California Public Utilities Commission

December 16, 2016

Energy Division Proposals for Proceeding 14-10-010 Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local and Flexible Procurement Obligations for the 2016 and 2017 Compliance Years

Proposal 1: Retention of Current Allocation Method for the Flexible Capacity Requirements

Energy Division staff proposes to retain the current methodology of allocating flexible capacity requirements to CPUC-jurisdictional load serving entities (LSEs) based on peak load ratio shares. In order to allocate flexible capacity requirements to non-CPUC jurisdictional LSEs, the California System Operator (CAISO) uses a cost-causation methodology and in the past couple of years, various parties have proposed that the CPUC adopt a similar allocation methodology.

As explained in more detail below, staff proposes to retain its current methodology because a durable flexible product that could have implications for the CAISO's cost-causation methodology has not yet been developed, the current CAISO cost-causation methodology is problematic, and a cost-causation methodology could unduly burden bundled service customers.

CAISO determines flexible capacity needs in an annual study and allocates the flexible capacity needs according to the methodology detailed in its tariff, section 40.10.2. The tariff section states that:

> The CAISO will calculate the Local Regulatory Authority's allocable share of the Flexible Capacity Need as the average of the sum of its jurisdictional Load Serving Entities' change in load, minus the change in wind output, minus the change in solar PV output, minus the change in solar thermal output during the five highest three-hour net-load changes in the month.

This methodology is further explained in CAISO's Flexible Capacity Needs Assessment.[1] While CAISO uses its cost-causation methodology to allocate the flexible capacity needs to local regulatory authorities (LRAs) and LSEs, the CPUC adopted a peak load ratio share method in D.14-06-050, which allocates this requirement based on an individual LSE's contribution to the peak load. However, in this decision and in subsequent decisions, the Commission indicated that it intended to explore other methods of allocation based on cost-causation. In particular, in D.16-06-045, the Commission stated that:

> Again, we defer this issue to Track 2 and its consideration of a durable flexible requirement. We remain open to this proposal, including potential improvements such as the ideas offered by SDG&E in Track 2 or at another point in the future. We encourage Energy Division and parties to consider relevant proposals. For clarity, we note that any proposals need not rely on exactly the CAISO's method or the CAISO's results. Proposals may consider alternative means of achieving the goal of proper alignment of incentives.

[1] See CAISO, "Final Flexible Capacity Needs Assessment for 2017," pp. 17-18, available at http://www.caiso.com/Documents/FinalFlexibleCapacityNeedsAssessmentFor2017.pdf.

Energy Division staff has considered the issue of cost-causation and, based on a number of considerations, proposes to maintain the current load-ratio share allocation methodology adopted in D.1406-050.

First, the Commission and CAISO are currently working towards the development of a durable flexible product. While this may result in a continuation of the existing product, it is also possible that the flexible product could focus on a different flexibility need or multiple flexibility needs. For example, the focus could be on a one-hour need or a combination of one-hour, three-hour, and intra-hour needs. Energy Division staff recommend that the Commission not update the cost allocation methodology until the durable flexible product is defined, if at all, as the cost-causation methodology could change based on this further refined assessment of need.

Second, while the Commission has been clear that it could consider a different cost-causation methodology than that proposed and adopted by the CAISO, it makes sense to consider the CAISO's methodology at least initially. However, based on Energy Division staff's initial assessment, CAISO's current cost-causation methodology is problematic in part because it uses the average of percentages, which results in allocations that are not consistent with an overall assessment of need.

Energy Division staff developed the following example to illustrate the issue, which was presented at the Energy Division's November 9, 2016 workshop.

Figure 1. Example of Averaging Percentages

Top Net Load Ramps	**LSE1**	**LSE2**	**LSE3**	**Total Ramp**		**Top Net Load Ramps**	**LSE1**	**LSE2**	**LSE3**	**Total Ramp**
1	-40	50	0	10		1	-40	70	-20	10
2	25	50	25	100		2	25	50	25	100
3	25	10	5	40		3	25	10	5	40
				150		**Total**	10	130	10	150
						Percentage	7%	87%	7%	100%
1	-400%	500%	0%	100%						
2	25%	50%	25%	100%						
3	63%	25%	13%	100%						
Average	-104%	192%	13%							
Allocation	-156.25	287.5	18.75	150						

As this example illustrates, averaging the percentages can result in a misallocation of flexible needs, especially if an LSE has a large ramp compared to the total ramp or has load that moves in the opposite direction of the total ramp. For example, LSE1 in the above illustration (left side) would receive a negative allocation while LSE2 would receive a very high allocation because the LSEs' loads are not moving in the same direction during all ramps. A fairer allocation, would allocate based on the sum of the LSE's ramps (right side). Energy Division staff recommends that the Commission not adopt a cost causation methodology until the CAISO addresses its cost causation methodology and ensures an appropriate allocation among LRAs and LSEs.

Finally, Energy Division staff notes that flexible capacity need is largely driven by in-front of the meter solar resources, and to a lesser degree load, including the effect of behind-the-meter solar on load, as illustrated in the following table from CAISO's flexible capacity study.[2]

Table 1. Contribution to Maximum 3-Hour Continuous Net Load Ramp for 2016

Month	Average of Load contribution 2017	Average of solar PV contribution 2017	Average of BTM Solar contribution 2017	Average of Wind contribution 2017	Average of OOS Wind contribution 2017	Total percent 2017
January	49.09%	-47.68%	-2.66%	-0.52%	-0.05%	100%
February	31.99%	-63.00%	-3.77%	-0.77%	-0.47%	100%
March	27.28%	-63.69%	-8.15%	-1.28%	0.40%	100%
April	23.01%	-68.11%	-9.61%	0.71%	0.02%	100%
May	23.87%	-64.15%	-9.83%	-1.65%	-0.50%	100%
June	8.76%	-79.58%	-11.52%	-0.55%	0.41%	100%
July	11.66%	-78.87%	-11.11%	1.47%	0.17%	100%
August	-0.72%	-94.04%	-12.81%	5.93%	0.21%	100%
September	6.27%	-82.42%	-10.82%	-0.28%	-0.21%	100%
October	18.23%	-72.80%	-11.45%	1.61%	0.86%	100%
November	34.75%	-55.91%	-8.69%	-0.51%	-0.15%	100%
December	42.28%	-48.62%	-6.05%	-2.02%	-1.04%	100%

In light of the fact that renewable contracts remain with the IOUs and bundled service customers, it would not make sense to require bundled service customers to shoulder the flexible allocation associated with renewable contracts initially procured on their behalf, should this load migrate to other service providers. Unless and until this larger cost-allocation issue is addressed explicitly, Energy Division staff recommends that the Commission not adopt a cost-causation methodology, but rather allocate the requirement based on load-ratio share, under the assumption, at least for now, that all customers should pay for the aggressive renewables program that California has pursued.

[2] See CAISO, "Final Flexible Capacity Needs Assessment for 2017," p 19, available at http://www.caiso.com/Documents/FinalFlexibleCapacityNeedsAssessmentFor2017.pdf.

Proposal 2: Elimination of the Maximum Cumulative Capacity (MCC) Bucket Framework

Energy Division staff proposes to eliminate the maximum cumulative capacity (MCC) buckets. The original purpose of the MCC buckets was to ensure that load serving entities (LSEs) did not rely too heavily on resources with limited availability. In practice, however, the MCC buckets, as configured, do not prevent overreliance on use limited resource because they only apply to contractual provisions, not physical use limitations. Given that the MCC buckets currently serve no clear practical purpose, and are not binding, Energy Division staff proposes to eliminate them for the 2018 compliance year.

The Commission adopted maximum cumulative capacity (MCC) buckets early in the CPUC's resource adequacy (RA) program. As explained in D.12-06-025:

> During the development of the RA program in 2004 and 2005, concerns surfaced that LSEs might meet their RA obligations by procuring a large number of resources that were either contractually or operationally limited. This would have had an adverse impact on the reliability of the ISO's grid operations. To ensure that LSEs restricted their dependence on limited availability contracts, Energy Division, pursuant to the directives in D.05-10-042, created four resource categories known as the MCC buckets based on the hours of contractual availability. The RA Program now imposes procurement caps in the form of maximum percentage limits on resources procured that fall within each bucket. (D.12-06-025, p. 13.)

In D.12-06-025, the Commission revised the percentages applicable to the buckets based on updated load shapes, using those from 2009-2011, and also added a bucket for Demand Response (DR) resources. The hourly limits for all the existing buckets remain the same, and the hour limit for the DR bucket was chosen based on the fact that most DR programs are available a minimum of 24 hours in a month. Energy Division intended to allow all current DR programs to continue to count for RA within the new DR bucket construct. Table 1 below summarizes the resource categories.

Table 2. Summary of Resource Categories

Category	Resources may be categorized into one of the five categories shown below, according to their planned availability as expressed in hours available to run or operate per month (hours/month):
DR	Demand Response resources available for "greater than or equal to" 24 hours per month.
1	Greater than or equal to the ULR [Use Limited Resource] monthly hours. The requirements for May through September are: • May – 30 hours per month • June – 40 hours per month • July – 40 hours per month • August – 60 hours per month • September - 40 hours per month
2	"Greater than or equal to" 160 hours per month.
3	"Greater than or equal to" 384 hours per month.
4	All hours (planned availability is unrestricted)

Since 2005, standard energy contracts for in state resources have not counted towards RA and LSEs are increasingly shifting towards meeting RA obligations with resources that are not contractually limited. Other concerns remain related to physical availability of facilities due to emissions limits or intermittent production, but these issues are not addressed by the MCC bucket structure.

Table 2 provides the maximum cumulative capacity allowed for each of the buckets, the August 2016 requirements, and the aggregate August 2016 LSE capacity showing for each of the cumulative buckets. As Table 2 demonstrates, for August 2016, most LSEs procured resources that fell into Category 4. This pattern is consistent throughout the year and the data for the other months is included in the tables in Appendix A.

Table 3. Summary of Requirements and Monthly Compliance Showing for August 2016

	Maximum Cumulative Capacity Allowed	August Requirement Cumulative	August Showing (MW)	August Showing (%)
Bucket 1	16.21%	8,166	305	<1%
Buckets 1 & 2	21.71%	10,937	2,715	5.4%
Buckets 1, 2 & 3	33.76%	17,003	5,216	10.3%
Bucket 1, 2, 3, 4 & DR	n/a	50,367	50,558[3]	100%

Table 2 and the tables in Appendix A demonstrate that the MCC buckets are not binding and at this point do not serve a clear reliability purpose. Further, the Commission has adopted flexible capacity requirements for its jurisdictional LSEs and the must-offer requirements for flexible resources developed by CAISO further ameliorates concerns regarding over reliance on use limited resources. To illustrate, the flexible capacity requirement for CPUC jurisdictional LSEs exceeds 9,000 MW in all months and exceeds 14,000 MW in some months for 2017 and, to date, this flexible capacity requirement has been met largely with resources that have fewer use limitations (e.g., gas-fired generation). For these reasons, Energy Division staff proposes to eliminate the MCC bucket requirement for the 2018 compliance year.

[3] Includes 2,138 MW of DR.

Appendix A

	Maximum Cumulative Capacity Allowed	January Requirement Cumulative	January Showing (MW)	January Showing (%)
Bucket 1	16.21%	5,299	208	<1%
Buckets 1 & 2	21.71%	7,097	1,059	3.2%
Buckets 1, 2 & 3	33.76%	11,034	1,447	4.4%
Bucket 1, 2, 3, 4 & DR	n/a	32,684	33,168[4]	100%

	Maximum Cumulative Capacity Allowed	February Requirement Cumulative	February Showing (MW)	February Showing (%)
Bucket 1	16.21%	5,102	207	<1%
Buckets 1 & 2	21.71%	6,833	1,122	3.4%
Buckets 1, 2 & 3	33.76%	10,624	2,110	6.5%
Bucket 1, 2, 3, 4 & DR	n/a	31,470	32,669[5]	100%

	Maximum Cumulative Capacity Allowed	March Requirement Cumulative	March Showing (MW)	March Showing (%)
Bucket 1	16.21%	5,109	211	<1%
Buckets 1 & 2	21.71%	6,842	1,326	4.1%
Buckets 1, 2 & 3	33.76%	10,638	2,501	7.7%
Bucket 1, 2, 3, 4 & DR	n/a	31,511	32,569[6]	100%

	Maximum	April	April Showing	April Showing

[4] January - Includes 1,136 MW of DR.
[5] February - Includes 1,118 MW of DR.
[6] March - Includes 1,193 MW of DR.

	Cumulative Capacity Allowed	Requirement Cumulative	(MW)	(%)
Bucket 1	16.21%	5,294	205	<1%
Buckets 1 & 2	21.71%	7,090	1,171	3.5%
Buckets 1, 2 & 3	33.76%	11,022	1,834	5.4%
Bucket 1, 2, 3, 4 & DR	n/a	32,649	33,942[7]	100%

	Maximum Cumulative Capacity Allowed	May Requirement Cumulative	May Showing (MW)	May Showing (%)
Bucket 1	16.21%	6,009	203	<1%
Buckets 1 & 2	21.71%	8,048	1,312	3.4%
Buckets 1, 2 & 3	33.76%	12,512	2,231	5.9%
Bucket 1, 2, 3, 4 & DR	n/a	37,063	38,097[8]	100%

	Maximum Cumulative Capacity Allowed	June Requirement Cumulative	June Showing (MW)	June Showing (%)
Bucket 1	16.21%	6,904	255	<1%
Buckets 1 & 2	21.71%	9,247	2,118	4.9%
Buckets 1, 2 & 3	33.76%	14,376	3,310	7.7%
Bucket 1, 2, 3, 4 & DR	n/a	42,583	42,913[9]	100%

	Maximum Cumulative Capacity Allowed	July Requirement Cumulative	July Showing (MW)	July Showing (%)

[7] April - Includes 1,438 MW of DR.
[8] May – Includes 1,788 MW of DR.
[9] June – Includes 1,916 MW of DR.

Bucket 1	16.21%	7,731	303	<1%
Buckets 1 & 2	21.71%	10,355	2,741	5.7%
Buckets 1, 2 & 3	33.76%	16,098	5,154	10.8%
Bucket 1, 2, 3, 4 & DR	n/a	47,686	47,917[10]	100%

	Maximum Cumulative Capacity Allowed	August Requirement Cumulative	August Showing (MW)	August Showing (%)
Bucket 1	16.21%	8,166	305	<1%
Buckets 1 & 2	21.71%	10,937	2,715	5.4%
Buckets 1, 2 & 3	33.76%	17,003	5,216	10.3%
Bucket 1, 2, 3, 4 & DR	n/a	50,367	50,558[11]	100%

	Maximum Cumulative Capacity Allowed	September Requirement Cumulative	September Showing (MW)	September Showing (%)
Bucket 1	16.21%	7,386	156	<1%
Buckets 1 & 2	21.71%	9,892	2,164	4.7%
Buckets 1, 2 & 3	33.76%	15,379	4,099	8.9%
Bucket 1, 2, 3, 4 & DR	n/a	45,556	45,829[12]	100%

	Maximum Cumulative Capacity Allowed	October Requirement Cumulative	October Showing (MW)	October Showing (%)
Bucket 1	16.21%	6,136	158	<1%
Buckets 1 & 2	21.71%	8,217	1,487	3.9%

[10] July – Includes 2,054 MW of DR.
[11] August – Includes 2,138 MW of DR.
[12] September – Includes 2,068 MW of DR.

Buckets 1, 2 & 3	33.76%	12,775	2,483	6.5%
Bucket 1, 2, 3, 4 & DR	n/a	37,842	38,095[13]	100%

	Maximum Cumulative Capacity Allowed	November Requirement Cumulative	November Showing (MW)	November Showing (%)
Bucket 1	16.21%	5,380	127	<1%
Buckets 1 & 2	21.71%	7,206	811	2.3%
Buckets 1, 2 & 3	33.76%	11,203	1,676	4.8%
Bucket 1, 2, 3, 4 & DR	n/a	33,184	34,974[14]	100%

	Maximum Cumulative Capacity Allowed	December Requirement Cumulative	December Showing (MW)	December Showing (%)
Bucket 1	16.21%	5,469	101	<1%
Buckets 1 & 2	21.71%	7,324	817	2.4%
Buckets 1, 2 & 3	33.76%	11,387	1874	5.4%
Bucket 1, 2, 3, 4 & DR	n/a	33,730	34,585[15]	100%

[13] October – Includes 1,849 MW of DR.
[14] November – Includes 1,184 MW of DR.
[15] December – Includes 1,081 MW of DR.

Proposal 3: Allocation of Incremental Demand-Side Resource Procurement (Addition of an Annual and Quarterly Process)

Background

In D.15-11-041, the Commission approved Southern California Edison's (SCE's) local capacity requirement (LCR) LA Basin procurement (A.14-11-012), which included 351.77 MW of behind-the-meter (BTM) demand-side resources. These resources include distributed generation (DG), demand response, energy efficiency, and storage. The Commission considered these resources to be incremental to the existing demand side programs. The cost allocation method approved for these resources followed the existing cost allocation for other behind-the-meter resources (Public Purpose Program (PPP) surcharge and distribution surcharge).

Issue

While cost allocation mechanisms exist for these resources, no mechanism currently exists to allocate the local, system and flexible capacity ***benefits*** associated with these resources to load serving entities in the year ahead and intra-year time frames.

In order to allocate the capacity values consistent with the costs of these resources into the current resource adequacy (RA) framework, it will be necessary to establish two processes: one to allocate the system capacity benefits and another to allocate the local capacity benefits.

In D.15-11-041, the Commission approved procurement of 351.77 MW of additional demand side resources, with some capacity coming online beginning as early as January 2017. To ensure this capacity is counted towards the local and system requirements for 2017, an intra-year allocation mechanism will need to be adopted and implemented. Further, to ensure this capacity counts toward the local requirements in future years, an annual local allocation process will be necessary.

The following table summarizes the MW quantity of SCE's BTM incremental LA Basin LCR resources by their commercial operation dates (COD).

Year COD	Additional MW's Reaching COD by 6/1 of the Associated Year	Total Additional MW's Reaching COD for Associated Year	Total Cumulative MW that Count Towards Meeting LA Basin Local Requirements
2017	5.50	30.26	5.50
2018	45.23	66.00	75.49
2019	144.74	163.81	241.00
2020	25.90	45.95	285.97
2021	38.75	38.75	344.77
TBD	7.00	7.00	351.77

In response to the CAISO's 2018 Local Capacity Technical Study criteria, methodology and assumptions call, CPUC staff requested that CAISO work with the CPUC, CEC and IOUs to ensure that load forecasts are adjusted for BTM local capacity procurement. CAISO responded to staff's comments stating that:

- Procured demand-side resources that are verified by the CPUC and the CEC with the applicable LSEs for being online and available by June 1 of the study year will be modeled in the LCR study. This includes preferred resources procured under long-term procurement plan for the LA basin as verified by the CEC staff.
- The load forecast does not need adjustment to consider incremental or other demand side resources, they are to be modeled discretely at each bus.
- Demand side resources do not reduce the LCR need. They are a part of the resources used to mitigate the LCR need.[16]

Proposal

Given that these resources will not reduce the LCR need in the CAISO's local study, a mechanism needs to be developed to ensure that these resources count towards the local requirement for which they were specifically procured. Thus, staff proposes, for the year-ahead local process, to reduce the overall RA requirement in each local area by the amount of total BTM capacity in each local area (e.g. LA Basin) prior to year-ahead local RA requirements being allocated to LSEs.

To ensure that the local capacity is included in the intra-year process, staff proposes to incorporate theses resources into the local true-up mechanism (for 2017 local RA, this process would need to be adopted before the local true-up allocation is done (April 1, 2017)). For the year-ahead local process, staff proposes to reduce the overall RA requirement, in each local area, by the amount of total BTM capacity in each local area (e.g. LA Basin) prior to year-ahead local RA requirements being allocated to LSEs. It should be noted that the CAISO will also have to adopt a parallel process in its reliability requirements system (CIRA), in order to ensure there are no inconsistencies between CPUC and ISO LCR requirements when performing LSE RA validations.

In order to equitably allocate the system benefits of the behind-the-meter resources, staff proposes to allocate the benefits as part of the annual load forecast adjustment process and as part of the monthly CAM allocation process. Because there will be no matching supply plan for these demand-side resources, both IOUs and ESPs will received demand side credits (i.e., a downward adjustments to load) to account for any incremental demand side resource that will be coming online. Resources that are procured in time to be counted in the year-ahead process will be allocated through an adjustment to the year-ahead load forecast (Table 1 in the LSEs annual allocations). Resources that cannot be incorporated in the year-ahead process will be incorporated into the quarterly CAM process.

To implement this proposal, staff will modify the current month-ahead template to include an additional table that will allow LSEs to insert these demand side credits (load adjustments) into their month-ahead

[16] http://www.caiso.com/Documents/ISOResponsestoCommentsfromOct312016StakeholderCall.pdf, p. 8.

templates. The credits would lower the overall load forecast used to set monthly system RA requirements. To allocate the system RA benefits for the second half of 2017 (July-December), this process would need to be adopted before the quarter 3 CAM allocations are sent (April 1, 2017).

Proposal 4: Accounting for Existing Demand Side Impacts in the Annual Load Forecast Adjustment Process

Background

In establishing the resource adequacy (RA) framework, Phase II of R.04-04-003 outlined how energy efficiency (EE), demand response (DR), and distributed generation (DG) programs should be accounted for in the load forecast. A phase II RA workshop report addressed the quantification of EE, DR, and DG impacts and the allocation of those impacts to LSEs.

The phase II workshop process clarified that in order for the CEC to determine what level of EE, DR, and DG impacts should be used to adjust an LSE's preliminary load forecast, the LSE must document any such impacts it believes are already included in the preliminary load forecast and provide a methodological rationale supporting this understanding.[17]

D.05-10-042 concluded that for the purposes of quantifying demand side impacts that "there is a need for the three IOUs to prepare and document the hourly impacts of EE, DR and DG programs within their service areas and to provide these impacts to the CEC for use in the adjustment of LSE load forecasts.[18]

In order to quantify the impacts of the demand side resources, the Commission recognized that the CEC staff would need to work with LSEs in its review of individual LSE forecasts, and that LSEs would need to respond to the CECs requests in a timely manner. The Commission stated that this type of process would "be enhanced if, a month or more before the LSEs' respective historic and forecast load submittals are due, the CEC, in coordination with our Energy Division, issues instructions to each LSE regarding those submittals."[19]

Issue

Once a demand side resource is operational, and therefore included in an LSE historical meter data, there should be a transparent way of reporting the demand side impacts of the resource to the CEC. This should be done in order to equitably allocate any associated capacity benefits to benefiting LSEs and to adjust load prior to making an LSE specific coincident adjustment to the year-ahead load forecasts. D.05-10-042 identified this need (as noted in the background), but it has become clear that there is no consistent reporting by LSEs of demand side resource impacts to the CEC for use in the existing RA load forecast adjustment process.

Proposal

Staff proposes that by March 15th of each year, IOUs provide historical hourly demand side load impacts for DR, DG and EE to LSEs (ESPs and CCA) that serve load in the IOU's service territory. The load impacts would be associated with any historical demand side impact recorded for all the customers served by

[17] D.05-10-042, p. 84.
[18] D.05-10-042, FF 14
[19] D.05-10-042, pp. 84-85.

the associated LSE. If the program is a non IOU program, these load impacts will need to be distributed by the demand side resource provider.

The IOUs, CCAs and ESPs would include these load impacts in their year-ahead load forecast submissions to the CEC (and CPUC) in April of each year.

The IOUs would also need to provide the CEC (and CPUC) these load impacts to ensure that all LSEs are including them in their individual LSE load forecast and to ensure that the capacity benefits are allocated equitably in the CEC load forecast adjustment for demand side resources.

For the 2018 year-ahead load forecast process, it will be necessary to adopt this proposal prior to March 15th so that LSEs can include the load impacts in their historical load forecasts to the CEC on or around March 22nd, 2017.

Proposal 5: Capping Annual ELCC at Exceedance

Energy Division staff proposes that the Commission consider a simplified ELCC methodology for compliance year 2018, adopting the annual effective load carrying capacity (ELCC) values for wind and solar resources capped at monthly exceedance values, if the monthly ELCC values proposed by Energy Division staff this year are not adopted.

Per statute,[20] the CPUC is tasked with adopting an effective load carrying capacity (ELCC) value to be used in establishing the contribution of wind and solar energy resources toward meeting the resource adequacy requirements established pursuant to Section 380. In D.16-06-045, the Commission considered Energy Division staff's proposal regarding solar and wind ELCC values, but noted concern that the "dramatic increase in the capacity value of wind and solar resources in the off-peak (winter) months relative to the current exceedance values may negatively affect reliability in those months." Moreover, the decision also noted that "SCE's proposed NPR-ELCC, or similar approach may be a viable solution to this challenge and merits further consideration" or that "some simplified ELCC methods suggested by CalWEA may be appropriate."

Last year, Energy Division staff proposed annual ELCC values for wind and solar of 12.6% and 57.8%, respectively. These annual values are shown in the table below and compared to the 2017 technology factors developed using the existing exceedance methodology. As this table demonstrates, the annual ELCC values for both wind and solar are lower in the summer months (e.g., 57.8% versus 80.3% for solar in August), but higher than the technology factors in the winter months.

Table 4. Wind and Solar Exceedance and ELCC Values

	Wind		Solar	
	2017 Technology Factors	ELCC	2017 Technology Factors	ELCC
January	2.4%	12.6%	0.3%	57.8%
February	10.9%	12.6%	1.5%	57.8%
March	16.4%	12.6%	6.8%	57.8%
April	19.9%	12.6%	79.8%	57.8%
May	32.9%	12.6%	75.6%	57.8%
June	26.6%	12.6%	79.3%	57.8%
July	18.9%	12.6%	75.3%	57.8%
August	17.6%	12.6%	80.3%	57.8%
September	11.3%	12.6%	75.0%	57.8%
October	6.5%	12.6%	57.5%	57.8%
November	4.0%	12.6%	0.2%	57.8%
December	4.6%	12.6%	0.1%	57.8%

[20] California Public Utilities Code, Section 399.26 (d)

The technology factors are driven primarily by the current assessment hours. The assessment hours are focused on the peak load hours for the months/season. For April to October, the assessment hours are 1 pm to 6 pm, or times when solar resources are likely to be producing. By contrast, the current assessment for hours for the remaining months (i.e., November – March) are from 4 pm to 9 pm, or hours when solar resources produce considerably less energy.

One of the main obstacles to the adoption of ELCC appears to be that an ***annual ELCC*** is inconsistent with the California monthly RA framework. ELCC values are typically determined annually and work well if the capacity obligation is annual. However, California's RA framework is monthly (i.e., the obligation is set for each month, not for the entire year).

In a separate proposal, Energy Division staff has proposed monthly ELCC values, but we note that the monthly modeling approaches for ELCC are new, and have not been adopted or applied in any other jurisdiction, to the best of our knowledge. Therefore, if consensus is not reached on monthly ELCC values, Energy Division staff recommends that the Commission consider a hybrid approach that can move towards ELCC values, which are likely to be lower than our current capacity counting conventions, but ensure that potential reliability concerns are addressed (i.e., potential over-reliance on wind and solar resources in winter months).

To this end, Energy Division recommends that the Commission consider capping the annual ELCC value at the exceedance value, if monthly ELCC values are not adopted. This proposal is shown in the table below.

Table 5. Annual ELCC Values Capped at Exceedance

	Wind		**Solar**	
	2017 Technology Factors	**ELCC Capped at Exceedance**	**2017 Technology Factors**	**ELCC Capped at Exceedance**
January	2.4%	2.4%	0.3%	0.3%
February	10.9%	10.9%	1.5%	1.5%
March	16.4%	12.6%	6.8%	6.8%
April	19.9%	12.6%	79.8%	57.8%
May	32.9%	12.6%	75.6%	57.8%
June	26.6%	12.6%	79.3%	57.8%
July	18.9%	12.6%	75.3%	57.8%
August	17.6%	12.6%	80.3%	57.8%
September	11.3%	11.3%	75.0%	57.8%
October	6.5%	6.5%	57.5%	57.5%
November	4.0%	4.0%	0.2%	0.2%
December	4.6%	4.6%	0.1%	0.1%

The merits of this proposal are that it would allow for adoption of ELCC for a portion of the year (primarily the summer months which have the most reliability events), it would address potential reliability concerns for the winter that were raised by the parties, and it ensures that there is not an over-reliance on wind and solar in off-peak (winter) periods.

Energy Division staff notes that the CPUC-jurisdictional LSEs rely very little on wind and solar resources in winter months due to the current exceedance methodology, and reliance on these resources in the summer months is not substantial (see the yellow and blue bars in the figure below). While concerns have been raised that we may have insufficient RA resources to meet our net peak load (i.e., peaks without wind and solar resources), Energy Division staff analysis at this point does not lead to that conclusion, at least the past year, where the non-wind and non-solar resources exceeded the net peak load in all months (with the possible exception of June 2016).