Proposal for Creation of Loss of Load and Solar Effective Load Carrying Capability Values for 2018 Resource Adequacy Compliance Year

RESOURCE ADEQUACY PROCEEDING R.14-10-010
CALIFORNIA PUBLIC UTILITIES COMMISSION – ENERGY DIVISION

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Contents

I. List of Acronyms

AAEE – Additional Achievable Energy Efficiency	NQC – Net Qualifying Capacity
BAA – Balancing Authority Area	PU Code – Public Utilities Code
CAISO – California ISO	RA – Resource Adequacy
CEC – California Energy Commission	RPS – Renewable Portfolio Standard
ELCC – Effective Load Carrying Capability	SERVM – Strategic Energy Risk Valuation Model
IEPR – Integrated Energy Policy Report	TEPPC – Transmission Expansion Policy Planning Committee
LCR – Local Capacity Requirements	WECC – Western Electric Coordinating Council
LOLE – Loss of Load Expectation	

II. Summary of ELCC Proposals and Key Updates for 2018

Pursuant to PU Code 399.26(d) Energy Division staff has been working to develop an analytically sound method to calculate Effective Load Carrying Capability (ELCC) for wind and solar resources that can serve as a qualifying capacity for the Commission's Resource Adequacy (RA) program. An ELCC study is a form of reliability assessment, which seeks to quantify and measure the reliability contribution of certain generators or classes of generators to aggregate system electric reliability. Aggregate system reliability is measured by indices such as the Expected Unserved Energy or Loss of Load Expectation (LOLE) among others. Energy Division staff measure ELCC as the amount of LOLE mitigation that a class of generators provides relative to an equivalent amount of ideal or "perfect" electric generating capacity.

Loss of load is found whenever, on aggregate, electric demand exceeds the capability of the modeled generation resources to serve demand. Energy Division has released a number of proposals that demonstrate advances in Energy Division's modeling effort, as well as periodically revised and reposted the Inputs and Assumptions Paper that detailed Energy Division's overall effort to develop and maintain the data that goes into modeling. Details such as development of electric demand and generation profiles, fuel price and other generator inputs, and delineation of regions in the model are outlined in the Inputs and Assumptions paper.[1]

Via the RA proceeding (currently R.14-10-010), parties and staff have been collaboratively developing policy and analytical guidance for the execution of LOLE and ELCC studies, and the production of results. Energy Division most recently issued a proposal in March 2016[2] to create locationally specific ELCC factors for wind and solar generators, as well as a temporary method to allocate those factors to individual months of the year. Parties also commented on a number of issues, most notably that the temporary method of allocating factors to months was not supported by analysis, and that Energy Division should explicitly include the benefits of behind the meter solar facilities in the overall calculation of ELCC for solar facilities in general. The Commission ultimately chose not to adopt Energy Division's proposal, noting as it did so that a more analytically robust allocation of capacity credit to individual months was within reach and urged Energy Division to develop the proposal for adoption in the 2018 RA compliance year.

In response to these comments and Commission guidance, Energy Division pursued the development of ELCC values for wind and solar generators in each month and not just in the narrow peak periods of the year. Staff developed a methodological process which we lay out here, including updates to a number of data inputs and improvements to the underlying database since the March 2016 Energy Division proposal. With these improvements and upgrades, Energy Division offers this proposal as a bookmark to the proposal issued in March, and to illustrate the implications of two main decisions Energy Division

[1] Posted to the CPUC Website here: http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6570

[2] Revised ED Staff ELCC and LOLE proposal issued to R.14-10-010 on March 23 is linked to the CPUC website on this page: http://www.cpuc.ca.gov/General.aspx?id=6265

staff made for the current proposal in response to specific party and Commission comments. Energy Division staff attempted to model behind the meter solar as a resource in order to gauge its effect on overall solar ELCC, and thus study the overall value of all the solar generation that is projected to be online in 2018. As a point of contrast, the March 2016 Energy Division proposal produced ELCC results for a solar fleet that included a total of 7,424 MW of solar; the current solar fleet being modeled in this proposal includes 16,033 MW of solar, including over 5,500 MW of behind the meter solar.

The increase in solar generation in the model likely resulted in lower ELCC for solar resources than would have been the case otherwise and also presents policy challenges for the current RA program. While the overall effect of increased solar penetration is complicated due to shifts in the timing of peak loads and interaction with the underlying load shapes, the relative decline in value for solar generation as more of it is added is an expected and understood outcome. For that reason, parties are encouraged to consult the March 2016 Energy Division proposal as added context and as a bookmark for the effect of the addition of the solar facilities. The March 2016 RA proposal is thus an important companion to this proposal. Parties are encouraged to review the impact of these decisions in their comments.

Explicit inclusion of behind the meter solar in the calculation of solar ELCC raises important questions about the overall structure of the RA program. The current RA program requires LSEs to procure an amount of qualifying capacity (comparable to the effective capacity referenced in this proposal) that can be reasonably relied on to meet reliability conditions. RA obligations are set by adding a 15% reserve margin to the peak sales in each month, as forecasted by the California Energy Commission (CEC) via the Integrated Energy Policy Report (IEPR) study. Inclusion of behind the meter solar requires the reconstitution of consumption forecasts that add back the embedded effects of behind the meter solar to the net sales forecasts prepared by the CEC.

Were RA obligations meant to be calculated through this process, the RA obligations would be set relative to consumption forecasts, not sales, and behind the meter solar would explicitly receive RA capacity credit. Changing the calculation of the RA obligation in the manner discussed here is currently not in the scope of the RA proceeding R.14-10-010, thus is not part of this proposal. It is possible that in the future that could be scoped in pursuant to party input and consultation.

Energy Division proposes to establish month specific ELCC values that reflect the ability of all solar generators (including behind the meter solar) to mitigate LOLE, as a ratio of the nameplate capacity of Perfect Capacity added to the system to provide equal LOLE mitigation as the solar facilities that were removed. This analysis is done on a month specific basis, and thus represents a monthly ELCC calculation.

ELCC for the 16,033 MW of solar resources that are expected to be generating in 2018 (including 5,526 MW of behind the meter PV) ranges from about 1% in December to about 30% in June and July.

Energy Division presents these data updates and software upgrades, along with these proposed modeling results for study year 2018, and proposes to adopt these changes for the 2018 RA compliance year.

A. Key Data Updates

Energy Division staff performed several important data updates since March of 2016. Staff downloaded and migrated to the latest version of the 2026 TEPPC Common Case (v1.5). Since staff did not use the load, wind, or solar profiles from TEPPC, staff was confident that the listing of generators and the forecasts of load for each area in v1.5 of the 2026 Common Case were sufficient. Staff disaggregated the areas external to California from ten different states to seventeen different balancing authority areas (BAA). Finally, staff authorized Astrape Consulting to restudy and redevelop all load, solar, wind, and hydro shapes to incorporate actual historical data from more recent years, to map weather and load to the new utility service areas, and to correct the mapping of hydroelectric facilities within California.

In general, there was good conformance between the 2024 Common Case and the 2026 Common Case. Unlike previous years, where there were significant and very labor intensive changes to make, this time the needed updates were very minimal. Out of roughly 3,200 generators outside of the CAISO that are in the 2026 TEPPC Common Case, only around 200 did not match what was already in the SERVM dataset from the 2024 Common Case dataset. Staff matched most of the facilities between the Common Case and the SERVM dataset with the exception of hydroelectric facilities. Since staff model hydroelectric generation with aggregated units to incorporate all of the historical hydro generation from the various areas, individual hydroelectric units do not need to be included in the dataset.

There were also six large planned generating facilities that were included in the 2024 Common Case to be built in the future, but have since been canceled, and thus were not included in the 2026 Common Case. Staff ensured that the maximum and minimum operating levels (capmax and capmin) as well as the fuel inputs and heat rates for each generator in the SERVM dataset agreed with the 2026 Common Case. Units were also placed in the correct balancing authority area. This step was easier than it had been previously due to the realignment of areas in WECC to match the utility service areas rather than states.

Staff updated the wind, solar, and hydro profiles to add recent weather and performance data from 2013 and 2014 to the pool of available historical data. Astrape then used the recent data to create predictor relationships and new hourly profiles. Hydroelectric generation data was recreated to correct unit mapping between areas in California. In addition, recent drought conditions have resulted in lower predicted hydroelectric generation for recent weather years. Hydro, wind, and solar shapes now represent 35 years of weather history, from 1980 through 2014.

Hourly behind the meter solar impacts are explicitly modeled from these installed capacities using historical hourly weather data and a technology factor appropriate for behind the meter solar. The technology factor provides the relationship between insolation and generation.

The most recent five years of historical load and weather are used to train a neural network model, developing a relationship between weather and load. The historical data is corrected for demand response and behind the meter photovoltaic effects. This relationship between weather and load is then used to develop hourly load curves for all 35 historical weather years in the CPUC dataset, which are then scaled to the appropriate peak and annual average forecasts as defined by the CEC IEPR consumption forecast described above.

Staff made several updates to reflect expected generation retirements between now and 2018, and added in the latest RPS portfolios resulting from the RPS calculator.[3] About 5,183 MW of RPS wind and solar facilities reached commercial operation and became part of the CPUC dataset since the March 2016 study results were posted, including 3,083 MW of expected RPS solar projects and 2,100 MW of expected RPS wind projects.

1. Updated Load Forecasts – Consumption versus Sales

Energy Division staff updated peak and total energy forecasts based on the CEC 2015 IEPR load forecast for 2016 through 2026.[4,5] The CEC forecast provides estimates of peak and annual average sales, while our approach requires use of a consumption forecast due to the explicit modeling of behind the meter solar. Table 1 defines the difference between consumption and sales as used in this document. Sales are equal to consumption less behind the meter self-generation. Energy Division staff explicitly calculated hourly behind the meter self-generation – as the sum of behind the meter solar self-generation and additional achievable energy efficiency (AAEE) – and for that reason required a forecast of the total demand forecast in terms of consumption, not sales. In order to adjust the CEC sales forecast back to a forecast of consumption, Energy Division staff added back the exact same forecast peak and annual average behind the meter solar generation modeled in the CEC forecast.

[3] The current RPS calculator is linked to the CPUC website here: http://www.cpuc.ca.gov/RPS_Calculator/

[4] CEC IEPR 205 Forms 1.2 and 1.4

[5] CEC IEPR 2015 Forms 1.5a and b

Table 1 Definition of Terms - Energy Demand

Load Types	Relation to Other Terms	Rationale	Measurement
Consumption	Sum of electrical energy used to operate end-use devices excluding charge/discharge of storage	Consumption is the term used in CEC Forms to capture onsite energy usage.	With increased self generation, and when relying on net energy metering to apply cost responsibility to end-users, consumption becomes counterfactual.
Sales	Consumption less behind the meter onsite generation including storage charge/discharge and less AAEE	Sales is the energy term to indicate the net energy delivered through the meter to the end-use customer	Metered by the utility on a short interval basis if the utility has deployed interval metering systems for end-users; otherwise could be estimated using load research practices
System	Sales load plus transmission and distribution losses plus theft and unaccounted for energy	Standard electricity industry term. CEC defines "hourly system load" in its data collection regulations	Generally measured by power plant output and import flows, e.g. a top down measurement inferring loads rather than a bottom up summation of individual customer loads
Net Load	System load less intermittent renewable generation	This is the same definition as being used by CAISO	BAA estimation of system load less measured output of wind and solar supply-side renewables

Table 1: Load type definitions. Note that for the CPUC production cost modeling work we are modeling behavior at the system level, and we do not differentiate between sales and system load. Said another way, we gross sales to the system level, accounting for distribution level losses.

Embedded in CEC Forms 1.5a and 1.5b is an estimate of the peak and average annual behind the meter solar self-generation. Energy Division staff extracted this almost identical value[6] using an ancillary CEC calculation and added the original peak and annual average behind the meter solar generation back to the CEC calculation resulting in a forecast for consumption only. One benefit of this approach is that propagation of error is minimized because staff added back an almost identical value as was originally subtracted from the consumption. We then use the same behind the meter solar capacities used in the original CEC calculation as the basis for our behind the meter solar installed capacity by TAC and by year through 2026, consistent with forecasts of behind the meter solar penetration. 5,526 MW of behind the meter solar were modeled as being available in 2018.

B. *Updated Regions and New Weather Data*

Weather is an integral input into probabilistic reliability modeling. It is used both in the development of synthetic load shapes, which are highly correlated to temperature, and in the development of generation profiles for weather-sensitive resources such as wind and solar. In order to balance the need to model the diversity of weather across the state and the need to keep modeling times feasible, a set of representative weather stations are selected and grouped to create regions that are modeled as

[6] Because of small differences between how the CPUC and CEC approaches define service areas, there may be very small discrepancies due to slight misalignment in geographical mapping.

homogeneous areas. This section details the weather data utilized, the sources for this data, the regions modeled, and the process by which these regions were created.

SERVM models eight distinct regions within California and seventeen outside of California. This represents a significant increase in granularity and complexity (total of 25 areas versus 18) over the work Energy Division staff performed during 2015. These regions are utilized throughout SERVM to associate groups of generation facilities with common weather, load, weather-related generation profiles, transmission constraints, and utility service territories. The regions modeled are listed in Table 2, below. The regions below do not correspond to Local Areas, and are not granular enough for transmission planning. In the future, higher granularity could be achieved by splitting the regions into smaller areas. That is not currently the purpose of Energy Division staff's efforts.

Table 2. Regions Modeled in SERVM

California Regions	**Regions external to California**	
IID (Imperial Irrigation District) BAA	Arizona Public Services including Gila River	Portland General Electric
		Western Area Power Lower Colorado
Los Angeles Department of Water and Power BAA	BC Hydro and Alberta Electric System Operator	Tucson Electric Power Company
PG&E Bay Area *(Greater Bay Area Local Capacity Requirements Area)*	Public Service Company of Colorado	Western Area Power Colorado and Missouri
PG&E Valley *(Non-Bay PG&E Service Territory)*	Comission Federal de Electricidad (Mexico)	Pacificorp East
SCE Service Area	Northwestern Energy Montana with Naturener and Western Area Power Montana	Bonneville Power including Puget Sound and City of Tacoma
SDG&E Service Territory	Nevada Power Company	Idaho Power Company
Balancing Authority of Northern California (aka SMUD)	Public Service Company of New Mexico and El Paso Electric Co.	Sierra Pacific Power Company
TID (Turlock Irrigation District)	Pacificorp West BAA	Salt River Project

Energy Division staff delineated regions in SERVM to correspond to both the TEPPC 2026 Common Case, and the CAISO modeling dataset. Energy Division staff no longer delineates areas by state boundaries and now delineates by BAA; for example, New Mexico, Idaho, and Utah will be represented instead by Public Service New Mexico, Idaho Power Company, and Pacificorp East respectively. Load shapes and wind/solar/hydro production profiles were created accordingly. Please consult the Energy Division Inputs and Assumptions document for a more detailed description of the study areas and a map illustrating their location.

C. General Order of Studies in ELCC Modeling

A sequence of studies is performed to establish the LOLE of a given system and the Effective Load Carrying Capability (ELCC) of a particular resource or set of resources within a larger electric system. The calibration and sequence of these studies depends on the objectives of the study. Energy Division staff begins by taking the "as found" system, which has an unknown reliability level. In order to establish the LOLE of a system, generation is removed or added and the system is simulated iteratively until the desired reliability level is reached. If the study is attempting to ascertain reliability on a month specific level, generation is added or subtracted to each month to reach the desired reliability level. In addition to facilities that have already retired prior to the start of 2017 RA compliance year, Energy Division staff retired further generation in order to achieve the desired LOLE. In particular, generation in northern California (in PGE_Valley area specifically) was retired in order to balance the LOLE across regions of the CAISO system. Moss Landing units 6 and 7 as well as the Diablo Canyon Nuclear Power Plant were removed to reduce energy trapped in PGE_Valley by transmission constraints.

Once the CAISO system has been calibrated to the desired LOLE, it is possible to begin the ELCC studies. Energy Division staff began by removing all solar facilities in CAISO, including solar thermal and both fixed and tracking PV, and performed studies to gauge the average ELCC of all solar facilities within CAISO. All solar facilities were added and removed as a group, without distinction to location or technology. This was done to determine the portfolio ELCC of solar generators. The portfolio ELCC of each type of generator across CAISO would later be used to allocate a diversity benefit to a specific technology class or a specific locational group of facilities when the ELCC of solar facilities are calculated in more granular way.

In summary, average annual portfolio ELCC for all solar facilities in CAISO can be calculated by following these steps:

1. Study the entire study year with projected loads and expected resources. However, resources must be added or subtracted until the results equal a probability weighted average LOLE of the desired result across all twelve months of the year. Save all required output reports.
2. Selectively add or remove facilities in each individual month only until the resulting probability weighted average loss of load in each month equals the desired metric. Save all required output reports.
3. Remove all facilities under study (either a class of generators or a set of generators in a particular location depending on the type of study) but not those outside of CAISO. Add or remove "Perfect Capacity" in each individual month until the probability weighted LOLE in each individual month equals the desired level. Save all required reports
4. Once LOLE equals the desired level, find ELCC by calculating a ratio of nameplate MW removed to "Perfect Capacity" nameplate MW added, and the result is the average ELCC of the CAISO portfolio of all the studied facilities. The resulting annual ELCC value will be a percentage less than 1.
5. Once annual average ELCC values are established, calculating regional or technology specific ELCC is a second process. Similar quantities of resources are removed from each area and the ELCC of each individual area is calculated. Similar quantities are tested to measure just the locational effect, not the effect of declining ELCC due to penetration.

D. Proposed Process for Calculating Monthly LOLE and ELCC

Before the development of today's advanced computing, planners calculated probability of LOLE in the peak hour of each day, and only on weekdays. That means calculating about 260 data points in total. Today's computers perform simulations, not simple calculations, and perform simulations of each hour of the year thousands of times with multiple stochastic variables. Thus, a LOLE metric of 0.1 which is conveniently referred to as one day in ten years that arose out of previous generations of simple calculations may no longer be appropriate given the expanded scope of hourly simulations with more advanced computers.

Energy Division staff is assessing each month individually to determine the adequate level of effective capacity to maintain reliability in each individual month. This runs counter to the traditional means of performing LOLE studies in which sufficient effective capacity is made available for the peak months and held year round, and that does not release surplus capacity in off-peak months. In light of this, 0.1 LOLE no longer appears to be the appropriate target. A target that represents a tolerable level of reliability stress in each individual month is more appropriate, and may total greater than a probability weighted average of 0.1 LOLE. Key questions include the definition of the appropriate level of LOLE in each month, and whether each month is to be treated equally. It may be more appropriate to set LOLE targets for peak months at higher levels than off-peak months. There is no standard approach or industry accepted metric for a month specific LOLE target, so Energy Division staff presented options to highlight the impact of different policy decisions, and to promote consideration from parties.

Staff held a workshop on November 8th, 2016 where staff presented two alternative approaches to month specific LOLE targets. First, Energy Division staff maintained the focus on peak months, with effective capacity levels adjusted in the five peak months of the year (June through October) until the results produced a probability weighted average LOLE totaling 0.1, and reduced effective capacity in the off-peak months until deminimus LOLE was encountered. The resulting effective capacity margins in each month that maintained a distribution of LOLE sufficient to total 0.1 in the summer and deminimus levels in the off-peak months will then represent the desired target capacity procurement target for each month.

Second, staff presented the results of an attempt to levelize the LOLE resulting in each month across the year. Effective capacity was added or subtracted in each month until there was roughly equal LOLE (between 0.015 LOLE and 0.02 LOLE) in each month, such that the probability weighted average total LOLE of the year totals around 0.24 LOLE. This proposal represented the situation where since the five peak months were allowed to tolerate LOLE totaling 0.1, that same treatment would be applied to all months, and all twelve months could tolerate approximately the same LOLE as the peak months.

Energy Division proposes that reliability in terms of expected LOLE should be calibrated individually for each month and that the quantity of effective capacity available for dispatch in the study runs should vary by month. Energy Division also proposes to raise the annual expected total LOLE to reflect expected LOLE in off-peak months. We propose that it is overly conservative to maintain a probability weighted average LOLE of 0.1 across the whole year, given the attempt to surface LOLE in off-peak months. Instead it is reasonable to tolerate the same risk in each month, as that is usually a good indicator of how the system ought to be operated. It is appropriate to tolerate the same risk in the winter as that seen in the summer and, in fact, the current RA program is designed along this same premise, with a static reserve margin requirement over month-specific peak loads that currently results in varying levels of capacity procurement each month.

Since the workshop, Energy Division staff has reviewed the LOLE studies they have performed, and have elected to use the midpoint of the LOLE seen in the peak months of their annual studies as the appropriate monthly target. Energy Division staff proposes to set the capacity requirements at a level sufficient to maintain a probability weighted average between 0.02 and 0.03 each month. Energy Division staff conducted a study to determine capacity required to maintain that level of LOLE in each month, removing conventional capacity (but not renewable or demand response capacity) to calibrate the capacity operating in the study. Results are displayed below.

III. Results of Modeling

Energy Division staff completed a study of the capacity required to maintain LOLE at a probability weighted average between 0.02 and 0.03 LOLE in each month of the year by iteratively adjusting capacity margins in each month. Each of the 175 cases modeled (representing a weather year matched with a load forecast error percentage) is weighted individually and impacts the weighted average LOLE resulting from that case. Table 3 below illustrates that although Energy Division staff in most months succeeded in keeping LOLE in the desired range, there were exceptions when it was difficult to calibrate LOLE levels to a greater precision. Staff adjusted capacity levels by taking out or adding actual real (not Perfect) conventional capacity to each month in order to calibrate each month's probability weighted average LOLE to the desired range. With the effort to levelize the risk of reliability problems as measured by LOLE across all months of the year, the range modeled would translate to a probability weighted total annual LOLE between 0.24 and 0.36, which is about three times the otherwise traditional metric of 0.1.

Table 3 LOLE Levels by Region and by Month

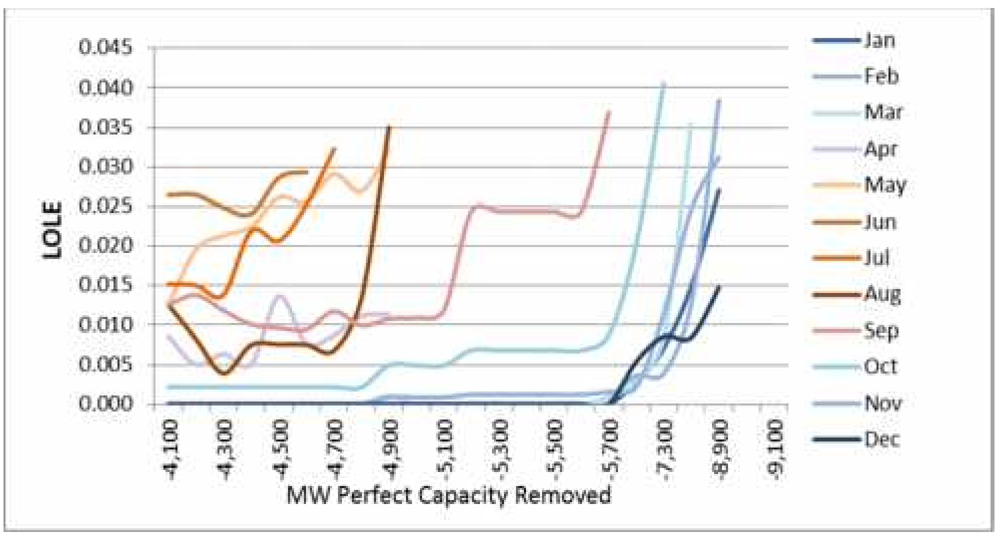
Study	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CAISO	0.0180	0.0217	0.0247	0.0223	0.0287	0.0271	0.0327	0.0260	0.0345	0.0254	0.0167	0.0194
PGE_Bay	0.0179	0.0214	0.0247	0.0094	0.0283	0.0270	0.0327	0.0260	0.0345	0.0254	0.0164	0.0188
PGE_Valle	0.0179	0.0214	0.0247	0.0094	0.0283	0.0270	0.0327	0.0260	0.0345	0.0254	0.0164	0.0188
SCE	0.0180	0.0217	0.0247	0.0223	0.0287	0.0260	0.0093	0.0249	0.0345	0.0254	0.0167	0.0194
SDGE	0.0180	0.0217	0.0247	0.0223	0.0287	0.0260	0.0093	0.0249	0.0345	0.0254	0.0167	0.0194

Due to the inclusion of 5,526 MW of behind the meter solar in the study and the reconstitution of consumption forecasts from sales forecasts and behind the meter solar generation, this approach is not easy to reconcile with the existing RA framework. Currently RA obligations are set relative to the CEC's short term weather normalized forecast of electric *sales* and behind the meter solar generation is not explicitly given RA credit. For that reason, it is not equivalent to compare the level of effective capacity needed (including behind the meter solar) to an adjusted forecast of *consumption* to generate a reserve margin similar to the existing RA obligation framework.

A. Month Specific ELCC for Solar Resources

Energy Division staff took the set of resources and loads that resulted from the monthly LOLE study process discussed previously and performed an ELCC study of solar generation in CAISO. Energy Division staff began by removing all 16,033 MW of solar facilities that delivered to CAISO (including 5,526 MW of behind the meter solar) and added in Perfect Capacity sufficient to return the system to the correct LOLE assuming the ELCC of solar generators was 57.75% (the result from the March 2016 proposal). In other words, Energy Division added too much Perfect Capacity then removed it in increments until LOLE in each month began to surface and equal the desired metrics. Energy Division staff added 9,800 MW of Perfect Capacity (about 60% of 16,033) proportionate to the location of the solar facilities deselected. Then, Energy Division staff removed increments (beginning with large 800 MW blocks) of Perfect Capacity until LOLE became close to desired levels in each month. Then Energy Division staff focused in on LOLE and began to remove 100 MW increments to be more precise. Figure 1 illustrates the progression of removing Perfect Capacity from each month until LOLE in that month reaches the desired level. The blue group of curves represent off-peak months while the peak months are grouped into red or orange curves. September and October fall in between peak and off-peak ranges of values and are in the center of the chart. Since all study areas were roughly equivalent in LOLE, attention was paid simply to replacing with Perfect Capacity in proportion to where the solar generators were located.

Figure 1 LOLE as a Function of Removing Perfect Capacity by Month



Energy Division staff added or subtracted Perfect Capacity from the study case until the average LOLE resulting from each individual month equaled the average monthly LOLE from the original monthly LOLE study that formed the baseline of the study. Figure 2 illustrates the resulting LOLE levels in each month compared to the results of the monthly LOLE study Energy Division staff performed to set the baseline.

Figure 2 Comparison of Monthly LOLE Baseline to Solar ELCC LOLE Results

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Monthly LOLE	0.0180	0.0217	0.0247	0.0223	0.0287	0.0271	0.0327	0.0260	0.0345	0.0254	0.0167	0.0194
Solar ELCC LOLE	0.0171	0.0233	0.0263	0.0245	0.0281	0.0337	0.0343	0.0246	0.0117	0.0226	0.0198	0.0206

Figure 3 illustrates the trend in ELCC for solar generators in the peak months of the year as solar penetration increases. Each line represents one month of the year, and the amount of LOLE measured in that month as Perfect Capacity was removed. For each month, the LOLE results began to rise sharply when LOLE began to be noticed, and arrived at the target range quickly. The off-peak months were able to safely absorb a greater loss of Perfect Capacity than the months around peak, with the lowest ELCC values observed for January and December, which also saw the lowest peak load levels of the year. Interestingly the highest ELCC values were for June and July. Energy Division staff's current proposal is for an ELCC of solar over peak months of 29.9% relative to Perfect Capacity, which is equal to the ELCC of solar generators in June and July. Energy Division staff's proposed Monthly ELCC values are contrasted with the current 2017 Solar PV technology factors in

Figure 4.

Figure 3 Decrease in ELCC Ratio of Solar to Perfect Capacity as Solar Capacity Increases

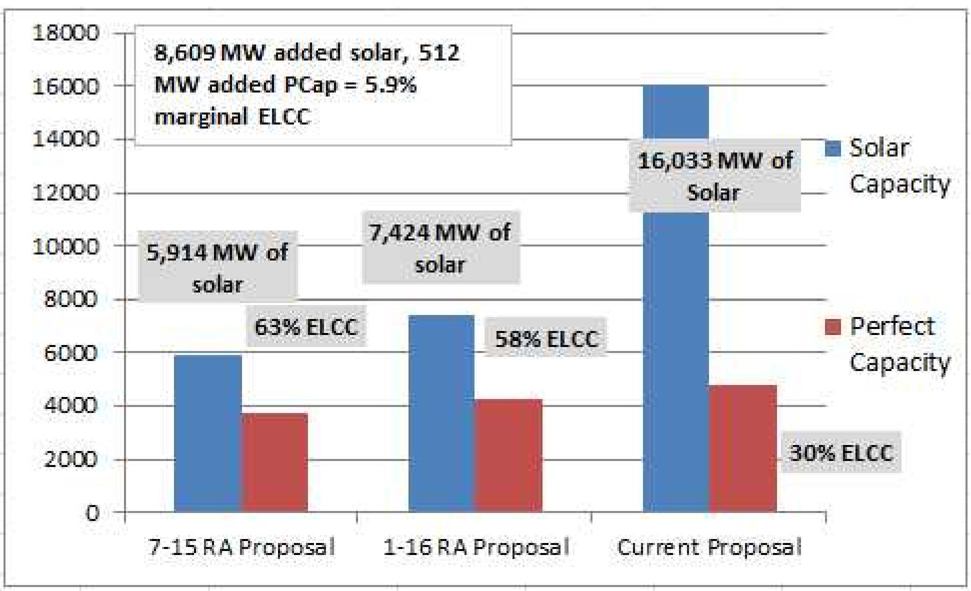
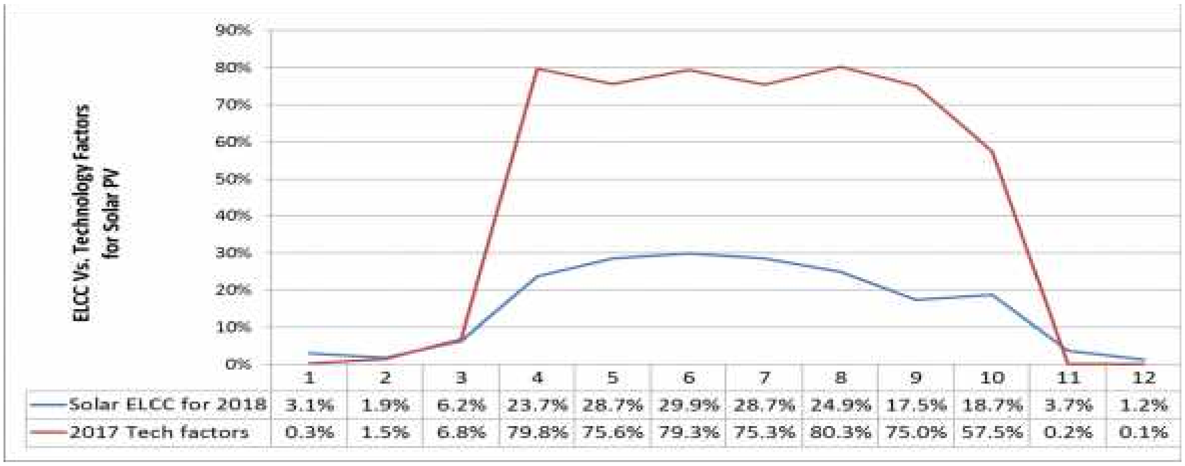


Figure 4 Decline in Value of Solar From 2017 Exceedence Method to Proposed 2018 ELCC Method



	1	2	3	4	5	6	7	8	9	10	11	12
Solar ELCC for 2018	3.1%	1.9%	6.2%	23.7%	28.7%	29.9%	28.7%	24.9%	17.5%	18.7%	3.7%	1.2%
2017 Tech factors	0.3%	1.5%	6.8%	79.8%	75.6%	79.3%	75.3%	80.3%	75.0%	57.5%	0.2%	0.1%

B. Month Specific ELCC for Wind Resources

Energy Division staff has not yet completed the modeling of month specific values for wind facilities. Energy Division will issue a proposal for month specific wind ELCC values immediately upon completion, but no later than February 24th, for 2018 RA compliance year, and to be considered in this current RA proceeding.

C. Proposed Implementation and Timeline for ELCC Values

Energy Division proposes to use the ELCC factors calculated by staff to establish the qualifying capacity of solar generators starting in 2018. The ELCC values calculated will be multiplied by the nameplate capacity of each solar generator individually, and the resulting month-specific value will equal the qualifying capacity of the generator. Although the ELCC for all solar generators as a group was calculated while including 5,526 MW of behind the meter solar, only the supply side solar is given a qualifying capacity to count towards RA obligations. Energy Division does not propose to give behind the meter solar any qualifying capacity towards RA obligations. Energy Division proposes to forgo the locational factors calculated in the March 2016 RA proposal or the technology factors proposed in earlier RA proposals.

Parties are encouraged to see this proposal as connected to Energy Division's RA proposal from March 2016. To contrast the effect of including behind the meter solar in the ELCC calculations, parties are encouraged to compare the earlier calculated value of 57.75% with this current value of 29.9% and note that of the 8,609 MW of solar added to the CAISO since March, 5,526 MW of it was behind the meter solar and only 3,083 MW of it came from incremental RPS facilities that either came online or are projected to come online between now and 2018. The ELCC values calculated also reflect the change in reliability value when load levels reflect sales (and likely reflect sales net of behind the meter solar) rather than when load levels reflect consumption, which is much higher, and reflective of load that is currently met before it ever reaches the CAISO transmission network.

Table 4 summarizes the proposed ELCC values for solar facilities for 2018 RA compliance year.

Table 4 Proposed ELCC Values for Solar and Wind

	Solar ELCC	Wind ELCC
Jan	3.1%	TBD
Feb	1.9%	
Mar	6.2%	
Apr	23.7%	
May	28.7%	
Jun	29.9%	
Jul	28.7%	
Aug	24.9%	
Sep	17.5%	
Oct	18.7%	
Nov	3.7%	
Dec	1.2%	