAR	Lancaster B	Solar PV	1.23	3.00
SANTGO_2_MABBT1	Millikan Avenue BESS	Storage	2.00	2.00
SEGS_1_SR2SL2	Sunray 2	Solar PV	8.20	20.00
SKERN_6_SOLAR2	SKIC Solar	Solar PV	4.10	10.00
SMYRNA_1_DL1SR1	Delano Land 1	Solar PV	0.00	1.00
SPRGVL_2_CREST	Springerville Aggregate Solar Resources	Solar PV	0.00	14.00
TORTLA_1_SOLAR	Longboat Solar	Solar PV	8.20	20.00
TRNQL8_2_AZUSR1	Tranquillity 8 Azul	Solar PV	0.00	20.00
USWND2_1_WIND3	Golden Hills C	Wind	12.19	46.00
VEAVST_1_SOLAR	Community Solar	Solar PV	0.00	14.40
WHITNY_6_SOLAR	Whitney Point Solar	Solar PV	0.00	20.00
WLDWD_1_SOLAR2	Wildwood Solar 2	Solar PV	6.15	15.00
WOODWR_1_HYDRO	Quinten Luallen	Hydro	0.00	7.30
		Total	**437.6**	**1263.87**

Table 15. Resources that Retired in 2017

Resource ID	Resource Name	Technology	NQC
BRDWAY_7_UNIT 3	Broadway Unit 3	Thermal	65.00
CBRLLO_6_PLSTP1	Point Loma Sewage Treatment Plant	Biomass	2.53
COLGA1_6_SHELLW	Coalinga Cogeneration Company	Cogeneration	34.70
CONTAN_1_UNIT	Graphic Packaging Cogen	Cogeneration	27.70

ELCAJN_7_GT1	El Cajon	Peaker	16.00
ENCINA_7_EA1	Encina Unit 1	Thermal	106.00
ETIWND_7_MIDVLY	Mn Mid Valley Genco Llc	Biomass	1.67
FAIRHV_6_UNIT	Fairhaven Power Co.	Biomass	13.58
FLOWD2_2_UNIT 1	Small QF Aggregation - Livermore	Wind	3.18
FROGTN_7_UTICA	Utica Power Hydro Aggregate	Hydro	0.00
GOLDHL_1_QF	Small QF Aggregation - Placerville	Wind	0.00
HARBGN_7_UNITS	Harbor Cogen Combined Cycle	Thermal	100.00
HATLOS_6_QFUNTS	Hat Creek Hydro QF Units	Hydro	1.14
INLDEM_5_UNIT 2	Inland Empire Energy Center, Unit 2	Thermal	335.00
JAKVAL_6_UNITG1	Buena Vista	Biomass	13.86
KNGCTY_6_UNITA1	King City Energy Center, Unit #1	Peaker	44.60
LAROA1_2_UNITA1	LR1	Thermal	165.00
LGHTHP_6_ICEGEN	Carson Cogeneration	Cogeneration	48.00
MIDSET_1_UNIT 1	Midset Cogen. Co.	Cogeneration	32.60
MIRLOM_6_DELGEN	Corona Energy Partners Ltd.	Cogeneration	25.93
MOORPK_7_UNITA1	Weme- Simi Valley Landfill	Biomass	2.12
MOSSLD_7_UNIT 6	Moss Landing Unit 6	Thermal	754.00
MOSSLD_7_UNIT 7	Moss Landing Unit 7	Thermal	755.00
MRGT_7_UNITS	Miramar Combustion Turbine Aggregate	Peaker	36.00
OTAY_7_UNITC1	Otay 3	Biomass	1.78
PITTSP_7_UNIT 5	Pittsburg Unit 5	Thermal	312.00
PITTSP_7_UNIT 6	Pittsburg Unit 6	Thermal	317.00
PITTSP_7_UNIT 7	Pittsburg Unit 7	Thermal	530.00
SARGNT_2_UNIT	Sargent Canyon Cogen. Company	Cogeneration	32.25
VALLEY_7_BADLND	Badlands Landfill Gas to Energy Facility	Biomass	0.44
VALLEY_7_UNITA1	Wm Energy, El Sobrante Landfill	Biomass	2.56
WDFRDF_2_UNITS	West Ford Flat Aggregate	Geothermal	25.00
WOLFSK_1_UNITA1	Wolfskill Energy Center, Unit #1	Peaker	46.00
		Total	**3850.64**

Source: 2017-2018 NQC lists posted to the CAISO website[42]

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, can be found on the CEC website.[43]

[42] http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx and http://www.caiso.com/planning/Pages/ReliabilityRequirements/ReliabilityRequirementsArchive.aspx
[43] http://www.energy.ca.gov/sitingcases/all_projects.html

5.2 Aggregate NQC Values 2013 through 2018

Table 16 shows aggregate NQC values from the CAISO NQC lists for 2013 through 2018.[44] Available capacity on the 2018 NQC list decreased substantially as adoption of ELCC reduced the capacity value of solar resources significantly and two larger gas generators retired: Moss Landing 6-7 and Pittsburg 5-7. The total 2018 NQC (as reported on the CAISO NQC list) decreased by 6,482 MW from the 2017 NQC list. The NQC lists for both years saw large increases in the resources listed by the end of the year, as many new facilities became operational in 2016 and 2017, and demand response was 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 16. Final NQC Values for 2013 – 2018

Year	Total NQC (MW)	Total Number of Scheduling Resource IDs	Net NQC Change (MW)	Net Gain in CAISO IDs on List
2013	53,336	733		
2014	53,112	765	-224	32
2015	52,996	802	-116	37
2016	53,173	972	177	170
2017	55,871	1,097	2,698	125
2018	49,389	1,198	-6,482	101
2013-18			**-3,947**	**465**

Source: NQC lists from 2013 through 2018.

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

6 Compliance with RAR

CPUC staff continued the implementation of the RA program during 2017 and built on experience from past years.

6.1 Overview of the RA Filing Process

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

As in previous years, Energy Division hosted a workshop in August 2016 to discuss general compliance rules as well as to highlight changes in procedures and filing rules new to the 2017 compliance year. During the workshop, Energy Division reviewed the process of filling out the compliance templates and provided suggestions to help avoid errors that could lead to non-compliance. The templates also included detailed instructions tabs. The workshop, RA guide, and templates were all designed to assist LSEs in showing compliance with the RA program and to clarify any confusion that could lead to errors leading to non-compliance.

The final 2017 filing guide and templates were made available to LSEs in September 2016. Changes were made to implement the new RA rules adopted in D.16-06-045. As in previous years, the CPUC required all filings to be submitted simultaneously to the CAISO and CEC.

6.2 Compliance Review

CPUC staff, in coordination with the CEC and CAISO, reviewed all compliance filings received in accordance with comprehensive procedures that include: verifying timely arrival of the filings, matching resources listed against those of the NQC list, confirming compliance with local and Path 26 requirements, 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; the CAISO then helps Energy Division match these supply plans to the LSE filings. Energy Division verifies compliance, approves filings, and sends an approval letter to each LSE.

In 2017, CPUC staff continued to work closely with LSEs to resolve any questions regarding the RA filing process and templates. CPUC staff answered numerous questions raised by LSEs with special or unique circumstances. CPUC staff expects that working with the LSEs to reconcile differences and make revisions will continue to lead to fewer questions in the future and make the RA filing process smoother.

6.3 Enforcement and Compliance

The essence of the RA program is mandatory LSE acquisition of capacity to meet load and reserve requirements. The short timeframes in which the CPUC, CAISO, and CEC staff must verify that adequate capacity has been procured and, if necessary, complete backstop procurement creates a need for filings to arrive on time and 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. Until recently, the CAISO has not needed to engage in backstop procurement for collective and CPUC-jurisdictional LSE procurement deficiencies, this could occur more frequently if compliance is not strictly enforced.

6.4 Enforcement Actions in the 2006 through 2017 Compliance Years

Pursuant to Commission Resolution E-4195[45] and D.11-06-022, 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 17 summarizes enforcement actions and citations taken by the Commission since the inception of the RA program in 2006. From 2006 through 2017, the Commission issued 47 citations for violations and initiated 4 enforcement cases, citing a total penalty of $330,210 and collecting $325,210 from citations and $847,500 from enforcement cases. In 2017, the Commission issued six citations and took no enforcement action, ultimately citing a total penalty of $150,110 and collecting $150,110 from LSEs.

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

Table 17. Enforcement Summary Pursuant to the RA Program Since 2006

Compliance Year	Citations Issued	LSEs Cited	Citation Penalties	Enforcement Cases	LSEs Enforced	Enforcement Penalties
2006	1	Commerce Energy	$1,500	0		0
2007	3	3Phases; Commerce Energy; Amer. Util. Network	$5,000	1	CNE	$107,500
2008	7	3Phases (2);Commerce Energy (2); Corona DWP; Sempra Energy; Shell Energy	$17,000	1	Calpine	$225,000
2009	4	Commerce Energy (3); CNE	$26,500	1	CNE	$300,000
2010	5	Commerce Energy; Pilot Power (2), Dir. Energy Bus., SDG&E	$25,500	0		0
2011	2	Liberty Power; Tiger Nat Gas	$7,000	1	PG&E	$215,000
2012	4	Glacial Energy of CA, Shell Energy, SDG&E, Direct Energy Business	$14,600	0		0
2013	5	SDG&E, Commerce Energy, 3 Phases, Liberty Power (2)	$26,500	0		0
2014	1	3 Phases	$5,000	0		0
2015	6	3 Phases (2), Commerce Energy (2), EDF Industrial, Glacial Energy	$38,000	0		0
2016	3	Tiger Natural Gas, Glacial Energy, Shell Energy	$13,500	0		0
2017	6	Commercial Energy of Montana (2), CleanPowerSF, Southern California Edison, Direct Energy Business, Tiger Natural Gas	$150,110	0		0
Total	47		$330,210	4		$847,500

Appendix

List of CPUC Jurisdictional LSEs 2017

1. Pacific Gas & Electric
2. Southern California Edison
3. San Diego Gas & Electric
4. 3 Phases Renewables Inc.
5. Just Energy Solutions, Inc.
6. Commercial Energy of Montana
7. Constellation New Energy Inc.
8. Calpine Power America-CA, LLC
9. Direct Energy Business, LLC
10. EDF Industrial Power Services, LLC
11. Agera Energy LLC
12. Liberty Power Holdings, LLC
13. Marin Clean Energy
14. Calpine Energy Solutions, LLC
15. Pilot Power Group, Inc.
16. Shell Energy North America
17. Sonoma Clean Power Authority
18. Tiger Natural Gas, Inc.
19. The Regents of the University of California
20. Lancaster Choice Energy
21. CleanPowerSF
22. Peninsula Clean Energy Authority
23. American PowerNet Management
24. Silicon Valley Clean Energy Authority
25. Apple Valley Clean Energy
26. Redwood Coast Energy Authority
27. Pico Rivera Innovative Municipal Energy