The 2015 Resource Adequacy Report

ENERGY DIVISION

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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

2015 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 2015 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 2015, 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 2015, the RA program successfully provided sufficient resources to meet peak load. The 2015 peak demand (for CPUC jurisdictional LSEs) was forecasted to occur in August 2015 at 45,747 MW.[2] The forward procurement obligation/RA obligation to meet peak demand in August totaled 52,609 MW[3] and LSEs collectively procured 52,743 MW[4] to meet expected system needs (which includes 15% reserve margin). Actual peak load for 2015 (for CPUC and non-CPUC jurisdictional LSEs) occurred on September 10, 2015 at 47,252 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 OASIS system. CAISO reported system peak at 47,358 MW. See http://www.caiso.com/Pages/TodaysOutlook.aspx

CPUC jurisdictional LSEs fulfilled their local RA obligations during the 2015 compliance year. 2015 local RA procurement obligations for CPUC-jurisdictional LSEs totaled 22,809 MW. These obligations were met with a monthly minimum of 23,963 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 2015, the CEC made negative plausibility adjustments for all months of the year. The monthly plausibility adjustments as a percentage of the month's aggregated year-ahead forecast ranged from -1.28% to -0.02%.[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 2015, CAM, RMR and DR procurement comprised 15.5% 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 seen a decline since 2013.[9]

In early 2016, 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 2015 – 2019 compliance years. A total of 2,475 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 $2.85 kW-month.[10] The weighted average capacity price for capacity South of Path 26 is about 40% 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 2015, 1,005 MW of new generation came online. These new generation resources were all renewable generators with the vast majority being solar Photovoltaic (PV).[13] In addition, 530 MW of generation retired in 2015[14] resulting in an incremental increase of 475 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 six citations for violations related to compliance year 2015 and collected $33,000 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 2015

Decisions (D.)14-06-050 adopted several new rules for the 2015 compliance year, including the following:

- D.14-06-050 adopted an Interim Flexible Capacity Framework for 2015 to 2017 as an additional component of Resource Adequacy (RA) requirements. Each Load Serving Entity is required to make a year-ahead and month-ahead showing of flexible capacity for each month of the compliance year. In this showing, each LSE shall report all of its committed flexible resources to meet the LSE's flexible capacity procurement requirement for 2015.

- Energy Division will perform one incremental local RA allocation, to occur in May and adjust local RA obligations for the July compliance month through the end of the compliance year, starting with 2015 RA compliance. Beginning with the January 2015 RA compliance month, Energy Division shall reallocate Cost Allocation Mechanism (CAM) and Reliability Must Run (RMR) obligations quarterly, to be sent to LSEs 45 days before the RA filing is due.

- The flexible benefits of CAM resources and combined heat and power (CHP) resources that are contractually able to provide committed flexible capacity shall be allocated among benefiting Electric Service Providers.

- Qualifying Capacity and Effective Flexible Capacity for Energy Storage and Supply-Side Demand Response Resources is modified for the RA compliance years 2015 through 2017 as set forth in Appendix B of the Decision.

- Additional available Path-26 capacity created by the netting of existing contracts will be allocated to LSEs based on the LSE's netting participation-ratio share, and shall no longer be based on LSEs' load-ratio.

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 2015 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 2015 revised annual forecasts were due on August 19, 2014. 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 2015 process:

LSEs file historical load information	**March 20, 2014**
LSEs file 2015 year-ahead load forecast	**April 25, 2014**
LSEs receive 2015 year-ahead RA obligations	**July 31, 2014**
Final date to file revised forecasts for 2015	**August 19, 2014**
LSEs receive revised 2015 RA obligations	**September 18, 2014**

For 2015, CPUC staff sent initial allocations to LSEs on August 4 and final allocations to LSEs on September 23, 2014. 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 2015 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 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 2015 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 which calculates each LSE's expected contribution towards coincident service area peak. The forecast for CPUC-jurisdictional LSEs showed an expected peak in August 2015 of 45,462 MW, which represents a 2.3% increase from the peak forecast of 44,457 MW in 2014.[20]

Table 1. 2015 Aggregated Load Forecast Data (MW) - Results of Energy Commission Review and Adjustment to the 2015 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)	29,988	29,008	28,872	30,569	33,682	39,082	44,330	46,923	42,104	34,827	30,698	31,466
CEC Adjustment for Plausibility/ Migrating Load	(218)	(355)	(51)	(126)	(7)	(298)	(205)	(481)	(311)	(307)	(260)	(199)
EE/DG Adjustment	(99)	(101)	(102)	(157)	(205)	(214)	(241)	(234)	(243)	(204)	(118)	(110)
Pro Rata Adjustment to CEC Forecast	0	0	0	0	9	9	14	7	16	11	0	0
Non-Coincident Peak Demand	**29,670**	**28,552**	**28,718**	**30,286**	**33,479**	**38,579**	**43,898**	**46,214**	**41,565**	**34,327**	**30,319**	**31,156**
Coincidence Adjustment	(885)	(751)	(419)	(424)	(728)	(893)	(1,603)	(752)	(1,226)	(977)	(602)	(530)
Final Load Forecast Used for Compliance	**28,785**	**27,801**	**28,299**	**29,861**	**32,751**	**37,686**	**42,295**	**45,462**	**40,339**	**33,350**	**29,718**	**30,626**

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 2010 through 2015 compliance years and reports the monthly plausibility adjustments to the monthly year-ahead forecast as a percentage for 2015.

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

[20] The 2013-14 RA report can be found at: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6325.

In 2015, the CEC's plausibility adjustments reduced total load for all months. In 2015, the CEC found that four of 17 ESPs and all of the three IOUs required plausibility adjustments in at least one month, an increase over 2014 when only one of fifteen ESPs and one of three IOUs required an adjustment. The 2015 monthly plausibility adjustments as a percentage of that month's aggregated year-ahead forecast ranged from -1.28% to -0.02%. 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, 2010-2015 (MW)

Compliance Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	50	48	19	65	21	22	225	(44)	352	155	17	15
2011	0	28	38	39	161	210	1381	115	1256	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)
2015 Plausibility Adjustment/ Load	-0.76%	-1.28%	-0.18%	-0.42%	-0.02%	-0.79%	-0.48%	-1.06%	-0.77%	-0.92%	-0.88%	-0.65%

Source: Aggregated year-ahead CEC load forecasts, 2010-2015.

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 2015. 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 1.16% for February 2015. On a megawatt basis, the net monthly load migration adjustments ranged from -8 to 356 MW in 2015.

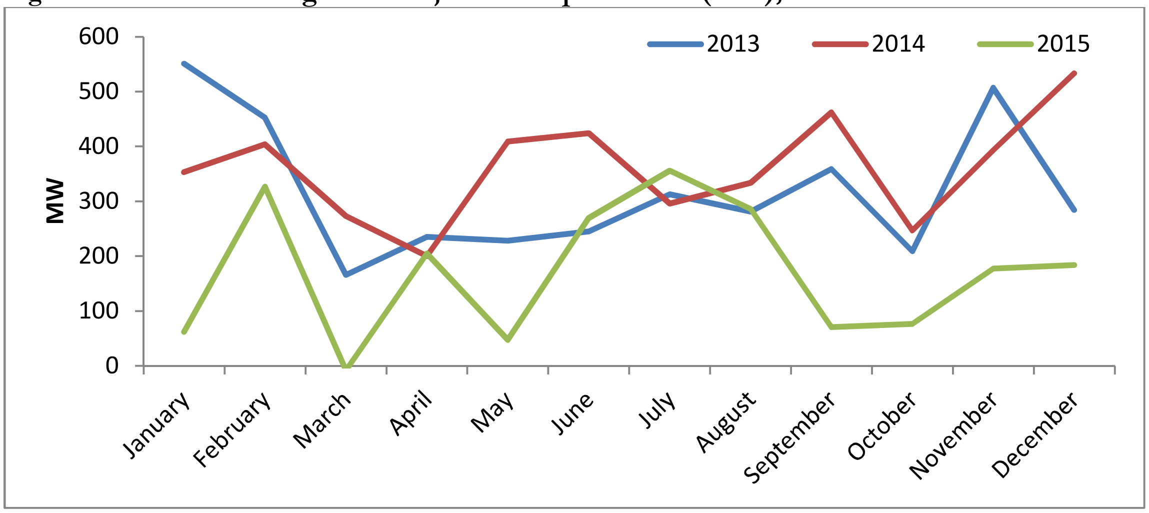
Table 3. Summary of Load Migration Adjustments in 2015 (MW)

Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Total Forecasts , July 2014	28,785	27,801	28,299	29,861	32,751	37,686	42,295	45,462	40,339	33,350	29,718	30,626
Monthly Adjustments, 2015	62	327	-8	205	48	269	356	286	71	77	177	184
Final Forecasts in Monthly RA Filings	28,847	28,128	28,291	30,066	32,799	37,955	42,652	45,748	40,409	33,427	29,895	30,810
Monthly Adjustments/ Final Load Forecast	0.22%	1.16%	-0.03%	0.68%	0.15%	0.71%	0.84%	0.62%	0.17%	0.23%	0.59%	0.60%

Source: Aggregated load forecast adjustments submitted to the CEC and CPUC through 2015.

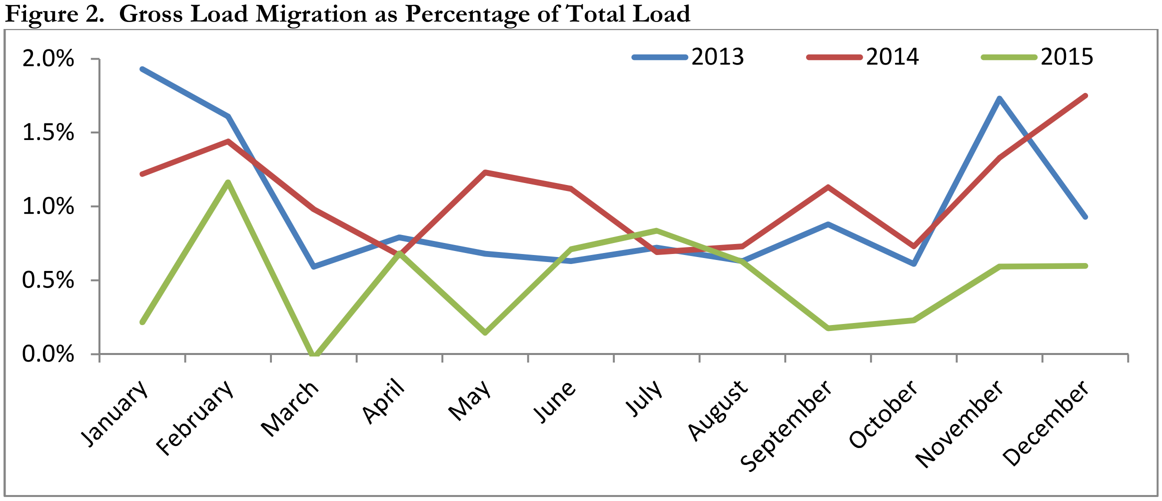
Figure 1 and Figure 2 illustrate the gross monthly load migration between LSEs from 2013 through 2015. Load migration remained relatively low throughout this period with monthly migration remaining below 600 MW and two percent of total load.

Figure 1. Gross Load Migration Adjustments per Month (MW), 2013-2015



Source: Monthly forecast adjustments submitted by LSEs, 2013-2015.

Figure 2. Gross Load Migration as Percentage of Total Load



Source: Monthly forecast adjustments submitted by LSEs, 2013-2015.

3.2 System RA Requirements for CPUC-Jurisdictional LSEs

CPUC-jurisdictional LSEs satisfied their individual and collective system Resource Adequacy (RA) requirements for every month of 2015. The total MW of RA resources procured exceeded the total System RAR by 0.3% to 3.8%, depending on the month. Table 4 shows the total CPUC-jurisdictional RA procurement for each month of 2015, 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 load forecast and IOUs receive an increase in load 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 broken out and are counted once. 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 2015 for all CPUC jurisdictional LSEs by contract type, and compares this procurement to the procurement obligation. In 2015, 87 to 90% of all committed RA capacity, including CAM, was procured from unit-specific physical resources within the CAISO control area, 5 to 8 percent of capacity was from imports, and 3 to 5 percent was from DR resources. CAM and RMR resources consisted of 11 to 17 percent of total RA capacity procured.

Table 4. 2015 RA Filing Summary – CPUC-Jurisdictional Entities (MW)

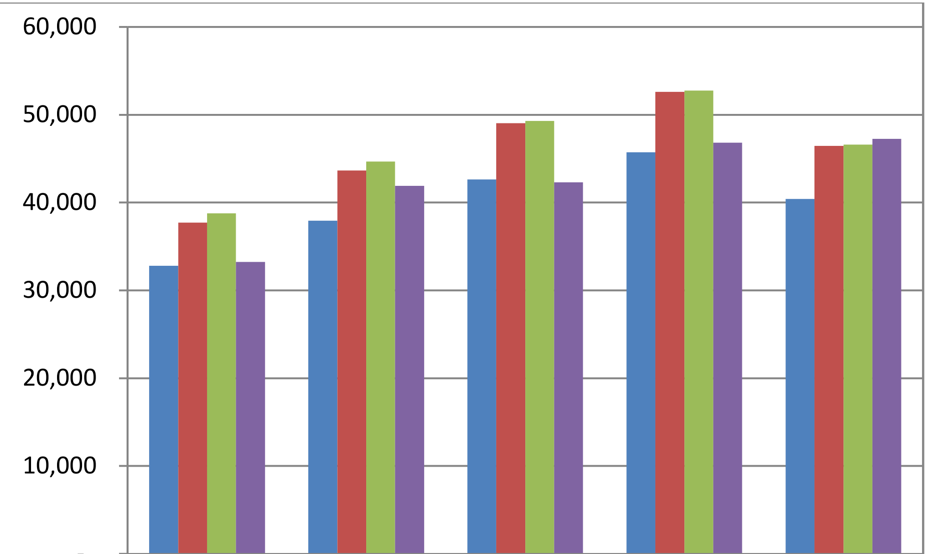
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
RAR without DR,CAM, & RMR	33,174	32,347	32,535	34,576	37,718	43,648	49,048	52,609	46,470	38,366	34,288	35,339
Phys. Res.	30,591	29,928	30,475	32,144	34,658	39,410	44,130	45,837	40,828	34,770	31,140	32,315
Imports	2,014	1,938	1,952	1,785	1,952	2,954	2,724	4,422	3,319	1,878	2,131	2,286
DR plus 15% PRM	1,118	1,187	1,200	1,510	2,036	2,158	2,278	2,345	2,314	1,980	1,244	1,088
CAM & RMR	5,636	5,638	5,602	5,581	5,631	5,654	5,822	5,823	5,832	5,825	5,895	5,880
Total	33,871	33,201	33,774	35,587	38,794	44,671	49,281	52,753	46,609	38,776	34,664	35,837
Total/RAR	**102.1%**	**102.6%**	**103.8%**	**102.9%**	**102.9%**	**102.3%**	**100.5%**	**100.3%**	**100.3%**	**101.1%**	**101.1%**	**101.4%**

Source: Aggregated LSE Monthly RA Filings.

In 2015, total committed RA resources, including DR, ranged from 38,794 MW in May to 52,753 MW in August. These resources enabled CPUC jurisdictional LSEs to meet between 100 and 103 percent of total procurement obligations in each summer month. Actual peak demand occurred on September 10, 2015 at 47,252 MW.

Figure 3 reflects 2015 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 2015 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.)	32,798	37,955	42,651	45,747	40,409
Forward Commitment Obligation	37,718	43,648	49,048	52,609	46,470
Total RA Resources Committed	38,794	44,671	49,281	52,753	46,609
Actual Peak Load (CAISO)	33,228	41,914	42,299	46,822	47,252

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

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 due to insufficient data from the CAISO we are again unable to provide this information for 2015.

To give one a sense of the how much the chart would change if we had been able to include the aggregate non-CPUC-jurisdictional LSEs information we provide the August load ratios for 2015. In 2015, non-CPUC-jurisdictional LSEs aggregate load share for August was 7.7% of total CAISO load forecast.[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.14-06-050, the CPUC adopted the 2015 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 2015 are summarized in Table 5. CPUC-jurisdictional LSE procurement exceeded local RA obligations in each of the five local areas by 2 to 30%. Aggregate minimum procurement across all local areas exceeded local RA requirements by 13% in 2015. 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' load forecast and a decrease in non-IOU LSE's load forecast 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 2015, CPUC-Jurisdictional LSEs

Local Areas in 2015	Total LCR	CPUC-Jurisdictional Local Requirement	Minimum Physical Resources per Month	Local RMR & CAM Credit	Local DR	Minimum Procurement/ Local Requirement
LA Basin	9,097	8,289	8,307	2,188	1,020	113%
Big Creek/Ventura	2,270	1,760	2,075	667	218	130%
San Diego-IV	3,910	3,910	3,920	49	55	102%
Greater Bay Area	4,231	3,567	4,126	1,312	72	122%
Other PG&E Areas	5,719	5,282	5,534	299	251	110%
Totals	**25,227**	**22,809**	**23,963**	**4,514**	**1,615**	**113%**

[22] Local Capacity Requirement (LCR) studies and materials for 2015 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.

In 2015, the true-up process also included flexible RA. LSEs had to file revised load forecast from July to December, which were used to establish revised load ratios to reallocate flexible requirement for the second half of 2015.

In the allocation cycle for 2015, LSEs submitted revised August forecasts to the CEC on March 17, 2015 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 9, 2015, 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.

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' load forecast and a decrease in non-IOU LSEs' load forecast, 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 19, 2016, Energy Division issued a data request to all 23 CPUC-jurisdictional LSEs (comprised of three IOUs and 20 ESPs) asking for monthly capacity prices paid by (or to) LSEs for every RA capacity contract covering the 2015-2019 compliance years. The data request was confined to RA-only capacity contracts bought or sold covering the period from January 2015 – December 2019. Since RA prices can vary by month, the data request asked for specific monthly prices from each contract. QF contracts and imports were excluded from the data set.

Of the 23 LSEs that were sent the data request, Energy Division received ten responses (from three IOUs and seven ESPs), which consisted of a combined 2,321 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 2015 and 2016. This is as expected, since at the time that the data was collected the 2015 RA compliance years had ended, and there had only been a year-ahead showing and a few month ahead showings for 2016 compliance year.

In an attempt to get a better understanding of the magnitude of the data set, we compare the data set to 2015 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 2015, the sum of monthly contracted capacity represents approximately 20% of the 2015 monthly sum of RA requirements net CAM, RMR and DR allocations.[24] 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 2015 capacity is far from complete, it nevertheless provides important insights into overall RA pricing in that year. If we use the aggregate 2015 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 2016 the sum of monthly contracts represent about 31%, the 2017 to 2019 data represents about 33%.[25]

Table 6. Capacity Prices by Compliance Year, 2015-2016

	2015 Capacity	2016 Capacity	2017 - 2019 Capacity
Contracted Capacity (MW)	93,415	84,663	85,981
Percentage of total contracted MW in dataset	35%	32%	33%
Weighted Average Price ($/kW-month)	$3.09	$2.96	
Average Price ($/kW-month)	$2.75	$2.63	
Minimum Price ($/kW-month)	$0.09	$0.27	
Maximum Price ($/kW-month)	$26.54	$26.54	
85% of MW at or below ($/kW-month)	$5.24	$4.25	

[24] The 20% is calculated by dividing the sum of contracted capacity in 2015 (93,415 MW) by the sum of all 2015 monthly RA obligations net of CAM, RMR, and DR allocations (468,454 MW).
[25] To protect confidentiality, the price from 2017-2019 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 2016 Net Qualifying Capacity list.[26] Local RA Capacity areas are described in Section 3.3 of the report.

Table 77 below presents the summary statistics from the data set. All prices are in units of nominal dollars per kW-month. The data set represents 264,060 MW-months of capacity under contract. Of that capacity, 53% is located in the North of Path 26 (NP-26) Zone and 47% is located in the South of Path 26 (SP-26) Zone.[27] The data also show that 63% of the total capacity is located in local areas, with 37% located in the CAISO system area. Of the local RA capacity reported, the majority – 69% – is located in one of the SP-26 local areas; the remaining 31% is located in an NP-26 local area. The CAISO system RA has the opposite breakdown, with 91% of capacity located in the NP-26 Zone and only 9% of System RA capacity located in the SP-26 Zone.[28]

Table 7. Aggregated RA Contract Prices, 2015-2019

	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)	264,060	140,413	123,647	**167,143**	52,588	114,555	**96,917**	87,825	9,092
Percentage of Total Capacity in Data Set	**100%**	53%	47%	**63%**	31%	69%	**37%**	91%	9%
Number of Monthly Values	**2,321**	1,097	1,224	**1,780**	667	1,113	**541**	430	111
Weighted Average Price ($/kW-month)	**$2.93**	$2.45	$3.47	**$3.21**	$2.32	$3.62	**$2.45**	$2.53	$1.59
Average Price ($/kW-month)	**$2.74**	$2.26	$3.17	**$2.97**	$2.38	$3.32	**$1.97**	$2.06	$1.61
Minimum Price ($/kW-month)	**$0.09**	$0.60	$0.09	**$0.09**	$0.65	$0.09	**$0.60**	$0.60	$0.79
Maximum Price ($/kW-month)	**$26.54**	$11.47	$26.54	**$26.54**	$4.00	$26.54	**$11.47**	$11.47	$4.20
85% of MW at or below ($/kW-month)	**$4.25**	$3.00	$4.34	**$4.25**	$3.00	$4.34	**$3.00**	$3.00	$1.83

[26] The 2016 Net Qualifying Capacity list can be found at http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

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

[28] 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 $2.93/kW-month. This is $0.30 lower than the weighted average price reported in the 2013/2014 RA price analysis. The weighted average price for SP-26 capacity (including local and system RA) is $3.47/kW-month, which is about 42% higher than the NP-26 weighted average price of $2.45/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 $4.34/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 4 -Figure 6. Figure 4 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 63% 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 4. Price Curves for RA Capacity Contracts, 2015-2019 Compliance Years

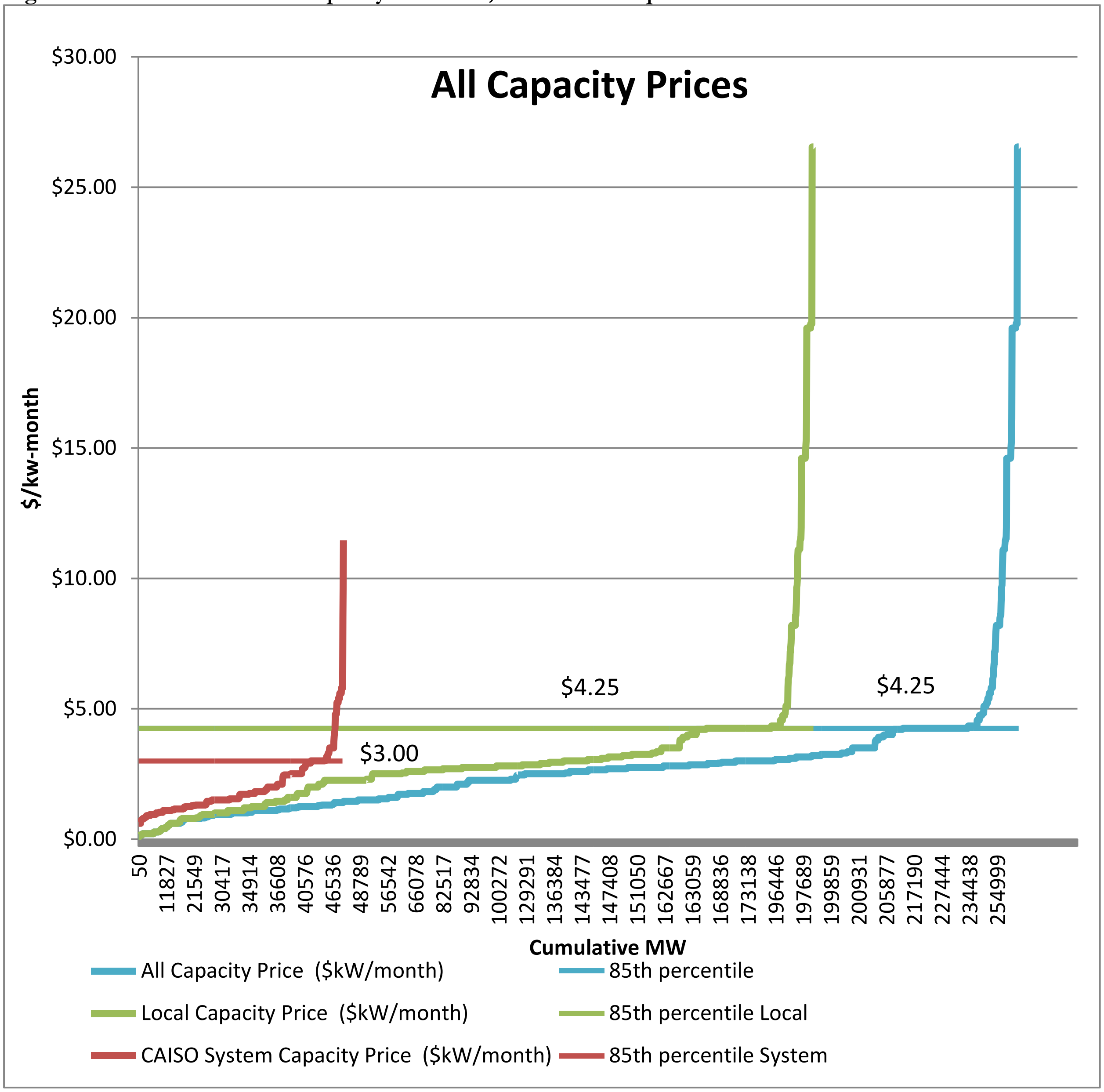


Figure 5. RA Price Curves for Resources North of Path 26, 2015- 2019

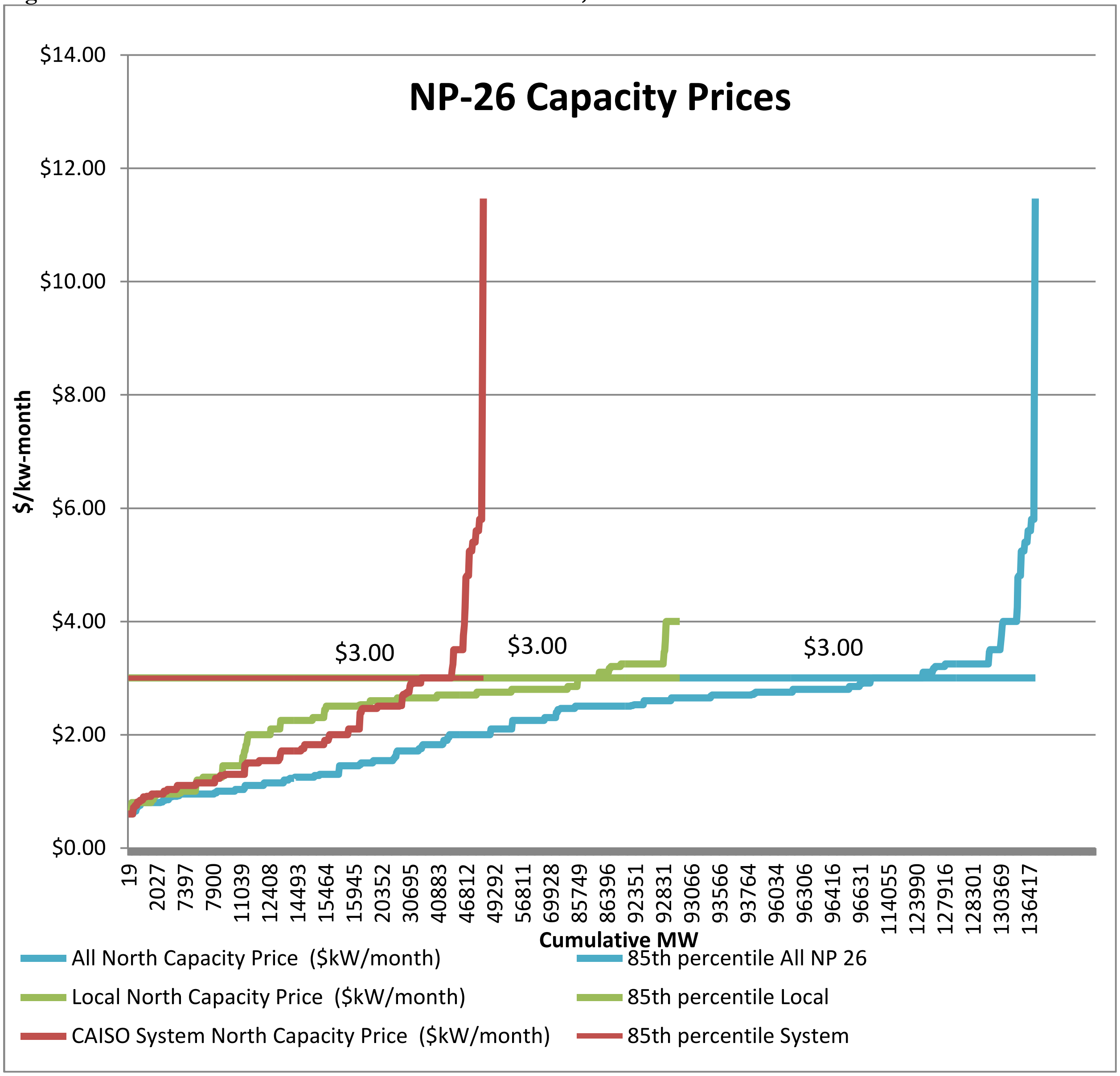


Figure 5 displays price curves for contracted capacity north of Path 26. Like Figure 4, the price curves are differentiated by local and system RA capacity. In contrast to the statewide aggregate data, the majority of contracted capacity north of Path-26 were resources *not* located in local areas. The weighted 85th-percentile contract price of system RA Capacity is the same as local RA at $3.00/kw-month, indicating that there is generally not a premium placed on Local RA capacity north of Path 26. There are about the same price outliers in the system RA capacity curve than there are in the local RA capacity curve.

Figure 6 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 \$2.51/kW-month more than for System RA. This is much higher than the difference of \$1.17/kW-month reported in the 2013/2014 RA report.

Figure 6. RA Price Curves for Resources South of Path 26, 2015-2019

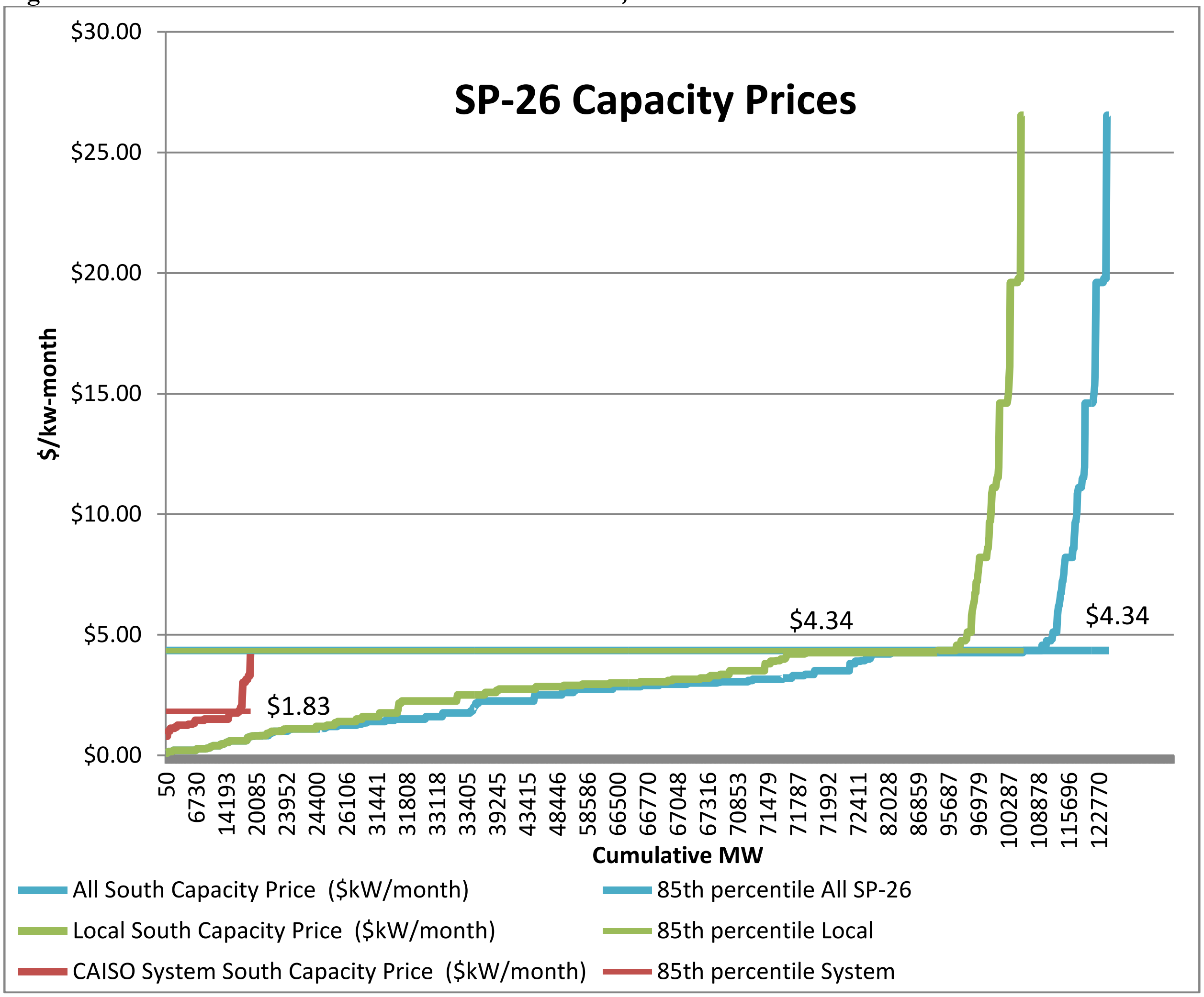


Table 8 reports capacity prices by local capacity area. The San Diego Local Area has the highest weighted average price and the highest maximum price. LA Basin local area has the highest 85th-percentile price. The 85th-percentile price indicates that 85 percent of the contracted MW in the LA Basin local area were procured at prices of $5.10/kW-month or below. According to the average weighed price and the 85th percentile price, LA Basin capacity is more expensive than Big Creek Ventura capacity, which is the same in the 2013/2014 RA resport. Looking at the weighted average price of local areas in the North, the data suggest that Other PG&E area local capacity is more expensive than Bay Area local capacity. However, given the limited data available for Other PG&E Local Areas (only 3,459 MW of contracted capacity, which is a little more than 7% of the contracted capacity in the Bay Area and only about 1.3% of the total data set), it is not possible to draw any definitive conclusions.

Table 8. Capacity Prices by Local Area, 2015-2019

	LA Basin	Big Creek/Ventura	Bay Area	Other PG&E Area	San Diego-IV	CAISO System
Contracted Capacity (MW)	21,644	58,955	49,129	3,459	33,956	96,917
Percentage of Total Capacity in Data Set	8.2%	22.3%	18.6%	1.3%	12.9%	36.7%
Weighted Average Price ($/kW-month)	$3.44	$3.41	$2.30	$2.55	$4.11	$2.45
Average Price ($/kW-month)	$2.99	$3.05	$2.19	$2.67	$3.83	$1.97
Minimum Price ($/kW-month)	$0.15	$0.16	$0.65	$0.65	$0.09	$0.60
Maximum Price ($/kW-month)	$16.12	$15.34	$4.00	$3.50	$26.54	$11.47
85% of MW at or below ($/kW-month)	$5.10	$4.34	$3.00	$3.00	$4.25	$3.00

The monthly weighted average capacity prices shown in

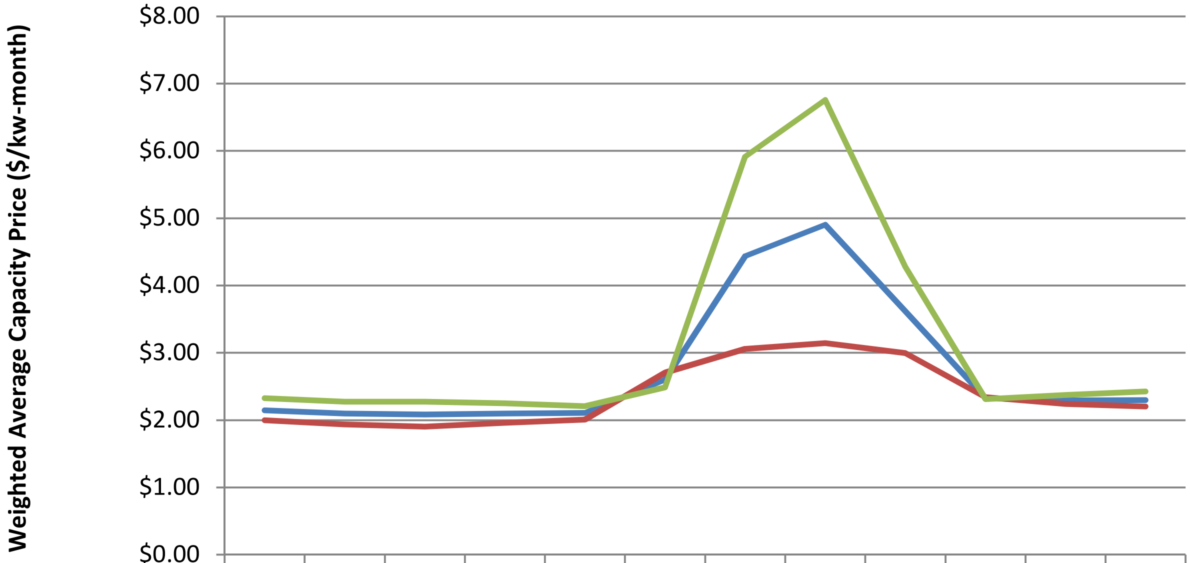
Table 9 below illustrate that capacity prices are higher from July through September. This is what we would expect to see, given the high demand in the summer months.

Table 9. RA Capacity Prices by Month, 2015-2019

	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	18,360	7%	$2.14	$0.19	$4.34	$3.00
February	17,291	7%	$2.10	$0.09	$4.34	$3.00
March	16,943	6%	$2.08	$0.09	$4.34	$3.05
April	17,671	7%	$2.10	$0.09	$4.34	$3.00
May	20,768	8%	$2.11	$0.28	$5.10	$3.80
June	22,542	9%	$2.60	$0.74	$5.80	$4.25
July	27,712	10%	$4.44	$0.80	$19.77	$7.22
August	31,087	12%	$4.90	$0.80	$26.54	$7.87
September	28,125	11%	$3.62	$0.80	$11.10	$5.24
October	23,053	9%	$2.33	$0.46	$5.10	$3.00
November	20,557	8%	$2.29	$0.28	$4.34	$3.00
December	19,952	8%	$2.30	$0.37	$4.34	$3.00

Figure 7 graphs the weighted average capacity prices by month and zone, revealing the large difference in prices for capacity in the north and in the south during summer months. The higher prices in the south may reflect lower supply levels, accompanied by higher demands during summer. They may also reflect the more constrained local capacity areas in Southern California.

Figure 7. Weighted Average RA Capacity Prices by Month and Zone



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
All Prices	$2.14	$2.10	$2.08	$2.10	$2.11	$2.60	$4.44	$4.90	$3.62	$2.33	$2.29	$2.30
NP 26 Prices	$2.00	$1.94	$1.90	$1.96	$2.01	$2.71	$3.06	$3.14	$2.99	$2.34	$2.24	$2.20
SP 26 Prices	$2.33	$2.28	$2.28	$2.25	$2.21	$2.49	$5.92	$6.75	$4.28	$2.31	$2.37	$2.43

Figure 8 graphs the contracted capacity by months and year. As expected, there is a downward trend in total capacity contracted each summer for future years. Because there is more capacity contracted in each year for July-September, there is more contracted capacity overall in 2015 than 2016. Note that the data set was collected at the beginning of 2016, which means the 2015 RA compliance years had concluded. [29]

[29] To protect confidentiality, 2017-2019 data can not be published.

Figure 8. Contracted RA Capacity by Month, 2015- 2016

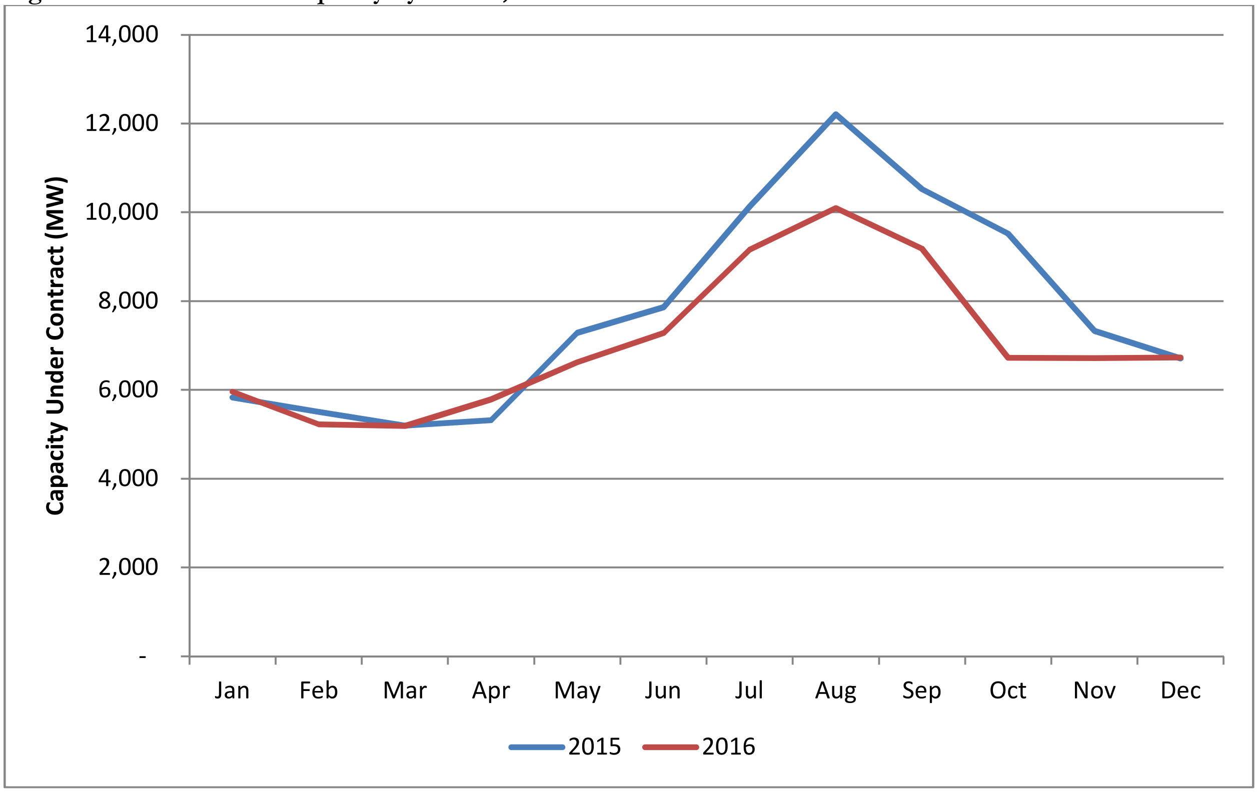


Figure 9. Weighted Average Capacity Prices by Month, 2015-2016

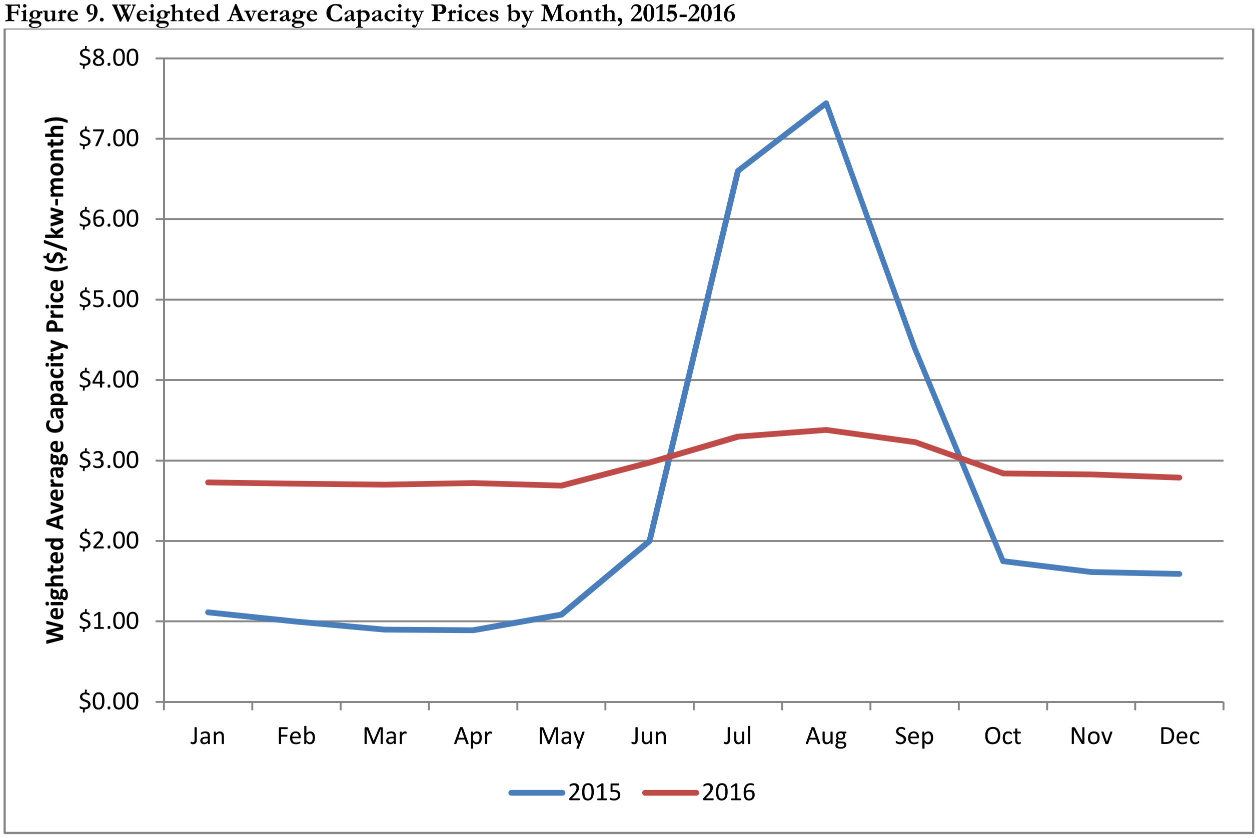


Figure 9 graphs the weighted average capacity prices by month and year. Prices are highest during the summer months for 2015 and 2016. The prices show a steady downward trend for June-September the farther out the contracted year is. This is consistent with the trend we saw in the 2013/2014 RA report capacity price analysis. [30]

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,[31] 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 2015, the RMR agreements for the Huntington Beach Synchronous condensers and Dynegy Oakland, LLC generating units were extended through calendar year 2016 to ensure reliability. [32] 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;
- Insufficient RA resources in an LSE's annual or monthly RA plan;

[30] To protect confidentiality, the prices from 2017-2019 can not be published.
[31] D.06-06-064, Section 3.3.7.1.
[32] CAISO Capacity Procurement Mechanism Overview Presentation, March 3, 2011, http://www.caiso.com/Documents/CapacityProcurementMechanismOverview.pdf

- 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.[33]

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 resolve 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.[34]

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). All potential CPM designations, except risk of retirement designation, will be covered through this process.

[33] CAISO Reliability BPM, version 30, page 147.
https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Reliability%20Requirements
[34] CAISO Capacity Procurement Mechanism Overview Presentation, March 3, 2011,
http://www.caiso.com/Documents/CapacityProcurementMechanismOverview.pdf

Table 10 shows CAISO's CPM designation from 2012 to 2015.

Table 10. CAISO CPM Designation from 2012-2015

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
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
INLDEM_5_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
GWFPWR_1_UNITS	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

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.

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. 2013-2016 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	7/31/2017	SCE	47.00
BUCKBL_2_PL1X3	8/1/2010	7/31/2020	SCE	490.00
CENTER_6_PEAKER	8/1/2007	7/31/2017	SCE	47.00
ETIWND_6_GRPLND	8/1/2007	7/31/2017	SCE	46.00
HINSON_6_LBECH1- HINSON_6_LBECH4	6/1/2007	5/31/2017	SCE	260.00
MIRLOM_6_PEAKER	8/1/2007	7/31/2017	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	10/31/2024	SCE	47.20

2016 Resources Authorized for CAM Due to Reliability (Incremental)

Scheduling Resource ID	CAM Start Date	CAM End Date	Authorized IOU	August NQC*
ELKHIL_2_PL1X3	1/1/2016	12/31/2020	SCE	200.00

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

D.10-12-035[35] 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.[36] 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.[37]

In 2013, PG&E had 21 CHP contracts whose costs and benefits were allocated to all customers. These CHP contracts amounted to 589 MW of RA credit.[38] These RA capacity credits were allocated in the monthly CAM allocation process beginning with the January 2013 compliance month. In 2014, PG&E had total of 26 CHP contracts whose costs and benefits were allocated to all customers. These CHP contracts amounted to 1,027 MW of RA credit. In 2015, PG&E had total of 30 CHP contracts that were allocated. These contracts amounted to 1,340 MW of RA credit. In 2014, SCE had 11 CHP contracts that received CAM treatment. These CHP contracts amounted to 757 MW of RA credit.[39] In 2015, SCE had total of 12 CHP contracts that were allocated as CAM resources. These contracts amounted to 829 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
CONTAN_1_UNIT	8/1/2012	6/30/2015	PG&E	18.04

[35] http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/128624.htm
[36] CHP Program Settlement Agreement Term Sheet 13.1.2.2
http://docs.cpuc.ca.gov/PUBLISHED/GRAPHICS/124875.PDF
[37] 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."
[38] August NQC values are used in this calculation.
[39] August NQC values are used in this calculation.

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

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	4/1/2016	3/30/2023	SCE	13.61

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 2015, a total of 2,554 MW of DR RA credit was allocated to benefiting LSEs to meet August RA obligations. 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.

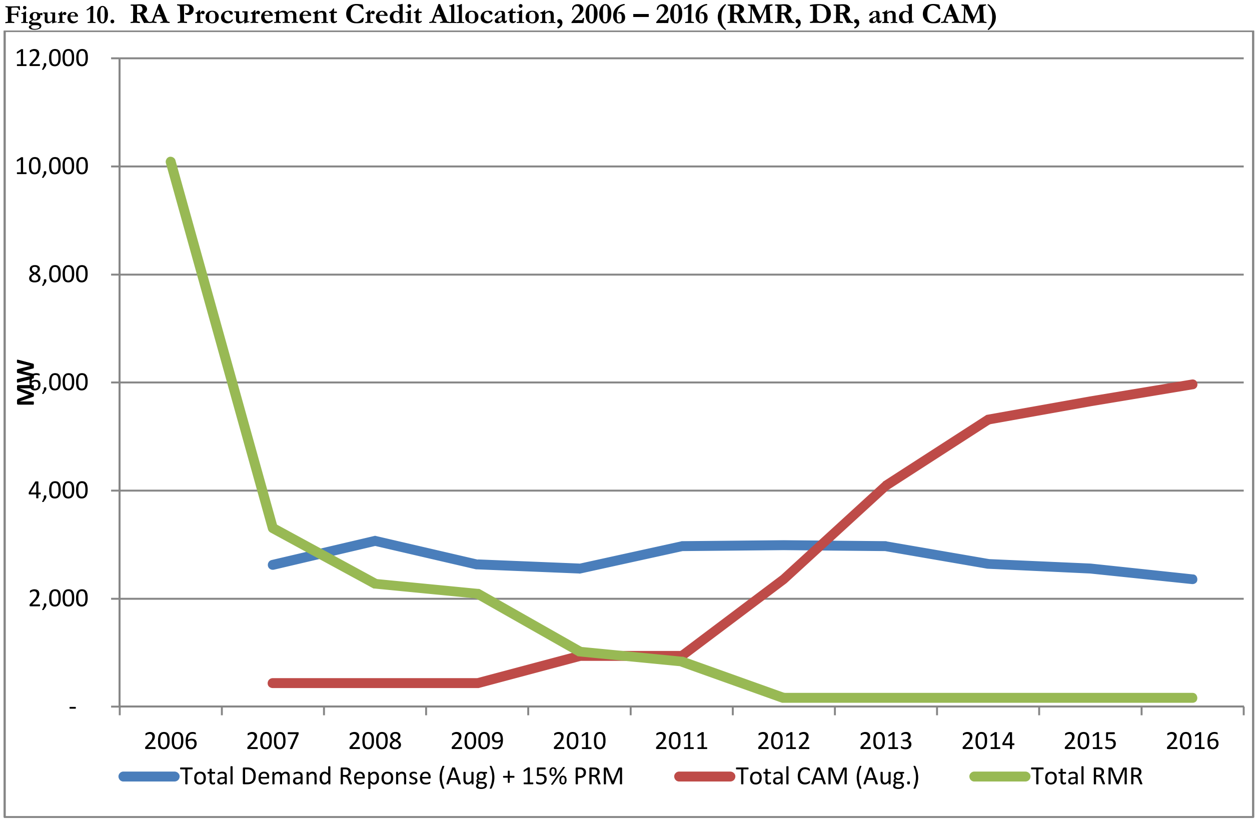
Table 13 and Figure 10 illustrate the amount and type of procurement credit that have been allocated since the beginning of the RA program. The graph reflects the decline in RMR units and the increase in CAM units. DR RA credits have slightly declined since 2013. The total amount of capacity procured through DR, CAM and RMR for August 2015 was 8,371 MW. This is 16% of the total CPUC-jurisdictional LSE obligation for August 2015 (52,609 MW). In August 2016, total CAM procurement reached 5,964 MW where RMR procurement consisted of only 165 MW (CPUC jurisdictional LSEs were allocated 152.34 MW of the 165 MW in August 2015).

[40] D.12-06-025.

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



4.5 RA Resource Commitments into CAISO's Markets—RA Capacity Bidding and Scheduling Obligations

The scheduling coordinators for the RA capacity procured by the LSE have an obligation to make the capacity listed in the monthly supply plan available to the ISO. The manner in which this occurs depends on the resource type. However, the general requirement for RA generation units is that they submit economic bids or self-schedule into the Intergraded Forward Market (IFM)/Day Ahead Market (DAM). They must also submit $0/MW RUC availability bids for all hours for the month the resource is available. Any RA capacity that does not submit a bid in the IFM or RUC mechanism must submit an economic bid or self-schedule into the real time market. If the SC fails to submit a bid for the resource through these mechanisms, the ISO will generate one for them.

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 2015

The addition of new capacity slowed somewhat in 2015 in comparison to the previous several years with 1,004.94 MW of new generation coming online and 530.34 MW retiring for a net gain of 474.60 MW.[44] All new facilities were renewable generators with the vast majority being solar PV.

Table 14 lists the new and retiring facilities for 2015. 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 2015, the net dependable capacity of facilities that came online was nearly twice the size of 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 2014-2016 are available at: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

Table 14. New NQC Resources Online in 2015

Resource ID	Resource Name	Technology	NQC[45]	Net Dependable Capacity
7STDRD_1_SOLAR1	Shafter Solar	Solar PV	13.80	20.00
ADERA_1_SOLAR1	Adera Solar	Solar PV	-	20.00
ALLGNY_6_HYDRO1	Salmon Creek Hydroelectric Project	Hydro	0.26	0.52
ATWEL2_1_SOLAR1	CED Atwell Island West, LLC	Solar PV	13.80	20.00
BKRFLD_2_SOLAR1	Bakersfield 111	Solar PV	1.20	1.38
BLCKWL_6_SOLAR1	Blackwell Solar	Solar PV	8.28	12.00
CAMLOT_2_SOLAR1	Camelot	Solar PV	31.16	45.00
CATLNA_2_SOLAR2	Catalina Solar 2	Solar PV	13.47	18.00
CENTER_2_SOLAR1	Pico Rivera	Solar PV	-	0.90
CHINO_2_SOLAR2	Kona Solar - Terra Francesca	Solar PV	-	1.49
CORCAN_1_SOLAR1	CID Solar	Solar PV	13.80	20.00
CORCAN_1_SOLAR2	Corcoran City	Solar PV	7.59	11.00
CUMBIA_1_SOLAR	Columbia Solar Energy	Solar PV	-	19.00
DELAMO_2_SOLAR1	Golden Springs Bldg H	Solar PV	1.12	1.50
DELAMO_2_SOLAR2	Golden Springs Bldg M	Solar PV	1.31	1.75
DELSUR_6_DRYFRB	Dry Farm Ranch B	Solar PV	3.46	5.00
DELSUR_6_SOLAR1	Summer Solar North	Solar PV	4.49	6.50
DIXNLD_1_LNDFL	Zero Waste Energy	Biogas	1.30	1.60
EEKTMN_6_SOLAR1	EE K Solar 1	Solar PV	2.30	20.00
ELCAP_1_SOLAR	2097 Helton	Solar PV	1.04	1.50
ENERSJ_2_WIND	ESJ Wind Energy	Wind	24.82	155.10
GARNET_1_SOLAR2	Garnet Solar Power Generation Station 1	Solar PV	2.77	4.00
GARNET_2_WIND1	Phoenix	Wind	1.79	11.20
GARNET_2_WIND2	Karen Avenue Wind Farm	Wind	1.30	11.70
GOOSLK_1_SOLAR1	Goose Lake	Solar PV	8.28	12.00
HOLSTR_1_SOLAR2	Ecos Energy Hollister Project	Solar PV	1.04	1.50
KERMAN_6_SOLAR1	Fresno Solar South	Solar PV	-	1.50
KERMAN_6_SOLAR2	Fresno Solar West	Solar PV	-	1.50
KNTSTH_6_SOLAR	Kent South	Solar PV	-	20.00
LAMONT_1_SOLAR1	Regulus Solar, LLC	Solar PV	41.54	60.00
LAMONT_1_SOLAR3	Woodmere Solar Farm	Solar PV	10.38	14.99
LAMONT_1_SOLAR4	Hayworth Solar Farm	Solar PV	18.46	26.66
LAMONT_1_SOLAR5	Redcrest Solar Farm	Solar PV	15.60	16.66
LEPRFD_1_KANSAS	Kansas	Solar PV	13.85	20.00
LHILLS_6_SOLAR1	Lost Hills Solar	Solar PV	13.80	20.00

[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.

LITLRK_6_SOLAR1	Lancaster Little Rock C	Solar PV	3.45	5.00
LIVEOK_6_SOLAR	Pristine Sun Harris	Solar PV	0.87	1.25
MARCPW_6_SOLAR1	Maricopa West Solar PV	Solar PV	13.85	20.00
MERCED_1_SOLAR1	Mission Solar	Solar PV	-	1.50
MERCED_1_SOLAR2	Merced Solar	Solar PV	-	1.50
MNDOTA_1_SOLAR1	North Star Solar 1	Solar PV	41.40	60.00
MNDOTA_1_SOLAR2	Citizen Solar B	Solar PV	-	5.00
MRLSDS_6_SOLAR1	Morelos Solar	Solar PV	14.04	15.00
OASIS_6_SOLAR1	Morgan Lancaster I	Solar PV	-	1.50
OLDRV1_6_SOLAR	Old River One	Solar PV	13.85	20.00
PADUA_2_SOLAR1	Kona Solar - Rancho DC #1	Solar PV	-	1.75
PLAINV_6_BSOLAR	Western Antelope Blue Sky Ranch A	Solar PV	-	20.00
PLAINV_6_SOLAR3	Sierra Solar Greenworks LLC	Solar PV	-	20.00
PMDLET_6_SOLAR1	Palmdale East	Solar PV	8.20	10.00
PMPJCK_1_SOLAR1	Pumpjack Solar I	Solar PV	13.44	19.48
PUTHCR_1_SOLAR1	Putah Creek Solar Farm	Solar PV	1.37	1.98
RTREE_2_WIND1	Rising Tree 1	Wind	12.67	79.20
RTREE_2_WIND2	Rising Tree 2	Wind	3.17	19.80
RTREE_2_WIND3	Rising Tree 3	Wind	15.57	99.00
RVSIDE_6_SOLAR1	Tequesquite Landfill Solar Project	Solar PV	7.02	7.50
S_RITA_6_SOLAR1	Sun Harvest Solar	Solar PV	-	1.50
SKERN_6_SOLAR1	Algonquin SKIC 20 Solar	Solar PV	13.80	20.00
SLST13_2_SOLAR1	Quinto Solar PV Project	Solar PV	100.72	107.60
SLSTR1_2_SOLAR1	Solar Star 1	Solar PV	205.23	310.00
SLSTR2_2_SOLAR2	Solar Star 2	Solar PV	188.59	276.00
TWISSL_6_SOLAR1	Coronal Lost Hills, LLC	Solar PV	13.80	20.00
USWND2_1_WIND1	Golden Hills A	Wind	6.75	42.96
USWND2_1_WIND2	Golden Hills B	Wind	6.75	42.96
VALLEY_5_SOLAR1	Kona Solar - Meridian #1	Solar PV	-	1.49
VALLEY_5_SOLAR2	SunE DB APNL, LLC	Solar PV	14.97	20.00
VEGA_6_SOLAR1	Vega Solar	Solar PV	-	20.00
VICTOR_1_LVSLR1	Lone Valley Solar Park 1	Solar PV	-	10.00
VICTOR_1_LVSLR2	Lone Valley Solar Park 2	Solar PV	-	20.00
VICTOR_1_SOLAR2	Alamo Solar	Solar PV	-	20.00
VICTOR_1_SOLAR3	Adelanto Solar 2	Solar PV	4.85	7.00
VICTOR_1_SOLAR4	Adelanto Solar	Solar PV	-	20.00
VICTOR_1_VDRYFA	Victor Dry Farm Ranch A	Solar PV	-	5.00
VICTOR_1_VDRYFB	Victor Dry Farm Ranch B	Solar PV	-	5.00
WAUKNA_1_SOLAR2	Corcoran 2	Solar PV	14.78	19.75
		Total	**1004.95**	**2002.67**

Table 15. Resources that Retired in 2015

Resource ID	Resource Name	Technology	NQC
BEARCN_2_UNITS	Geysers Bear Canyon Aggregate	Geothermal	13.00
BLULKE_6_BLUELK	Blue Lake Power	Biomass	9.04
CWATER_7_UNIT 3	Coolwater Station 3 Aggregate	Steam Turbine	245.30
CWATER_7_UNIT 4	Coolwater Station 4 Aggregate	Steam Turbine	245.90
GATES_6_PL1X2	Gates Peaker	Peaker	0.00
KEARNY_7_KY1	Kearny Gas Turbine Unit 1	Peaker	16.00
MNTAGU_7_NEWBYI	Gas Recovery Sys. (Newby Island 2)	Biogas	1.10
SEARLS_7_WESTEN	North American Westend	CHP	0.00
		Total	**530.34**

Source: 2015-2016 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 2010 through 2016

Table 16 shows aggregate NQC values from the CAISO NQC lists for 2010 through 2015.[48] While many large resources have become available over the previous few years, the total NQC has not grown accordingly, partially due to resources retiring and the effect of new CPUC QC counting conventions that decreased the NQC of many intermittent resources. This change is in part attributable the gradual increase in the number of resources that receive a monthly NQC value rather than an annual value. In addition to those resources that now receive a monthly value pursuant to changes in QC counting conventions adopted by the Commission (most notably, cogeneration and hydro resources are now provided monthly values), several larger thermal resources have begun to voluntarily supply information to support monthly NQC values in light of performance due to differing ambient weather conditions. Accounting for decreases in performance at higher temperatures can result in lower August NQC values, and thus a decrease in the aggregate reported NQC over time. For those facilities that were given monthly NQC values, this table shows August NQC values.

The total 2016 NQC (as reported on the CAISO 2016 NQC list) increased by 177 MW from the 2015 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 2013, 2014, and 2015. 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.

[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.

Table 16. Final NQC Values for 2011 – 2016

Year	Total NQC (MW)	Total Number of Scheduling Resource IDs	Net NQC Change (MW)	Net Gain in CAISO IDs on List
2011	51,929	647		
2012	50,442	657	-1,487	10
2013	53,336	733	2,894	76
2014	53,112	765	-224	32
2015	52,996	802	-116	37
2016	53,173	972	177	170
2011-16			**1,244**	**325**

Source: NQC lists from 2011 through 2016.

6 Compliance with RAR

CPUC staff continued the implementation of the RA program during 2015 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 2014 to discuss general compliance rules as well as to highlight changes in procedures and filing rules new to the 2015 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 2015 filing guide and templates were made available to LSEs in September 2014. Flexible capacity obligations by category has been added to the 2015 templates. Changes were made to implement the new RA rules adopted in D.14-06-050, particularly flexible capacity procurement requirements and RA program refinements. As in previous years, the CPUC required that all filings 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 2015, 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 2015 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 2015, the Commission issued 38 citations for violations and initiated 4 enforcement cases, collecting $161,600 and $847,500 respectively from LSEs. In 2015, the Commission issued six citations and took no enforcement action, ultimately collecting $33,000 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, Commerce Energy, EDF Industrial, Glacial Energy	$33,000	0		0
Total	**38**		**$161,600**	**4**		**$847,500**

7 Generator Performance and Availability

To facilitate and ensure that generators perform in accordance with their RA capacity contracts, and are available as per agreement, the CAISO introduced Standard Capacity Product (SCP) provisions in 2010. The SCP provisions monitor and penalize generators' Scheduling Coordinators (SCs) based on performance and availability. SCP penalties apply to generation confirmed as an RA resource for the month, whether or not it is located within CAISO territory.

In 2014, the ISO conducted a stakeholder process that reviewed the current availability incentive mechanism and specifically addressed the development of a flexible RA availability mechanism and new availability mechanism price.

Resource Adequacy Availability Incentive Mechanisms (RAAIM) is the new mechanism that replaced the Standard Capacity Product (SCP) and ensures that RA capacity is available to the ISO. RAAIM was scheduled to take effect on March 1, 2016. However, due to implementation difficulty, it was not implemented until November 1, 2016.

RAAIM increases grid reliability and market efficiency by incentivizing RA resources to meet their bid obligation and provide energy to the market as contracted. RAAIM replaces SCP and is different in that is uses a resource's economic and self-schedule bids to evaluate resource adequacy. Resources that fail to meet the threshold can be penalized and resources that exceed the threshold can receive a payment. SCP also differs in that it exempted a large number of resources because of a limitation of evaluating availability based on forced outages. RAAIM adopted $3.79/kW-month using 60% of the CPM soft offer cap price which corresponds to a higher than average bilateral capacity price. Previously, the CPM was $70.88 per kW-year or $5.91/kW-month). [50]

[50] CAISO Tariff, Section 40.9.6.1(b), http://www.caiso.com/rules/Pages/Regulatory/Default.aspx

7.1 Performance and Availability for RA Resources in CAISO

On January 1, 2010, the CAISO implemented the SCP provisions for conventional generation. The SCP created an availability standard that was intended to be utilized by counterparties in bilateral capacity contracting as a performance metric that they could refer to. The product defines annual and monthly availability standards that are used for evaluating the performance of RA resources. SCP also provides incentives for RA capacity to participate in the energy market and meet a resource-specific must offer obligation through rewarding high performing resources and penalizing low performing resources. The adopted provisions include:

1.) Establish a standard product definition for Resource Adequacy (RA) capacity, to facilitate selling, buying, and trading capacity to meet RA requirements;

2.) Create a standard method to incent high performance from RA resources using performance incentives and non-availability charges;

3.) Create a Must Offer Obligation (MOO) for Ancillary Services (A/S) for all certified products on RA resources subject to an energy MOO;

4.) Create an annual process to review prequalification requests for units to be used in Real-Time Market (RTM) Pre-approved Unit Substitution Process; and

5.) Create a process to review requests for unit substitution that are not prequalified in the annual process.

For 2010, certain resources were exempt from SCP; these included DR and resources with QC values based on historical values. Beginning in 2011, resources with QC values based on historical values were added to SCP provisions, while DR remained exempt. Currently, DR resources continue to remain exempt.

The monitoring of the SCP entails a monthly review by the CAISO of all RA resources to determine whether the resource's monthly availability met the monthly availability standard. When an RA resource's availability exceeds the monthly availability standard by 2.5% or more, the resource becomes eligible for an availability incentive payment. When an RA resource's availability falls to 2.5% below the monthly availability standard, the resource becomes subject to a non-availability charge.[51] To maintain a revenue-neutral program, the performance payments for a particular month are drawn from the pool of performance penalties paid for the same month. The 2015 SCP price was tied to the Capacity Procurement Mechanism (CPM), which was $70.88 per kW-year ($5.91/kW-month).

The CAISO calculates the monthly availability standard using the historical forced outages of RA resources over the range of availability assessment hours for each month of the year for the past three years. The CAISO publishes these values annually on about July 1st, to be used for the coming compliance year.[52]

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[51]CAISO posts SCP information to the CAISO website here: http://www.caiso.com/Documents/2015MonthlyResourceAdequacyAvailabilityStandards.pdf

[52] Ibid.

The CAISO calculates individual resource availability by summing the total RA capacity reported as available in Outage Management System (OMS) for each availability assessment hour of the month, and dividing that value by the product of the facility's NQC and the number of availability assessment hours in the month. A resource is considered 100% available if the resource has no forced outages or temperature related ambient derates that reduce the available RA capacity during the availability assessment hours.

In contrast, non-resource specific (NRS) system resource availability (intertie availability) is not based on outages in OMS. The availability of a system resource is measured by its hourly offers (e.g. economic bids or self-schedules) to provide energy, per CAISO Tariff Section 40.9.7.2, *Availability Calculation for Non-Resource-Specific System Resources Providing Resource Adequacy Capacity*.

Table 18 below presents SCP data[53] for the period from January to December 2015. These data include: availability standards, charges, incentive payments, and performance. The table shows that in 2015 on average 29,826 MW[54] of RA capacity from generators and 1,456 MW[55] of RA capacity from interties were subject to SCP rules. Compared to 2014, this is about a 21% increase in the number of generator MW subject to SCP and about a 28% increase in the number of intertie MWs. The monthly availability standards ranged from 95.46% to 97.95% during 2015; actual availability of generators averaged 98.42%, which is an increase of 2.1% from the 2013 average of 96.4%. The actual monthly availability average for intertie resources slightly increased from 99.68% in 2013 to 99.95% in 2015.

[53] Data in Table 18 does not reflect adjustments made after publication on the ISO website.

[54] This does not include RA capacity that is grandfathered in because it predates the implementation of SCP availability standards.

[55] *Ibid.*

Table 18. 2015 RA Availability and SCP Payments

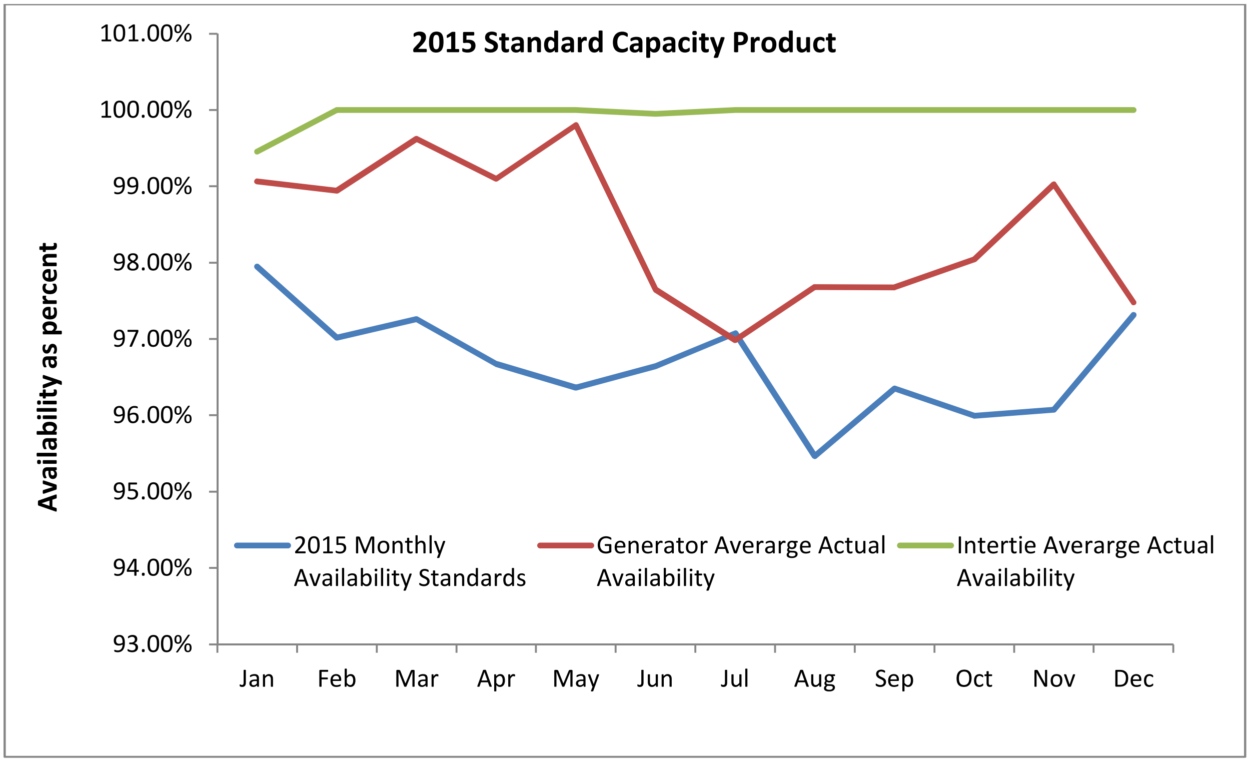
2015 Standard Capacity Product Report

	Resource Type	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Monthly Availability Standards	GENERATOR	97.95%	97.02%	97.26%	96.67%	96.36%	96.64%	97.07%	95.46%	96.35%	95.99%	96.07%	97.31%
	INTERTIE	97.95%	97.02%	97.26%	96.67%	96.36%	96.64%	97.07%	95.46%	96.35%	95.99%	96.07%	97.31%
Non-Availability Charges	GENERATOR	$398,875	$420,370	$201,860	$1,144,779	$10,816	$1,909,210	$2,812,857	$2,405,532	$1,872,299	$1,193,221	$454,492	$2,328,149
	INTERTIE	$4,141	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Availability Incentive Payment	GENERATOR	$0	$420,370	$201,860	$1,144,779	$10,816	$1,909,210	$1,420,591	$2,405,532	$1,872,299	$1,193,221	$454,492	$571,686
	INTERTIE	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Monthly Surplus	GENERATOR	$398,875	$0	$0	$0	$0	$0	$1,392,266	$0	$0	$0	$0	$1,756,462
	INTERTIE	$4,141	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Average Actual Availability (%)	GENERATOR	99.07%	98.94%	99.62%	99.10%	99.80%	97.65%	96.98%	97.68%	97.67%	98.04%	99.03%	97.48%
	INTERTIE	99.46%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Average RA Capacity (MW)	GENERATOR	25,048	25,309	26,881	26,866	29,634	30,984	36,309	38,089	34,094	29,799	27,793	27,101
	INTERTIE	1,373	1,346	1,318	1,087	1,230	1,268	1,274	2,773	1,635	1,214	1,492	1,461

Source: CAISO 2015 Standard Capacity Product Report,
http://www.caiso.com/Documents/2015StandardCapacityProductAnnualReport.pdf

Figure 11 illustrate the monthly availability standards and the average actual availability of both generators and interties in 2015. In 2015, interties show a higher average actual availability than the monthly availability standard for all months. This is roughly the same trend observed in the 2013 and 2014 performance of interties, as shown in Figure 12.

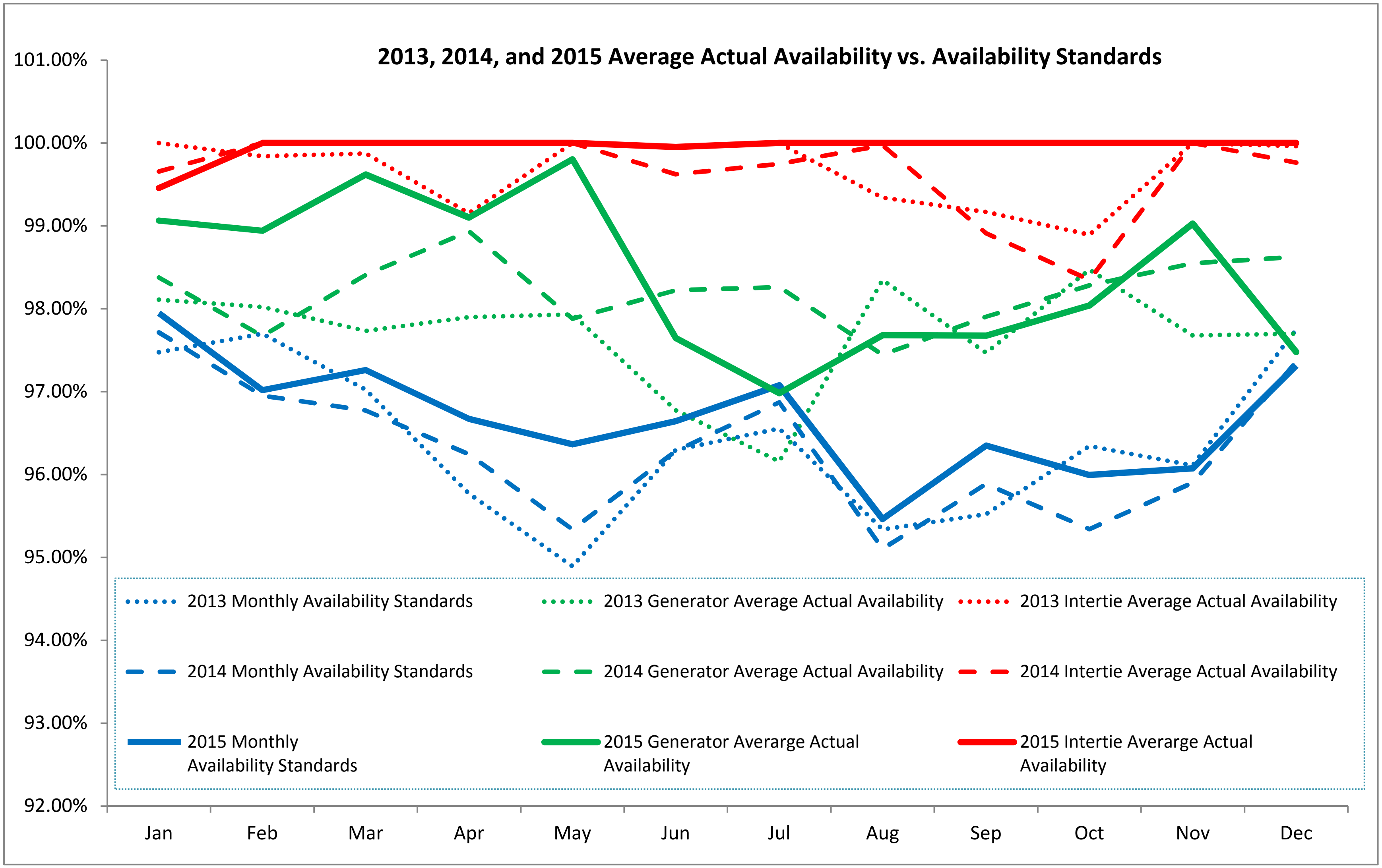
Figure 11. 2015 Average Actual Availability vs. Availability Standards (percent)



Source: 2015 Standard Capacity Product Report - http://www.caiso.com/Documents/2015StandardCapacityProductAnnualReport.pdf

Figure 12 graphs the average monthly availability for interties and generators from 2013- 2015 compared with the annual availability standards.

Figure 12. 2013-2015 Average Actual Availability vs. Availability Standards.



Source: CAISO 2013, 2014 & 2015 Standard Capacity Product Reports –

2015 Resource Adequacy Report

http://www.caiso.com/Documents/2015StandardCapacityProductAnnualReport.pdf

http://www.caiso.com/Documents/2014StandardCapacityProductAnnualReport.pdf

http://www.caiso.com/Documents/2013StandardCapacityProductAnnualReport.pdf