The 2016 Resource Adequacy Report

Energy Division

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2016 Resource Adequacy Report

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Table of Acronyms

AS	Ancillary Services	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

2016 Resource Adequacy Report

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) 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. This capacity includes system RA and local RA, both of which are measured in megawatts (MWs). The annual and monthly System and Local 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 2016 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.14-10-010) 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 2016, the RA program successfully provided sufficient resources to meet peak load. The 2016 peak demand (for CPUC jurisdictional LSEs) was forecasted to occur in August 2016 at 43,921 MW.[2] The forward procurement obligation/RA obligation to meet peak demand in August totaled 50,510 MW[3] and LSEs collectively procured 50,710 MW[4] to meet expected system needs (which includes 15% reserve margin). Actual peak load for 2016 (for CPUC and non-CPUC jurisdictional LSEs) occurred on July 27, 2016 at 46,008 MW.[5]

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[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 46,008 MW. See http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

CPUC jurisdictional LSEs fulfilled their local RA obligations during the 2016 compliance year. 2016 local RA procurement obligations for CPUC-jurisdictional LSEs totaled 21,842 MW. These obligations were met with a monthly minimum of 23,160 MW. The local obligations were met with 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 2016, CAM, RMR and DR procurement comprised 16.8% 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 and has remained there since. DR procurement has declined since 2013.[9]

In early 2017, 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 2016 – 2020 compliance years. A total of 2,241 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 $3.10 kW-month.[10] The weighted average capacity price for capacity South of Path 26 is about 78% 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.

In 2016, 3,592 MW of new generation came online. These new generation resources were mostly renewable generators with the vast majority being solar Photovoltaic (PV).[13] The 318 MW Pio Pico gas generator and several energy storage facilities came on line as well. In addition, 2,335 MW of generation retired in 2016[14] resulting in an incremental increase of 1,257 MW of Net Qualifying Capacity (NQC).

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[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 4.
[10] See Table 7.
[11] See Table 9.
[12] See Table 8.
[13] See Table 14.
[14] See Table 15.

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,[15] the Commission issues citations or starts enforcement actions. In total, the Commission issued three citations for violations related to compliance year 2016 for a total of $13,500 and collected $8,500 in payments from LSEs from these citations.

[15] 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).

2 Changes to the RA Program for 2016

Decisions (D.)15-06-063 adopted several new rules for the 2016 compliance year, including the following:

A) Adopted transmission and distribution line loss assumptions and scenarios from the Long-Term Procurement Plans proceeding (currently Rulemaking 13-12-010) available at the time Energy Division allocates demand response Qualifying Capacity Values for the next Resource Adequacy compliance year shall be used for purposes of "grossing–up" Qualifying Capacity values for demand response resources to account for avoided line losses in the Resource Adequacy process.

B) The Qualifying Capacity Calculation Manual shall be revised to specify calculation of one set of technology factors for solar thermal facilities and another for photovoltaic facilities.

C) For the 2016 Resource Adequacy compliance year only, Qualifying Capacity for resources that come online in phases shall be based on historical production after the phase reaches commercial operation excluding test data. Remaining phases under construction will be assessed using technology factors and a megawatt-weighted average of each part shall comprise the total Qualifying Capacity of the facility.

D) For 2016 Resource Adequacy compliance year only, Energy Division will not calculate proxy data for generators whose performance history may be affected by scheduled or forced outages. Instead QC for non-dispatchable resources will be based on the entire three years of production data, regardless of outage history.

E) The QC definitions shall be modified to create a category called "Pre-Dispatch" to include Resource Adequacy resources that are capable of operating in accordance with day-ahead and pre-day-ahead scheduling instruction, but are not fully capable of responding to real-time dispatch instructions. The "Pre-Dispatch" RA resource classification will be restricted to QF Cogeneration facilities only, not other types of QF resources and not including any non-QF resources. QC for Pre-Dispatch facilities will be based on MW scheduled amounts, not settlement data.

F) Energy Division shall publish a list of the Cost Allocation Mechanism resources per Decision 06-07-029 (including capacity values and contract dates) that were included in the allocation on its Resource Adequacy compliance website.

G) Energy Division shall provide twelve distinct forecast values, one per month, for the full year-ahead Cost Allocation Mechanism-related (per Decision 06-07-029) capacity allocation forecasts. Energy Division shall provide load-serving entities with twelve monthly Cost Allocation Mechanism values as part of its annual year-ahead allocation.

H) Energy Division shall publish the following documents following the initial Resource Adequacy year-ahead allocations around the end of July in each year:

1. The five monthly dates and times of the California Independent System Operator system peak used in each load-serving entities' coincident calculation and the five monthly "OASIS" coincident peaks;

2. The California Energy Commission's step-by-step process for load forecast adjustment; and

3. Any discretionary adjustments made with a detailed explanation of the adjustment and why it was made (using proxy load data).

I) Each load-serving entity's (LSE's) local capacity requirement shall be capped at that LSE's system requirement in the monthly resource adequacy process.

J) Local Resource Adequacy requirements shall be capped at monthly system Resource Adequacy requirements.

3 Load Forecast and Resource Adequacy Program Requirements

The RA program requires its jurisdictional LSEs to demonstrate through monthly and annual compliance filings that they have sufficient capacity commitments to satisfy demand at all times to ensure system reliability.

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. Following this annual LSE submission, the CEC makes a series of adjustments to the LSE submitted load forecasts which form the final load forecast used for year-ahead RA compliance. This process also requires LSEs to submit monthly load forecasts to the CEC that account for load migration throughout the compliance year.

In order to establish the year-ahead load forecast used to set RA requirements, the CEC first calculates each LSE's specific monthly coincidence factors[16] using historic hourly load data (filed by the 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 are used to make each LSE's peak load forecast reflective of the LSE's contribution to load at the time of CAISO's peak load. 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 is done to evaluate 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 are significantly inconsistent with 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 are more than 1% divergent from the CEC's monthly weather normalized forecasts, a pro rata adjustment is made to bring it back within 1%.

The aggregated LSE forecasts are used by the CEC 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 the system annual and monthly RA obligations.

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[16] 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 2016 revised annual forecasts were due on August 19, 2015. 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 2016 process:

LSEs file historical load information	**March 20, 2015**
LSEs file 2016 year-ahead load forecast	**April 24, 2015**
LSEs receive 2016 year-ahead RA obligations	**July 31, 2015**
Final date to file revised forecasts for 2016	**August 19, 2015**
LSEs receive revised 2016 RA obligations	**September 11, 2015**

For 2016, CPUC staff sent initial allocations to LSEs on July 31, revised initial allocation on August 13, and final allocations to LSEs on September 11, 2015. 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 2016 compliance year, LSEs must submit a revised forecast two months prior to each compliance filing month.[17] 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[18] updated this process to allow for load forecast changes/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. It is important not to 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.

[17] Annual RA Filing Guides are available on the CPUC website: http://www.cpuc.ca.gov/General.aspx?id=6311
[18] 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 2016 and the adjustments that were made by the CEC across the three IOU service areas.[19] 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 2016 of 43,798, which represents a 4% decrease from the peak forecast of 45,747 MW in 2015.[20]

Table 1. 2016 Aggregated Load Forecast Data (MW) - Results of Energy Commission Review and Adjustment to the 2016 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)	29,837	28,690	28,447	29,896	33,526	38,923	43,345	45,848	41,564	34,518	29,801	30,530
CEC Adjustment for Plausibility/ Migrating Load	(46)	(55)	(95)	(130)	(227)	(357)	(27)	(379)	84	(195)	(293)	80
EE/DG Adjustment	(178)	(181)	(190)	(264)	(296)	(329)	(328)	(352)	(335)	(304)	(213)	(192)
Pro Rata Adjustment to CEC Forecast	0	0	0	13	54	41	58	30	81	0	0	0
Non-Coincident Peak Demand	**29,613**	**28,453**	**28,162**	**29,516**	**33,058**	**38,277**	**43,048**	**45,148**	**41,394**	**34,019**	**29,294**	**30,418**
Coincidence Adjustment	(1,096)	(843)	(710)	(1,027)	(942)	(1,414)	(1,666)	(1,350)	(2,095)	(1,319)	(969)	(955)
Final Load Forecast Used for Compliance	**28,517**	**27,610**	**27,452**	**28,489**	**32,115**	**36,863**	**41,381**	**43,798**	**39,299**	**32,700**	**28,326**	**29,463**

Source: CEC Staff.

3.1.2 Year-Ahead Plausibility Adjustments and Monthly Load Migration

Plausibility adjustments most commonly indicate mismatches between LSE forecasts of customer retention and the CEC's forecasts of each LSE's customer retention. Table 2 below illustrates the magnitude of monthly plausibility adjustments from 2011 through 2016 compliance years and reports the monthly plausibility adjustments to the monthly year-ahead forecast as a percentage for 2016.

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

[20] The 2015 RA report can be found at: http://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452221.

In 2016, the CEC's plausibility adjustments reduced total load for all months except September and December. In 2016, the CEC found that 11 of 21 ESPs and all IOUs required plausibility adjustments in at least one month, an increase over 2015 when four of 17 ESPs and all three IOUs required an adjustment. The 2016 monthly plausibility adjustments as a percentage of that month's aggregated year-ahead forecast ranged from 0.27% to -1.04%. The adjustments to ESP forecasts reflect uncertainty in assumptions with regards to the migration of direct access load. 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.

Table 2. CEC Plausibility Adjustments, 2011-2016 (MW)

Compliance Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	0	28	38	39	161	210	1,381	115	1,256	42	33	66
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
2016 Plausibility Adjustment /Load	-0.16%	-0.20%	-0.35%	-0.45%	-0.71%	-0.97%	-0.07%	-0.86%	0.21%	-0.60%	-1.04%	0.27%

Source: Aggregated year-ahead CEC load forecasts, 2011-2016.

Monthly load forecasts, which are adjusted for load migration, form the basis of monthly RA obligations. Table 3 shows the monthly total load forecasts and the monthly adjustments for 2016. 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 1.11% for September 2016. On a megawatt basis, the net monthly load migration adjustments ranged from -123 to 651 MW in 2016.

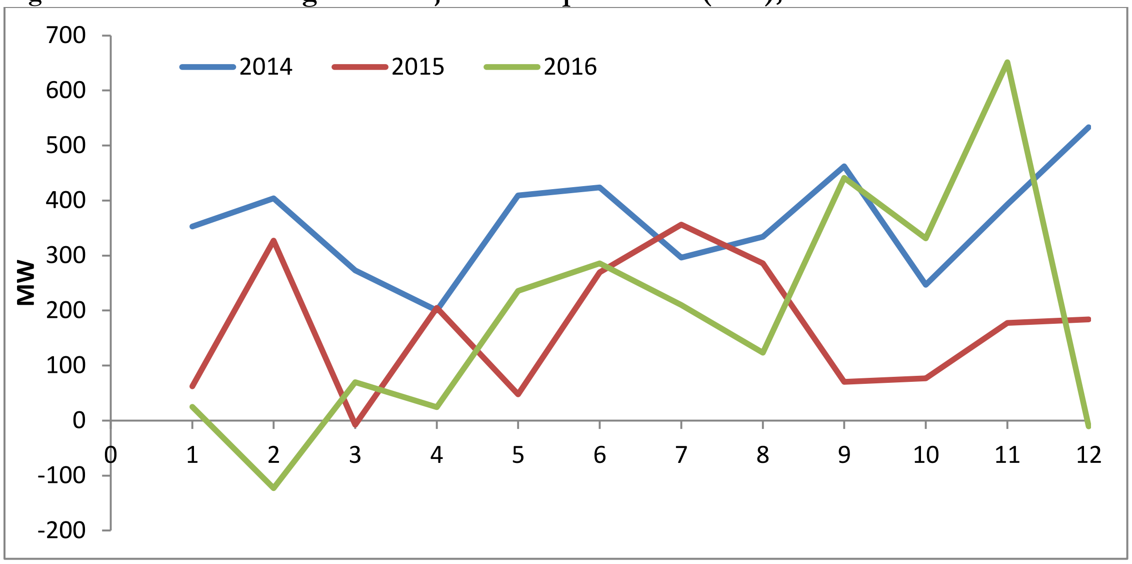
Table 3. Summary of Load Migration Adjustments in 2016 (MW)

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Forecasts , July 2015	28,517	27,610	27,452	28,489	32,115	36,863	41,381	43,798	39,299	32,700	28,326	29,463
Monthly Adjustments, 2016	25	-123	70	24	236	286	210	124	441	331	651	-11
Final Forecasts in Monthly RA Filings	28,542	27,487	27,522	28,513	32,351	37,149	41,592	43,921	39,740	33,031	28,977	29,452
Monthly Adjustments/ Final YA Load Forecast	0.09%	-0.45%	0.25%	0.09%	0.73%	0.77%	0.51%	0.28%	1.11%	1.00%	2.25%	-0.04%

Source: Aggregated load forecast adjustments submitted to the CEC and CPUC through 2016.

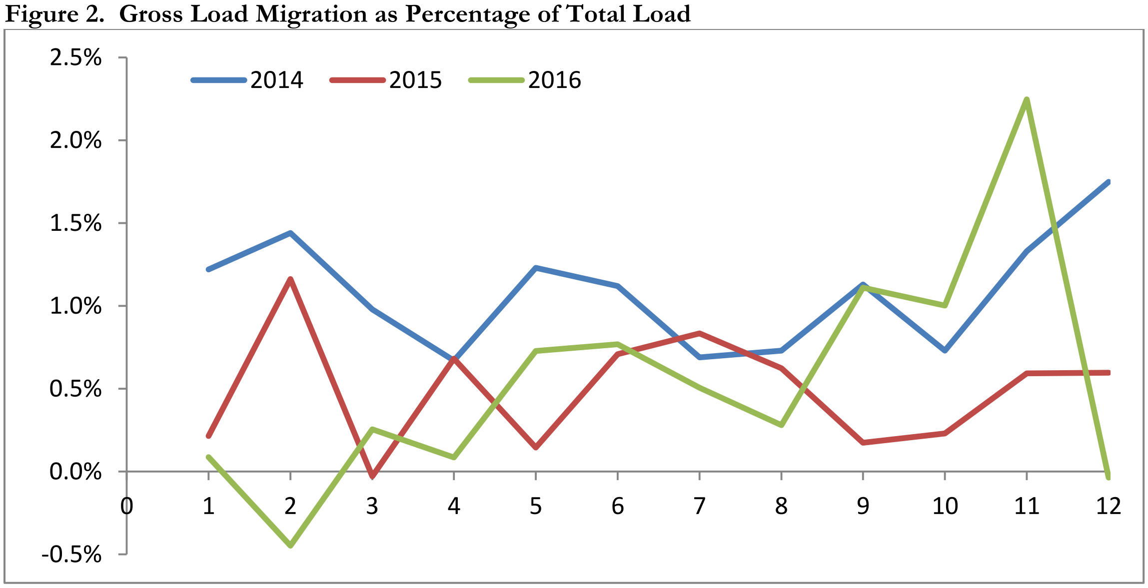
Figure 1 and Figure 2 illustrate the gross monthly load migration between LSEs from 2014 through 2016. Load migration remained relatively low throughout this period with monthly migration remaining below 700 MW and 2.5% of total load.

Figure 1. Gross Load Migration Adjustments per Month (MW), 2014-2016



Source: Monthly forecast adjustments submitted by LSEs, 2014-2016.

Figure 2. Gross Load Migration as Percentage of Total Load



Source: Monthly forecast adjustments submitted by LSEs, 2014-2016.

3.2 System RA Requirements for CPUC-Jurisdictional LSEs

CPUC-jurisdictional LSEs met their individual and collective system RA requirements for every month of 2016. The total MW of RA resources procured exceeded the total system RAR by 0.4% to 5.4%, depending on the month. Table 4 shows the total CPUC-jurisdictional RA procurement for each month of 2016, 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 are also reported with the 15% PRM applied.

The data represented in Table 4 reflect the committed RA procurement for 2016 for all CPUC jurisdictional LSEs by contract type, and compares this procurement to the procurement obligation. In 2016, 86 to 91% of all committed RA capacity, including CAM, was procured from unit-specific physical resources within the CAISO control area, 5 to 9 percent of capacity was from imports, and 3 to 5 percent was from DR resources. CAM and RMR resources consisted of 12 to 18 percent of total RA capacity procured.

Table 4. 2016 RA Filing Summary – CPUC-Jurisdictional Entities (MW)

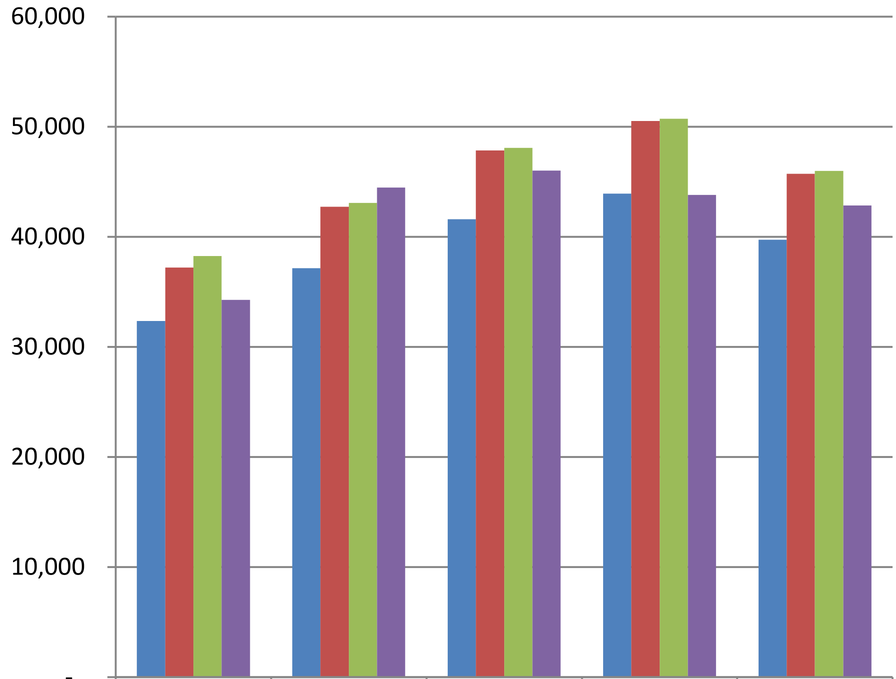
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
RAR without DR,CAM, & RMR	32,823	31,610	31,650	32,790	37,204	42,721	47,830	50,510	45,701	37,985	33,323	33,870
Phys. Res.	30,068	29,140	28,952	30,769	34,191	38,294	41,559	43,651	39,770	33,652	31,303	31,496
Imports	1,964	2,410	2,426	1,734	2,118	2,704	4,304	4,770	3,992	2,594	2,487	2,008
DR plus 15% PRM	1,136	1,118	1,193	1,438	1,788	1,915	2,054	2,138	2,068	1,849	1,184	1,081
CAM & RMR	5,854	5,876	5,813	6,087	6,050	6,096	6,109	6,116	6,126	6,106	6,184	6,173
Total	33,319	32,820	32,722	34,093	38,249	43,064	48,069	50,710	45,981	38,246	35,126	34,737
Total/RAR	**101.5%**	**103.8%**	**103.4%**	**104.0%**	**102.8%**	**100.8%**	**100.5%**	**100.4%**	**100.6%**	**100.7%**	**105.4%**	**102.6%**

Source: Aggregated LSE Monthly RA Filings.

In 2016, total committed RA resources, including DR and CAM, ranged from 32,722 MW in March to 50,710 MW in August. These resources enabled CPUC jurisdictional LSEs to meet between 100 and 105 percent of total procurement obligations in each summer month. Actual peak demand occurred on July 27, 2016 at 46,008 MW.

Figure 3 reflects 2016 total load forecast, procurement obligation (forecast plus planning reserve margin), and total committed RA for only CPUC-jurisdictional LSEs. These are compared with the 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.

Figure 3 2016 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.)	32,351	37,149	41,592	43,921	39,740
Forward Commitment Obligation	37,204	42,721	47,830	50,510	45,701
Total RA Resources Committed	38,249	43,064	48,069	50,710	45,981
Actual Peak Load (CAISO)	34,250	44,452	46,008	43,798	42,837

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

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 2016.

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 8.62% for August 2016.[21]

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

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 all 12 months of the coming compliance year. Local RA requirements are developed through the CAISO's annual Local Capacity Technical Analysis. The annual study 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.[22] The results of the analysis are adopted in the annual RA decision and allocated to each LSE based on their August load ratio in each TAC area.

All LSEs are required to make a 12 month showing of their local requirement on or around October 31, with their system year-ahead showing.[23] In D.15-06-063, the CPUC adopted the 2016 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 one area known as the "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 2016 are summarized in Table 5. CPUC-jurisdictional LSE procurement exceeded local RA obligations in each of the five local areas by 3 to 33%. Aggregate minimum procurement across all local areas exceeded local RA requirements by 13% in 2016. Local requirements are allocated to LSEs net of RMR, as these resources are used to reduce an 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 2016, CPUC-Jurisdictional LSEs

Local Areas in 2016	Total LCR	CPUC-Jurisdictional Local RAR	Minimum Physical Resources per Month	Local RMR & CAM Credit	Local DR	Minimum Procurement/ Local RAR
LA Basin	8,887	7,998	8,005	2,474	930	112%
Big Creek/Ventura	2,398	1,849	1,890	754	222	114%
San Diego-IV	3,184	3,114	3,163	49	52	103%
Greater Bay Area	4,349	3,541	4,511	1,288	64	133%
Other PG&E Areas	6,523	5,340	5,591	316	184	108%
Totals	**25,341**	**21,842**	**23,160**	**4,881**	**1,452**	**113%**

[22] Local Capacity Requirement (LCR) studies and materials for 2016 and previous years are posted at http://www.caiso.com/informed/Pages/StakeholderProcesses/LocalCapacityRequirementsProcess.aspx .
[23] 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 worked but proved cumbersome, and in D.10-12-038 the process was modified for the 2011 compliance year and beyond. The new local true-up process consists 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.

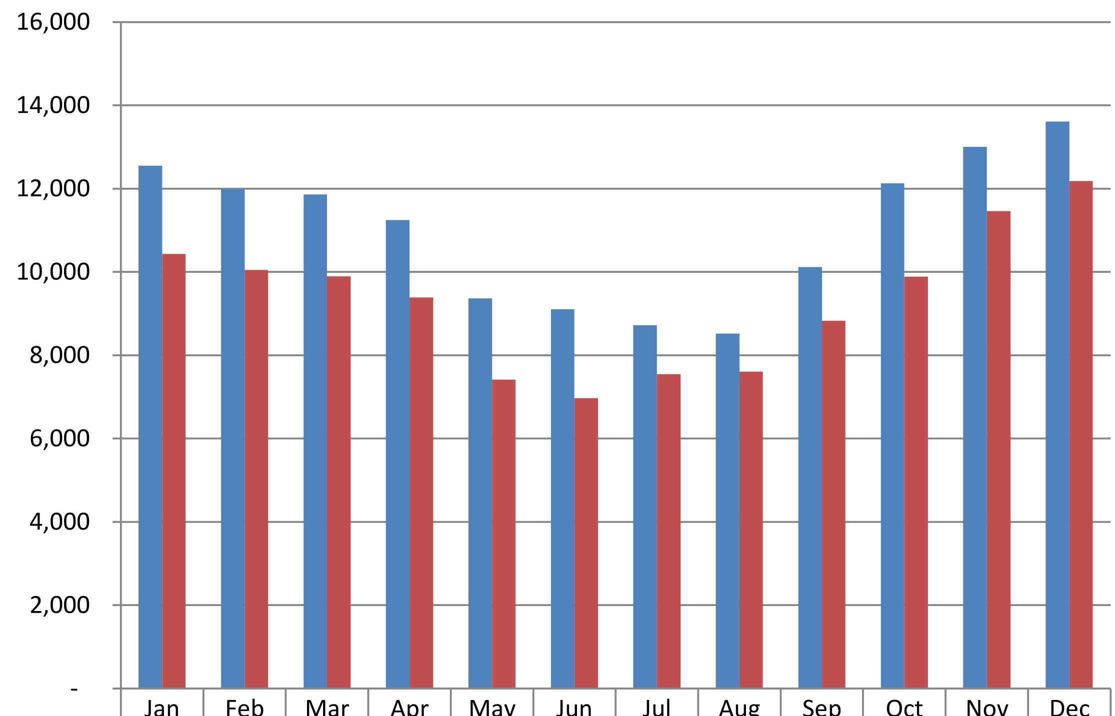
In the allocation cycle for 2016, LSEs submitted revised August forecasts to the CEC on March 16, 2016 along with their June to December load forecasts. After reviewing these values, the CEC revised the August load shares. Energy Division used the revised load shares to recalculate individual LSE local 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 13, 2016, 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.[24] 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 for CPUC-jurisdictional LSEs each month for 2015 and 2016, as well as flexible capacity procured by CPUC-jurisdictional LSEs for 2015 and 2016.

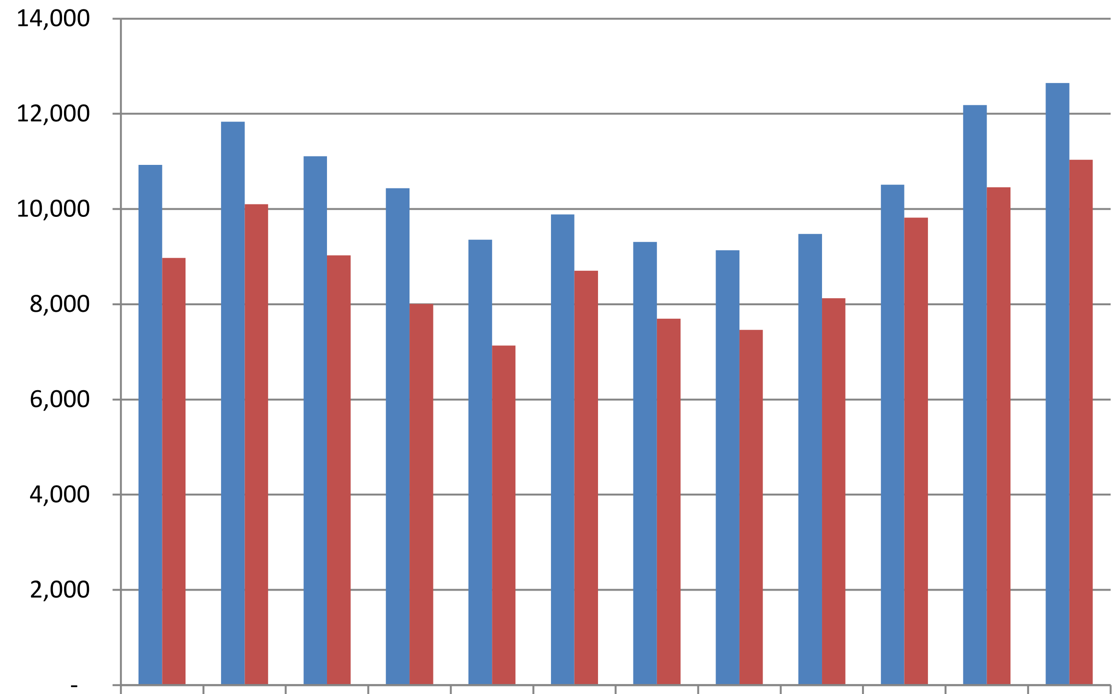
Figure 4. Flexible RA Procurement in 2015 and 2016, CPUC-Jurisdictional LSEs



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016 Flexible Capacity on RA Plan	12,548	11,987	11,859	11,241	9,363	9,100	8,722	8,521	10,112	12,124	13,004	13,612
2016 Flexible RA Requirements	10,429	10,050	9,894	9,389	7,417	6,967	7,546	7,606	8,825	9,886	11,462	12,179

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

2016 Resource Adequacy Report



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2015 Flexible Capacity on RA Plan	10,925	11,832	11,111	10,437	9,353	9,883	9,311	9,136	9,478	10,513	12,184	12,647
2015 Flexible RA Requirements	8,972	10,099	9,025	8,005	7,134	8,707	7,694	7,464	8,126	9,818	10,460	11,035

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 the 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 began authorizing IOUs, in the Long Term Procurement Plan (LTPP), to procure new generation resources to meet reliability needs (both system and local) beginning in 2007. Resources procured to meet reliability must go through something known as the Cost Allocation Mechanism (CAM). The CAM mechanism 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 12, 2017, Energy Division issued a data request to all 22 CPUC-jurisdictional LSEs (comprised of three IOUs, 14 ESPs, and 5 CCAs) asking for monthly capacity prices paid by (or to) LSEs for every RA capacity contract covering the 2016-2020 compliance years. The data request was confined to RA-only capacity contracts bought or sold covering the period from January 2016 – December 2020. 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 22 LSEs that were sent the data request, Energy Division received twelve responses (from three IOUs, and five ESPs, and four CCAs), which consisted of a combined 2,241 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 2016 and 2017. This is as expected, since at the time that the data was collected the 2016 RA compliance years had ended, and there had only been a year-ahead showing and a few month ahead showings for 2017 compliance year.

In an attempt to get a better understanding of the magnitude of the data set, we compare the data set to 2016 RA requirements. Keep in mind that the results include both capacity MWs bought and sold, which may result in the double counting of the same MW being used to meet the monthly RA requirement. In 2016, the sum of monthly contracted capacity represents approximately 20% of the 2016 monthly sum of RA requirements net CAM, RMR and DR allocations.[25] The remainder of RA capacity for that year either was not reported because it was not procured via an RA-only capacity contract, or was procured by an LSE that did not respond to the Energy Division's data request. While the data set coverage of 20% of 2016 capacity is far from complete, it nevertheless provides important insights into overall RA pricing in that year. If we use the aggregate 2016 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 2017 the sum of monthly contracts represent about 22%, the 2018 to 2020 data represents about 48%.[26]

Table 6. Capacity Prices by Compliance Year, 2016-2017

	2016 Capacity	2017 Capacity	2018 to 2020 Capacity
Contracted Capacity (MW)	90,341	68,377	145,965
Percentage of total contracted MW in dataset	30%	22%	48%
Weighted Average Price ($/kW-month)	$2.90	$2.96	
Average Price ($/kW-month)	$2.53	$2.57	
Minimum Price ($/kW-month)	$0.27	$0.15	
Maximum Price ($/kW-month)	$26.54	$6.43	
85% of MW at or below ($/kW-month)	$4.21	$4.34	

[25] The 20% is calculated by dividing the sum of contracted capacity in 2016 (90,341 MW) by the sum of all 2016 monthly RA obligations net of CAM, RMR, and DR allocations (456,325 MW).
[26] To protect confidentiality, the price from 2018-2020 can not be published.

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 system RA contracts are differentiated by the unit's location, which is taken from the 2017 Net Qualifying Capacity list.[27] Local RA Capacity areas are described in Section 3.3 of the report.

Table 7 below presents the summary statistics from the data set. All prices are in units of nominal dollars per kW-month. The data set represents 304,684 MW-months of capacity under contract. Of that capacity, 39% is located in the North of Path 26 (NP-26) Zone and 61% is located in the South of Path 26 (SP-26) Zone.[28] The data also show that 87% of the total capacity is located in local areas, with 13% located in the CAISO system area. Of the local RA capacity reported, the majority – 67% – is located in one of the SP-26 local areas; the remaining 33% is located in an NP-26 local area. The CAISO system RA has the opposite breakdown, with 81% of capacity located in the NP-26 Zone and only 19% of System RA capacity located in the SP-26 Zone.[29]

Table 7. Aggregated RA Contract Prices, 2016-2020

	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)	304,684	118,907	185,777	**263,908**	85,801	178,107	**40,776**	33,106	7,670
Percentage of Total Capacity in Data Set	**100%**	39%	61%	**87%**	33%	67%	**13%**	81%	19%
Number of Monthly Values	**2,241**	986	1255	**1,944**	727	1,217	**297**	259	38
Weighted Average Price ($/kW-month)	**$3.10**	$2.32	$3.60	**$3.20**	$2.19	$3.69	**$2.44**	$2.64	$1.57
Average Price ($/kW-month)	**$2.77**	$2.02	$3.35	**$2.91**	$2.06	$3.42	**$1.82**	$1.89	$1.37
Minimum Price ($/kW-month)	**$0.15**	$0.60	$0.15	**$0.27**	$0.63	$0.27	**$0.15**	$0.60	$0.15
Maximum Price ($/kW-month)	**$26.54**	$5.80	$26.54	**$26.54**	$4.81	$26.54	**$5.80**	$5.80	$2.12
85% of MW at or below ($/kW-month)	**$4.19**	$3.00	$4.25	**$4.19**	$3.00	$4.25	**$3.00**	$3.50	$1.89

[27] The 2017 Net Qualifying Capacity list can be found at http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

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

[29] 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.

The weighted average price for all capacity is $3.10/kW-month. This is $0.17 higher than the weighted average price reported in the 2015 RA price analysis. The weighted average price for SP-26 capacity (including local and system RA) is $3.60/kW-month, which is about 55% higher than the NP-26 weighted average price of $2.32/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 $4.25/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 31% higher than the weighted average price of system RA capacity. This is expected, as local RA is a more constrained product. However, the weighted average price of local RA capacity in the NP-26 Zone is less than the weighted average price of system RA capacity in the NP-26 Zone. This suggest that capacity prices north of path 26 are supressed due to the over supply in the northern local areas.

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 87% 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, 2016-2020 Compliance Years

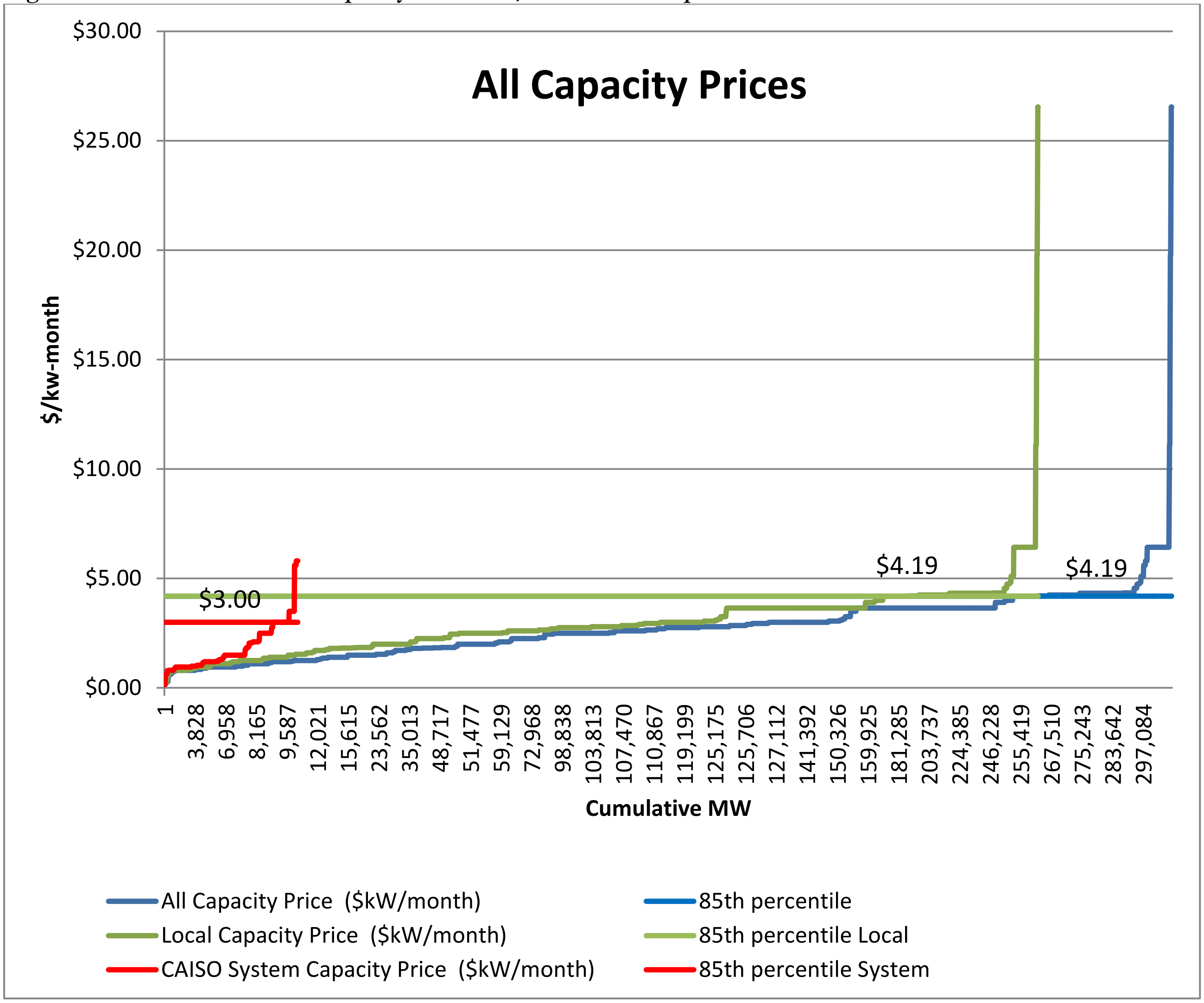


Figure 6. RA Price Curves for Resources North of Path 26, 2016- 2020

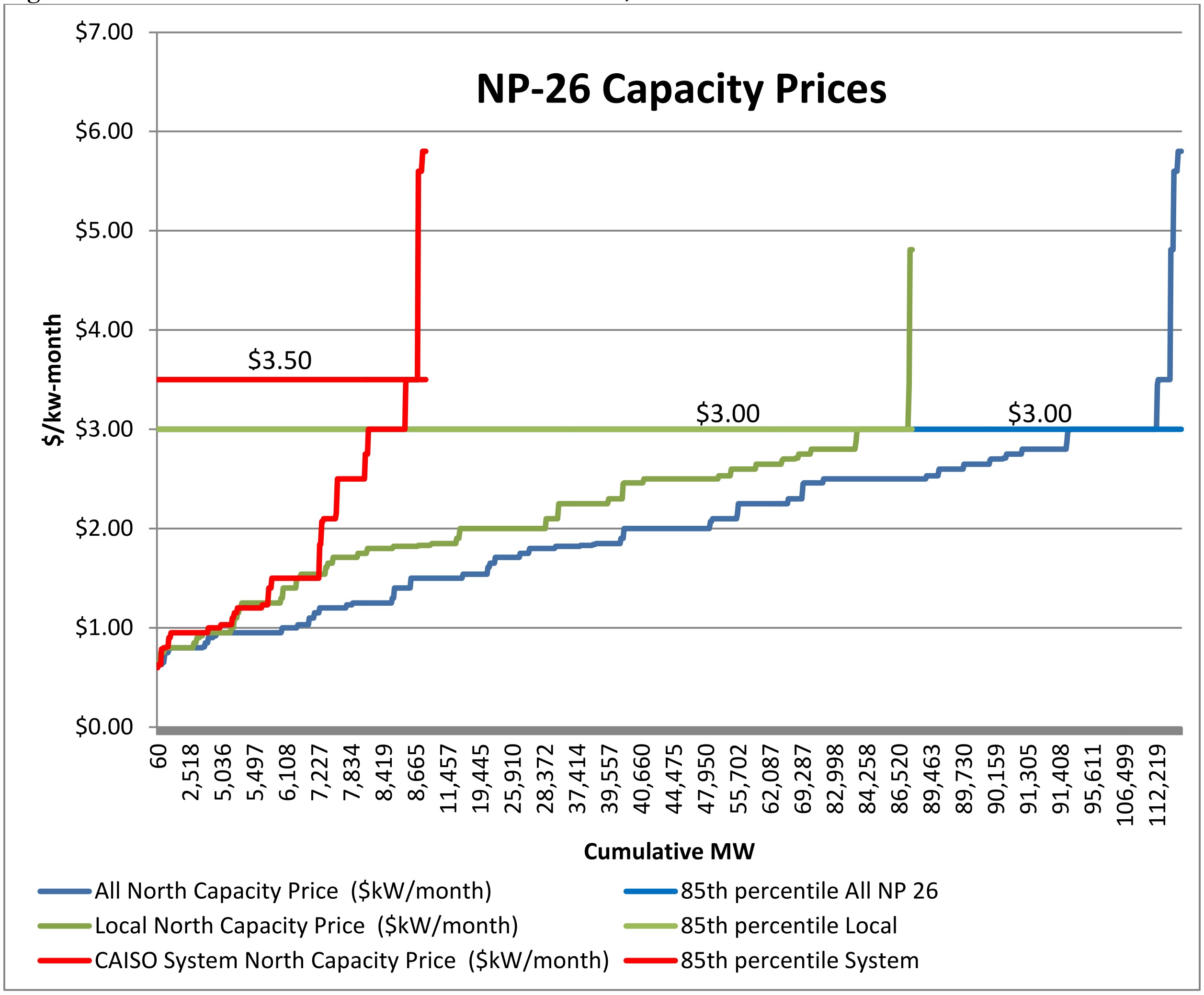


Figure 6 displays price curves for contracted capacity north of Path 26. Like Figure 5, the price curves are differentiated by local and system RA capacity. Similar to the statewide aggregate data, the majority of contracted capacity north of Path-26 were resources located in local areas. The weighted 85th-percentile contract price of system RA Capacity is $0.50/kw-month higher than local RA, indicating that there is generally not a premium placed on Local RA capacity north of Path 26. There are slighted higher price outliers in the system RA capacity curve than there are in the local RA capacity curve.

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 $2.36/kW-month more than for System RA. This is slightly lower than the difference of $2.50/kW-month reported in the 2015 RA report.

Figure 7. RA Price Curves for Resources South of Path 26, 2016-2020

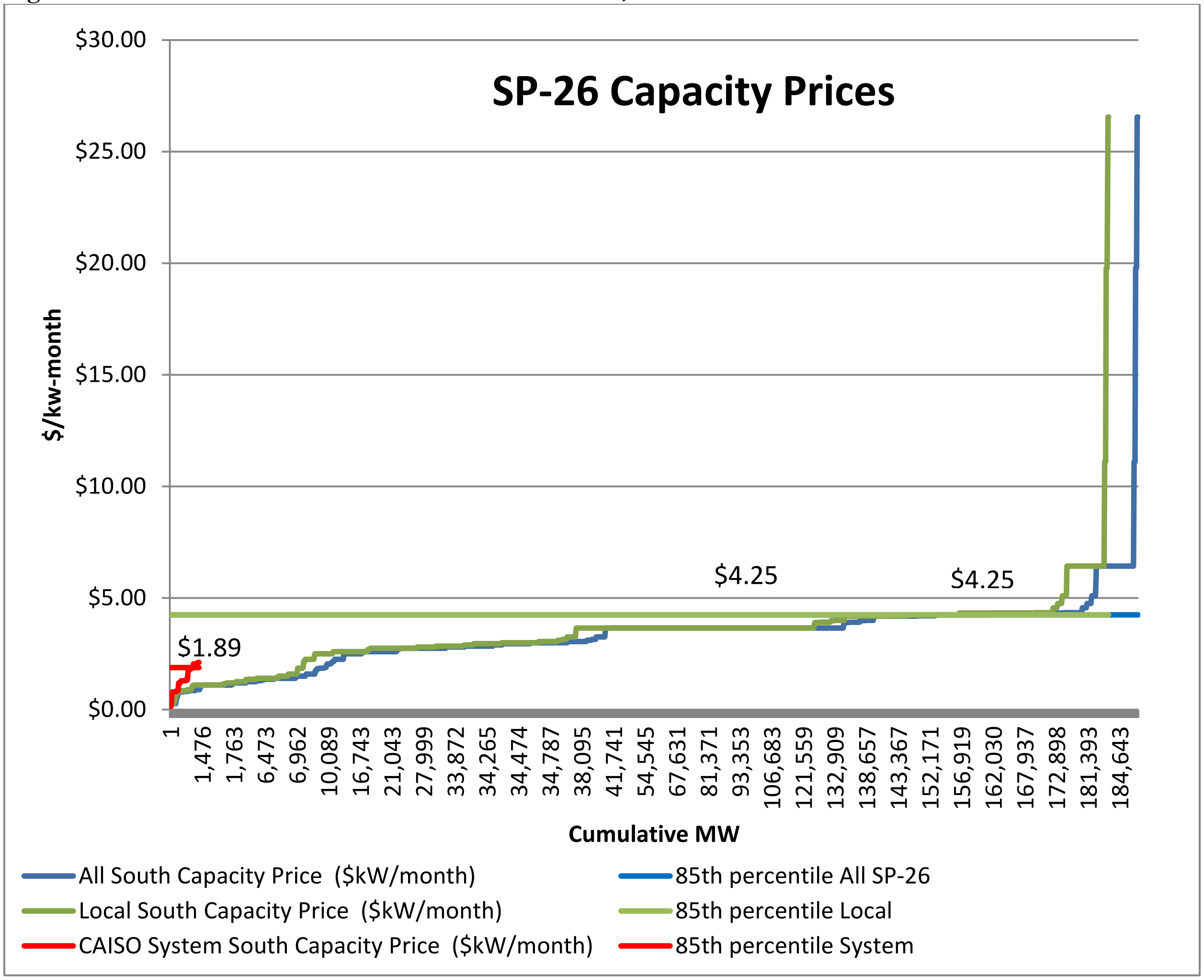


Table 8 reports capacity prices by local capacity area. The San Diego local area has the highest weighted average price and the highest maximum price. San Diego and Big Creek Ventura local area have the highest 85th-percentile price. The 85th-percentile price indicates that 85 percent of the contracted MW in the Big Creek Ventura local area were procured at prices of $4.34/kW-month or below. According to the average weighed price, LA Basin and Big Creek Ventura are similar. According to the 85th percentile price, Big Creek Ventura capacity is more expensive than LA Basin capacity, which is the opposite in the 2015 RA report. Looking at the weighted average price of local areas in the North, the data suggest that Other PG&E area local capacity is less expensive than Bay Area local capacity. However, given the limited data available for Other PG&E local areas (only 2,657 MW of contracted capacity, which is a little more than 3% of the contracted capacity in the Bay Area and only about 0.87% of the total data set), it is not possible to draw any definitive conclusions.

Table 8. Capacity Prices by Local Area, 2016-2020

	LA Basin	Big Creek/Ventura	Bay Area	Other PG&E Area	San Diego-IV	CAISO System
Contracted Capacity (MW)	113,124	36,818	83,144	2,657	28,165	40,776
Percentage of Total Capacity in Data Set	37%	12%	27%	1%	9%	13%
Weighted Average Price ($/kW-month)	$3.62	$3.61	$2.20	$2.09	$4.06	$2.44
Average Price ($/kW-month)	$3.45	$3.03	$2.07	$2.06	$3.73	$1.82
Minimum Price ($/kW-month)	$0.75	$0.85	$0.63	$0.80	$0.27	$0.15
Maximum Price ($/kW-month)	$6.43	$4.34	$4.81	$2.80	$26.54	$5.80
85% of MW at or below ($/kW-month)	$3.65	$4.34	$3.00	$2.50	$4.33	$3.00

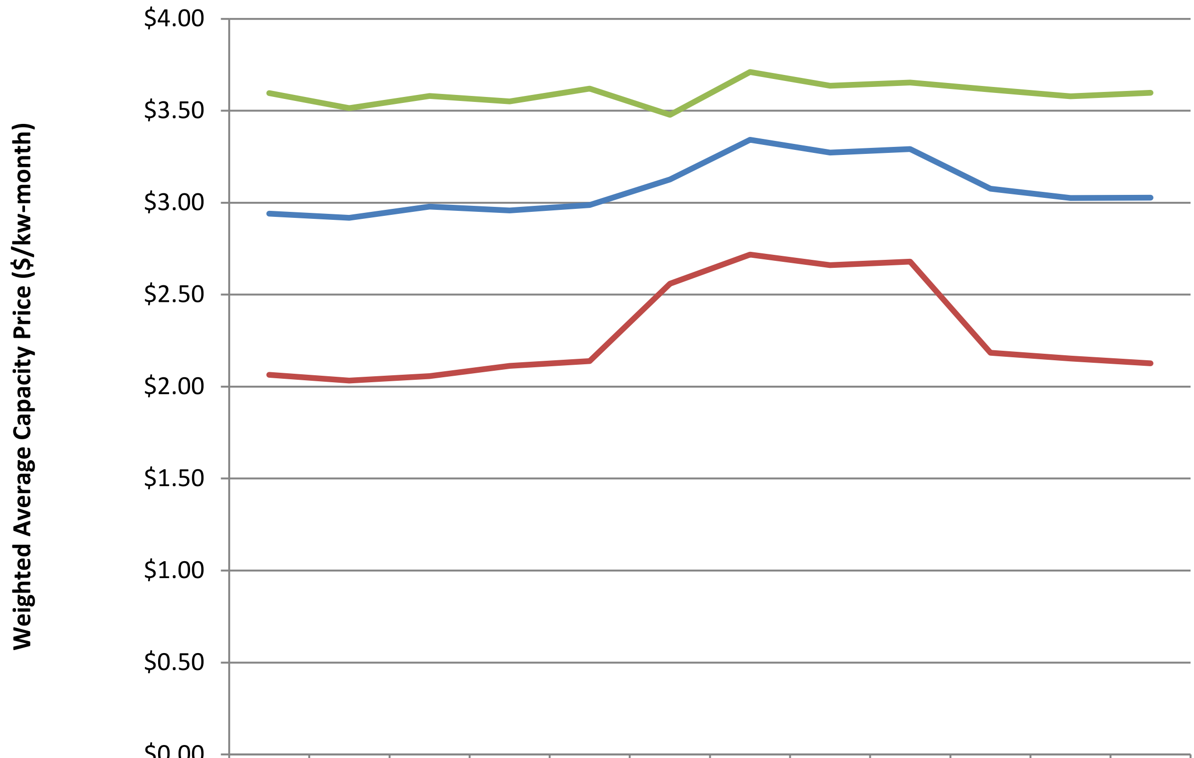
The monthly weighted average capacity prices shown in Table 9 below illustrate that capacity prices are slightly higher from July through September. We would expect to see high prices in the summer given the high demand in the summer months. However, the difference from 2016-2020 is much less drastic than previous years.

Table 9. RA Capacity Prices by Month, 2016-2020

	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	21,734	7%	$2.94	$0.54	$6.43	$4.21
February	20,738	7%	$2.92	$0.15	$6.43	$3.91
March	20,482	7%	$2.98	$0.27	$6.43	$4.21
April	21,141	7%	$2.96	$0.27	$6.43	$4.19
May	22,175	7%	$2.99	$0.80	$6.43	$4.25
June	27,842	9%	$3.13	$0.80	$6.43	$4.19
July	29,733	10%	$3.34	$0.80	$19.77	$4.33
August	33,959	11%	$3.27	$0.80	$26.54	$4.33
September	29,969	10%	$3.29	$0.75	$11.10	$4.19
October	25,757	8%	$3.08	$0.63	$6.43	$3.65
November	25,572	8%	$3.03	$0.63	$6.43	$3.65
December	25,582	8%	$3.03	$0.63	$6.43	$3.65

Figure 8 graphs the weighted average capacity prices by month and zone. Compared to previous years, there is a smaller difference in prices for capacity in the north and south during the summer months. Overall capacity price and SP-26 capacity price tend to have flattened out from January to December, which is different from previous years where capacity prices in the summer are much highter than non-summer months. The slightly higher prices in the south may reflect lower supply levels and more constrained local capacity areas in Southern California. However, this effect is not nearly as pronounced as previous years.

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	$2.94	$2.92	$2.98	$2.96	$2.99	$3.13	$3.34	$3.27	$3.29	$3.08	$3.03	$3.03
NP 26 Prices	$2.06	$2.03	$2.06	$2.11	$2.14	$2.56	$2.72	$2.66	$2.68	$2.18	$2.15	$2.13
SP 26 Prices	$3.60	$3.51	$3.58	$3.55	$3.62	$3.48	$3.71	$3.64	$3.65	$3.62	$3.58	$3.60

Figure 9 graphs the contracted capacity by months and year. As expected, total capacity contracted in the summer is higher in 2016 than 2017. Because there is more capacity contracted in each year for July-September, there is more contracted capacity overall in 2016 than 2017. Note that the data set was collected at the beginning of 2017, which means the 2016 RA compliance years had concluded. [30]

[30] To protect confidentiality, 2018-2020 data can not be published.

Figure 9. Contracted RA Capacity by Month, 2016- 2017

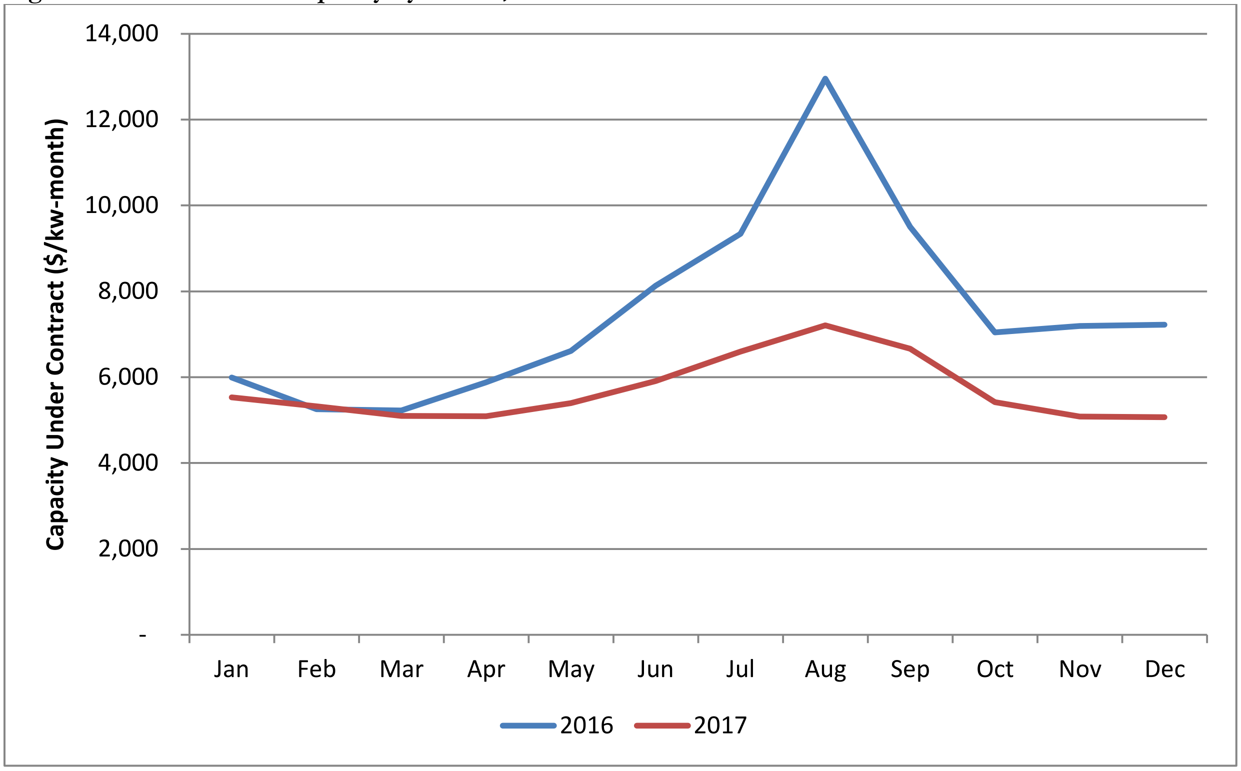


Figure 10. Weighted Average Capacity Prices by Month, 2016-2017

Figure 10 graphs the weighted average capacity prices by month and year. Prices are highest during the summer months for 2016 and 2017. The prices have increased in June- September from 2016 to 2017, which is opposite of what we've seen in past years. [31]

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,[32] 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. [33] 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.

4.3 CAISO Out of Market Procurement – CPM Designations

CAISO implemented the Capacity Procurement Mechanism (CPM) effective April 1, 2011. The purpose of CPM is to enable the CAISO 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;

[31] To protect confidentiality, the prices from 2018-2020 can not be published.
[32] D.06-06-064, Section 3.3.7.1.
[33] 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

- 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.[34]

Eligible capacity is the capacity of resources that is not already under a contract to be a RA resource, is not under an RMR contract, and is 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 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.[35]

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 cost-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.[36] All potential CPM designations, except risk of retirement designations, will be covered through this process.

Table 10 shows CAISO's CPM designation from 2012 to 2016.

Table 10. CAISO CPM Designation from 2012-2016

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

34 CAISO Reliability BPM, version 30, page 147.
https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Reliability%20Requirements
35 CAISO Capacity Procurement Mechanism Overview Presentation, March 3, 2011,
http://www.caiso.com/Documents/CapacityProcurementMechanismOverview.pdf
36 CAISO 2016 Fourth Quarter Market Issues and Performance Report, March, 2017, page 68,
http://www.caiso.com/Documents/2016FourthQuarterReport-MarketIssuesandPerformanceMarch2017.pdf

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
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

As Table 10 shows, there were no CPM designations due to LSEs' capacity deficiencies or capacity at risk of retirement. There were CPM designations due to significant event and exceptional dispatch. Huntington Beach Unit 3 and 4 received CPM designations due to the outage of SONGS in the summer of 2012. In 2016, all the CPM designations issued 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, with the costs and benefits to 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 rights to 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.

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*
AltaGas Battery Storage	4/1/2017	12/30/2026	SCE	20.00

Powin Energy – Milligan ESS 1	7/1/2017	12/31/2026	SCE	2.00
Energy Storage 1	4/1/2017	UOG	SDG&E	30.00
Energy Storage 2	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

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

D.10-12-035[37] 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 have the IOUs 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.[38] 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.[39]

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. Table 12, below, lists the CHP resources whose RA capacity credits were allocated from 2013 to 2016.

Table 12. CHP Resources Allocated for CAM 2013-2016

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
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

37 http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/128624.htm

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

39 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."

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	4/22/2016	4/23/2021	SCE	14.74
SNCLRA_2_UNIT1	1/1/2016	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

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

*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. On about April 1 of each year, the IOUs/DR providers submit the ex-ante load impact values associated with each DR program 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.[40] This was done by adding an additional tab 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 2,362 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.

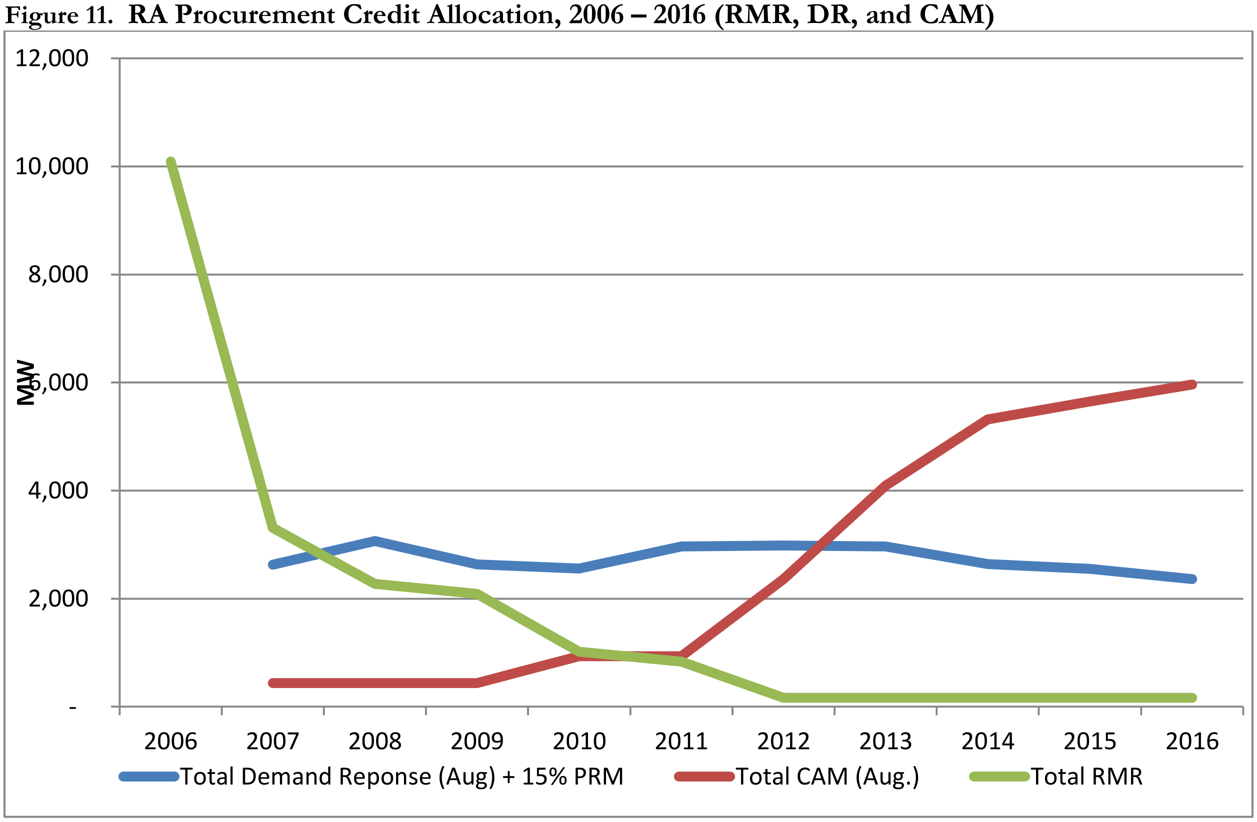
[40] D.12-06-025.

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 and the increase in CAM units. DR RA credits have slightly declined since 2013. The total amount of capacity procured through DR, CAM and RMR for August 2016 was 8,491 MW. This is 17% of the total CPUC-jurisdictional LSE obligation for August 2016 (50,510 MW). In August 2016, total CAM procurement reached 5,964 MW where RMR procurement consisted of only 165 MW (CPUC jurisdictional LSEs were allocated 151.52 MW of the 165 MW in August 2016).

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

		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
DR Procurement	SCE			1,705	1,616	1,613	1,838	2,067	2,195	1,615	1,626	1,519
	PG&E			1018	912	846	888	744	783	933	807	724
	SDG&E			346	104	97	241	177	135	96	121	119
	Total DR (Aug)		**2,628**	**3,069**	**2,633**	**2,556**	**2,967**	**2,987**	**3,114**	**2,644**	**2,554**	**2,362**
CAM Procurement	SCE		436	436	436	936	936	1,529	2,763	3,477	3,583	3,869
	PG&E							703	1,351	1,790	2,020	2044
	SDG&E							130		49	49	52
	Total CAM (Aug)		**436**	**436**	**436**	**936**	**936**	**2,362**	**4,114**	**5,316**	**5,652**	**5,964**
RMR Procurement	SCE	1,390										
	PG&E	6,151	1,348	1,303	1,263	709	527	165	165	165	165	165
	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**

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.[41] The applicable data sets and data conventions are laid out in the adopted QC methodology manual, which is posted on the CPUC website.[42] For dispatchable resources, the QC is based on the most recent Pmax test. The Pmax test is kept in the ISO's master file. For wind, solar, and non-dispatchable hydro 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. The CPUC executes a subpoena for settlement quality meter and bidding data from the ISO and performs QC calculations for non-dispatchable resources annually.

After the QC values are determined, the CAISO conducts a deliverability assessment to produce the 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).[43] 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 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 2016

The addition of new capacity increased significantly in 2016 in comparison to the previous several years with 3,592 MW of new generation coming online and 2,335 MW retiring for a net gain of 1,257 MW.[44] While the majority of new resources were solar PV, the 318 MW Pio Pico gas generator also came online in 2016 as did several storage facilities.

Table 14 lists the new and retiring facilities for 2016. 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 2016, the net dependable capacity of facilities that came online was nearly nearly 1,000 MW greater than the assigned NQC values.

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[41] http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/119856.htm (QC manual adopted as Appendix B).
[42] http://www.cpuc.ca.gov/General.aspx?id=6311
[43] The CAISO's deliverability assessment methodology is available at http://www.caiso.com/23d7/23d7e41c14580.pdf
[44] NQC lists for 2015-2017 are available at:
http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

Table 14. New NQC Resources Online in 2016

Resource ID	Resource Name	Technology	NQC[45]	Net Dependable Capacity
ASTORA_2_SOLAR1	Astoria 1	Solar PV	79.42	100
ASTORA_2_SOLAR2	Astoria 2	Solar PV	60.26	75
BIGSKY_2_SOLAR1	Antelope Big Sky Ranch	Solar PV	16.07	20
BIGSKY_2_SOLAR2	Big Sky Solar 4	Solar PV	32.14	40
BIGSKY_2_SOLAR4	Western Antelope Blue Sky Ranch B	Solar PV	16.07	20
BIGSKY_2_SOLAR5	Big Sky Solar 2	Solar PV	4.02	5
BIGSKY_2_SOLAR6	Solverde 1	Solar PV	68.29	85
BIGSKY_2_SOLAR7	Big Sky Solar 1	Solar PV	40.17	50
BLKCRK_2_SOLAR1	McCoy Station	Solar PV	192.79	250
CALPSS_6_SOLAR1	Calipatria Solar Farm	Solar PV	15.99	19.9
CEDUCR_2_SOLAR1	Ducor Solar 1	Solar PV	0	20
CEDUCR_2_SOLAR2	Ducor Solar 2	Solar PV	0	20
CEDUCR_2_SOLAR3	Ducor Solar 3	Solar PV	0	15
CEDUCR_2_SOLAR4	Ducor Solar 4	Solar PV	0	20
CHINO_2_APEBT1	Pomona Energy Storage	Storage	20	20
COPMT4_2_SOLAR4	Copper Mountain Solar 4	Solar PV	73.92	92
CRWCKS_1_SOLAR1	Crow Creek Solar 1	Solar PV	0	20
DELSUR_6_CREST	SCE Del Sur Aggregate	Solar PV	0	10.5
DRACKR_2_SOLAR1	Dracker Solar Unit 1	Solar PV	88.38	110
DRACKR_2_SOLAR2	Dracker Solar Unit 2	Solar PV	100.43	125
DSRTSL_2_SOLAR1	Desert Stateline	Solar PV	241.03	296.19
ETIWND_2_SOLAR1	Dedeaux Ontario	Solar PV	0	1
ETIWND_2_SOLAR2	Rochester	Solar PV	0	1
ETIWND_2_SOLAR5	Dulles	Solar PV	0	2
EXCLSG_1_SOLAR	Excelsior Solar	Solar PV	41.54	60
FRESHW_1_SOLAR1	Freshwater Solar	Solar PV	0	20
GARLND_2_GASLR	Garland B	Solar PV	144.62	180
GARLND_2_GASLRA	Garland A	Solar PV	16.07	20
GLNARM_2_UNIT 5	Glenarm Turbine 5	CCGT	65	68
HENRTA_6_SOLAR1	Lemoore 1	Solar PV	0	1.5
HENRTA_6_SOLAR2	Westside Solar Power PV1	Solar PV	0	2
HENRTS_1_SOLAR	Henrietta Solar Project	Solar PV	80.34	100
IVWEST_2_SOLAR1	Imperial Valley West (Q608)	Solar PV	120.52	150
KNGBRD_2_SOLAR1	Kingbird Solar A	Solar PV	16.07	20
KNGBRD_2_SOLAR2	Kingbird Solar B	Solar PV	16.07	20

[45] 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.

LILIAC_6_SOLAR	Mesa Crest	Solar PV	2.41	3
LITLRK_6_SOLAR2	Palmdale 18	Solar PV	1.61	2
LITLRK_6_SOLAR4	Little Rock Pham	Solar PV	2.41	3
MIRLOM_2_MLBBTA	Mira Loma BESS A	Storage	0	10
MIRLOM_2_MLBBTB	Mira Loma BESS B	Storage	0	10
MOJAVW_2_SOLAR	Mojave West	Solar PV	16.07	20
MONLTH_6_BATTRY	Tehachapi Wind Energy Storage Project	Storage	0	8
MSOLAR_2_SOLAR2	Mesquite Solar 2	Solar PV	80.99	100.81
MSOLAR_2_SOLAR3	Mesquite Solar 3	Solar PV	122.12	152
MSTANG_2_SOLAR	Mustang	Solar PV	24.1	30
MSTANG_2_SOLAR3	Mustang 3	Solar PV	32.14	40
MSTANG_2_SOLAR4	Mustang 4	Solar PV	24.1	30
OASIS_6_CREST	SCE Oasis Aggregate Solar Resources	Solar PV	0	13.5
OASIS_6_SOLAR2	Oasis Solar	Solar PV	16.07	20
ORLND_6_SOLAR1	Enerparc California 2	Solar PV	1.21	1.5
PBLOSM_2_SOLAR	Pearblossom Solar	Solar PV	7.63	9.5
PEABDY_2_LNDFL1	Potrero Hills Energy Producers	Biogas	6.48	8
PIOPIC_2_CTG1	Pio Pico Unit 1	Simple Cycle Gas	106	106
PIOPIC_2_CTG2	Pio Pico Unit 2	Simple Cycle Gas	106	106
PIOPIC_2_CTG3	Pio Pico Unit 3	Simple Cycle Gas	106	106
PLAINV_6_DSOLAR	Western Antelope Dry Ranch	Solar PV	8.03	10
PLAINV_6_NLRSR1	North Lancaster Ranch	Solar PV	16.07	20
PLAINV_6_SOLARC	Central Antelope Dry Ranch C	Solar PV	0	20
PMPJCK_1_RB2SLR	Rio Bravo Solar 2	Solar PV	13.32	19.5
PMPJCK_1_SOLAR2	Rio Bravo Solar 1	Solar PV	15.67	19.5
PRIMM_2_SOLAR1	Silver State South Solar Project	Solar PV	200.86	250
RDWAY_1_CREST	SCE Roadway Aggregate Solar Resources	Solar PV	0	6.5
RECTOR_2_CREST	Rector Aggregate Solar Resources	Solar PV	0	14
RTEDDY_2_SOLAR1	Rosamond West Solar 1	Solar PV	43.39	54
RTEDDY_2_SOLAR2	Rosamond West Solar 2	Solar PV	43.39	55
SANTGO_2_LNDFL1	Bowerman Power	BIOGAS	15.88	19.6
SHUTLE_6_CREST	SCE Shutle Aggregate Solar Resources	Solar PV	0	4
SWIFT_1_NAS	Yerba Buena NaS	Storage	0	4
TORTLA_1_SOLAR	Longboat Solar	Solar PV	0	20
TRNQLT_2_SOLAR	Tranquillity	Solar PV	160.69	200
TX-ELK_6_SOLAR1	Castor Solar Project	Solar PV	0	1.5
VESTAL_2_SOLAR1	Nicolis	Solar PV	13.85	20
VESTAL_2_SOLAR2	Tropico	Solar PV	9.69	14
VLCNTR_6_VCSLR	Cole Grade	Solar PV	1.87	2.33

Total	2747.26	3592.33

Table 15. Resources that Retired in 2016

Resource ID	Resource Name	Technology	NQC
ALTMID_2_UNIT 1	Altamont Midway Ltd.	Wind	0.49
BORDEN_2_QF	Small QF Aggregation - Madera	Hydro	0.78
CARDCG_1_UNITS	Cardinal Cogen	Cogeneration	16.11
COLPIN_6_COLLNS	Collins Pine	Biomass	3.06
CURIS_1_QF	Small QF Aggregation - Merced	Hydro	0.33
CWATER_7_UNIT 1	Coolwater Gen Sta. Unit 1	Thermal	63
CWATER_7_UNIT 2	Coolwater Gen Sta. Unit 2	Thermal	81.5
EGATE_7_NOCITY	North City Unit (Eastgate)	Biomass	0.24
ELSEGN_7_UNIT 4	El Segundo Gen Sta. Unit 4	Thermal	335
FLOWD1_6_ALTPP1	Altamont Power Llc (Partners 1)	Wind	0
GALE_1_SEGS1	Sunray Energy, Inc. - SEGS 1	Solar	4.25
HIWAY_7_ACANYN	Gas Recovery(America Canyon)	Biomass	0.18
JESSUP_1_HUDSON	Kiara Anderson	Biomass	3.65
JOHANN_6_QFA1	Johanna QF	Various	0
JVENTR_2_QFUNTS	Tres Vaqueros Wind QF Units	Wind	0.07
KERKH1_7_UNIT 2	Kerkhoff Ph 1 Unit #2	Hydro	0
LAFRES_6_QF	La Fresa QFs	Various	0
LASSEN_6_AGV1	Agv 1	Geothermal	0.95
LEWSTN_7_WEBRFL	Pan Pacific (Weber Flat)	Hydro	0
LFC 51_2_UNIT 1	Patterson Pass Wind Farm LLC	Wind	2.02
LGHTHP_6_QF	Lighthipe QFs	Various	0.3
LNCSTR_6_SOLAR	Sierra Sun Tower, LLC	Solar	7.02
MIDWAY_1_QF	Small QF Aggregation - Bakersfield	Biomass	0.01
MILBRA_1_QF	Small QF Aggregation - Daily City	Cogeneration	0
MTNLAS_6_UNIT	Ogden Power Pacific, Inc.(Mt Lassen)	Biomass	0
OILDAL_1_UNIT 1	Oildale Energy	Cogeneration	38.67
PACORO_6_UNIT	Ogden Power Pacific, Inc. (Oroville)	Biomass	5.17
PITTSP_7_UNIT 5	Pittsburg Unit 5	Thermal	312
PITTSP_7_UNIT 6	Pittsburg Unit 6	Thermal	317
PITTSP_7_UNIT 7	Pittsburg Unit 7	Thermal	530
SANJOA_1_UNIT 1	San Joaquin Cogen	Cogeneration	9.7
SANTGO_6_COYOTE	Gas Recovery Sys. (Coyote Canyon)	Biomass	5.63
SEAWST_6_LAPOS	Sea West Wind QF Aggregation	Wind	0.14
SEGS_1_SEGS2	Sunray Energy, Inc. - SEGS 2	Solar	18.02
SMARQF_1_UNIT 1	Santa Maria Cogen	Cogeneration	0
SUTTER_2_PL1X3	Sutter Power Plant Aggregate	Thermal	500

TEMBLR_7_WELLPT	Nuevo Energy Company (Welport)	Cogeneration	0.18
TKOPWR_2_UNIT	TKO Power	Hydro	0
ULTOGL_1_POSO	Rio Bravo Poso	Cogeneration	28.14
USWND1_2_UNITS	US Wind Power #1(Walker)	Wind	3.89
USWND2_1_UNITS	US Wind Power #2(Patterson)	Wind	12.34
USWPFK_6_FRICK	Green Ridge Power LLC (Frick)	Wind	1.56
VACADX_1_QF	Small QF Aggregation - Vacaville	Wind	0
VESTAL_6_ULTRGN	Rio Bravo Jasmin	Cogeneration	27.87
VESTAL_6_WDFIRE	Sierra Power Corporation	Biomass	5.63
VICTOR_1_QF	Victor QFs	Various	0
WLLWCR_6_CEDRFL	Cedar Flat Hydro QF Aggregation	Hydro	0
		Total	**2334.90**

Source: 2016-2017 NQC lists posted to the CAISO website[46]

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.[47]

5.2 Aggregate NQC Values 2012 through 2017

Table 16 shows aggregate NQC values from the CAISO NQC lists for 2012 through 2017.[48] After several years of minimal change in total NQC, available capacity on the 2017 NQC list increased substantially. The total 2017 NQC (as reported on the CAISO 2016 NQC list) increased by 2,698 MW from the 2016 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 2015 and 2016. For resources whose NQC is based on performance, such as wind and solar resources, each year new data replaces a portion of the old data, causing some year-to-year variation. 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 only partial capacity.

Table 16. Final NQC Values for 2012 – 2017

Year	Total NQC (MW)	Total Number of Scheduling Resource IDs	Net NQC Change (MW)	Net Gain in CAISO IDs on List
2012	50,442	657		
2013	53,336	733	2,894	76
2014	53,112	765	-224	32
2015	52,996	802	-116	37

[46] http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx and http://www.caiso.com/planning/Pages/ReliabilityRequirements/ReliabilityRequirementsArchive.aspx
[47] http://www.energy.ca.gov/sitingcases/all_projects.html
[48] 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.

2016	53,173	972	177	170
2017	55,871	1,097	2,698	125
2012-17			**5,429**	**440**

Source: NQC lists from 2012 through 2017.

6 Compliance with RAR

CPUC staff continued the implementation of the RA program during 2016 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 July 2015 to discuss general compliance rules as well as to highlight changes in procedures and filing rules new to the 2016 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 2016 filing guide and templates were made available to LSEs in August 2015. Changes were made to implement the new RA rules adopted in D.15-06-063, particularly RA program refinements. 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 to date 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 2016, 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 complete backstop procurement if necessary 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., it did not 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. Although the CAISO has not yet needed to engage in backstop procurement for CPUC-jurisdictional LSE procurement deficiencies, this could occur if compliance is not strictly enforced.

6.4 Enforcement Actions in the 2006 through 2016 Compliance Years

Pursuant to Commission Resolution E-4195[49] 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 2016, the Commission issued 41 citations for violations and initiated 4 enforcement cases, citing a total penalty of $180,100 and collecting $175,100 from citations and $847,500 from enforcement cases. In 2016, the Commission issued three citations and took no enforcement action, ultimately citing a total penalty of $13,500 and collecting $8,500 from LSEs.

[49] 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
Total	**41**		**$180,100**	**4**		**$847,500**

Appendix

List of CPUC Jurisdictional LSEs 2016

1. Pacific Gas & Electric
2. Southern California Edison
3. San Diego Gas & Electric
4. 3 Phases Renewables Inc.
5. Commerce Energy 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. Gexa Energy California, LLC
12. Agera Energy LLC
13. Liberty Power Holdings, LLC
14. Marin Clean Energy
15. Noble Americas Energy Solutions, LLC
16. Pilot Power Group, Inc.
17. Shell Energy North America
18. Sonoma Clean Power Authority
19. Tiger Natural Gas, Inc.
20. The Regents of the University of California
21. Lancaster Choice Energy
22. CleanPowerSF
23. Peninsula Clean Energy Authority