STATE OF NEW YORK

PUBLIC SERVICE COMMISSION

In the Matter of the Value of Distributed Energy Resources.	Case 15-E-0751
In the Matter of the Value of Distributed Energy Resources Working Group Regarding Value Stack	Matter 17-01276

Clean Energy Parties: Solar Energy Industries Association, Coalition for Community Solar Access, Natural Resources Defense Council, New York Solar Energy Industries Association, Pace Energy and Climate Center, and Vote Solar

Comments on Whitepaper Regarding Capacity Value Compensation

Dated: February 25, 2019

Comments to New York State Department of Public Service

Staff Capacity Whitepaper Comments

Case 15-E-0751

February 25, 2019

I. INTRODUCTION

On December 14, 2018 the New York Department of Public Service released its *Whitepaper Regarding Capacity Value Compensation.* The Clean Energy Parties (CEP) appreciate the opportunity to provide comments on the proposed changes to the generation capacity element of the Value Stack, which seeks to reflect the value that a distributed generator provides by offsetting purchases of installed capacity (ICAP) from the wholesale market.

II. COMMMENTS REGARDING GENERAL APPROACH

A. Alternative 1 General Approach

The original design of ICAP Alternative 1 was based on the load shape for the service class most similar to a solar generation load shape. Alternative 1 seeks to spread the class's $/kW capacity charge over a project's annual generation in the form of a $/kWh compensation rate. However, as recognized in Staff's proposal, there are numerous issues associated with this original method, including variation in whether the class's ICAP purchases were hedged or not, and inconsistencies across the utilities.

Thus, Staff proposes to base compensation on the "likely ICAP contribution from the "fleet" of distributed intermittent generation in an ICAP region."[1] To do so, Staff estimates the average generation from a solar PV system in different areas of the state and their generation during peak load hours. The generation that a system produces during the summer peak hours relative to its nameplate capacity provides the "ICAP tag" value, which then determines the proportion of the ICAP price that generators receive.

Staff's proposal is intuitive and theoretically sound. For these reasons, CEP supports the general structure of the proposed Alternative 1 compensation methodology. However, as described below, we have concerns regarding several details related to the definition of peak hours and the calculation of the ICAP tag. We also have concerns about avoidable reliability-related capacity costs that appear to have been excluded from the proposed approach, which has the potential to significantly undervalue DERs under the new approach.

B. Alternative 2 General Approach

Alternative 2 follows a similar approach as Alternative 1. First, the $/kW-year value would be determined using the ICAP tag method described above, but instead of dividing compensation over all kilowatt-hours generated, compensation would only be provided during the peak hours of the summer. In contrast to the current definition of 460 peak hours (2 pm – 7 pm, June through August), Staff proposes to limit the peak hours to between 1 PM and 6 PM on non-holiday weekdays from June 24th to

[1] Staff Capacity Whitepaper, p. 5

August 31st. For reasons described below, CEP has concerns regarding this shift in peak period definition.

III. PEAK PERIOD DEFINITION

A. Peak Days

Staff proposes to base the ICAP tag on generation during the peak summer hours between 1 PM and 6 PM on non-holiday weekdays from June 24th to August 31st. As noted in our Comments on Whitepaper Regarding Future Value Stack Compensation Including Avoided Distribution Costs,[2] these dates appear overly restrictive. Two of the past 15 peak days have occurred in early June (both in 2004 and 2008), and one of the peaks in the last 5 years occurred in September. Therefore, we recommend extending the performance period at least to June 1. This would also be consistent with NYISO's definition of the summer peak period.

B. ICAP Critical Hours

Staff proposes that the ICAP tag and Alternative 2 compensation would be tied to the top 240 – 245 hours each summer (again from June 24 – August 31 during the hours of 1 pm to 6 pm). Although we understand and support the concept behind Staff's approach for Alternative 2, we are concerned that the proposal, if not modified as we discuss below, could significantly weaken the economic justification for installing trackers and energy storage on solar PV systems under VDER.

Under the previous 460-hour methodology, the tariff created a meaningful incentive to design new DERs to target generation toward the later hours of the day. Because of the emphasis of the 460-hour methodology on the later hours of the day, this element of the tariff provided a significant incentive to construct PV systems and paired PV + storage systems designed to generate more in the latter part of the day.

However, as the table below demonstrates, the potential value of using energy storage to increase PV production during the eligible ICAP Alternative 2 hours would fall significantly under the 245-hour methodology. The reduction in potential value is less when using staff's alternative 460-hour approach.

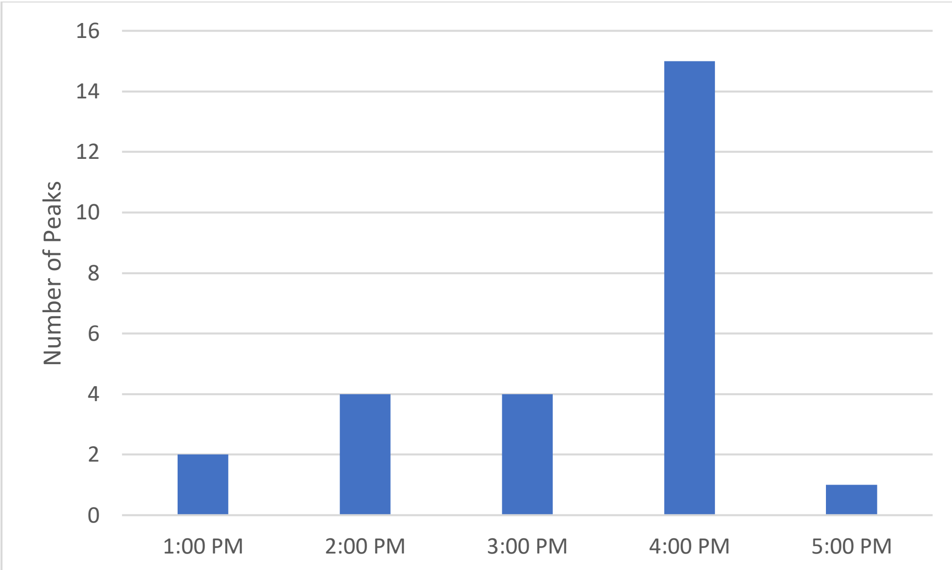
[2] CEP's Avoided Distribution Cost comments are being filed concurrently with the Capacity Whitepaper comments in Case 15-E-0751.

	PV+Storage, percent change in max value from Old (Proposed 245)	PV+Storage, percent change in max from Old (Proposed 460)
CE NYC	-52%	-28%
CE Westchester	-42%	-15%
OR	-33%	-3%
CHGE	-30%	2%
NYSEG LHV	-40%	-13%
NYSEG Upstate	-19%	14%
NMPC	-30%	-2%
RGE	-18%	14%

This reduction in potential value for paired PV+storage systems under the 245-hour approach is due primarily to the shift forward in eligible hours (i.e., moving from 2-7 PM to 1-6 PM), and to the compression of those hours into fewer days of eligible production. It is also due to the change from a customer-rate benchmark—which includes the utilities' full avoidable costs, including reliability reserve margins—to a benchmark based only on the ICAP market clearing price. This issue is discussed further below.

However, if adopted, the change to the ICAP Alternative 2 methodology would mean that more expensive tracking or PV+storage systems would not significantly outperform traditional fixed-tilt system during the eligible hours, thus reducing the benefit of these more expensive technologies. In other words, shifting from the prior 460-hour methodology to the proposed 245-hour methodology would (perhaps unintentionally) reduce the added value that trackers, west-facing designs, and paired energy storage could bring to a typical VDER project. The effect of this reduction would be that far fewer tracker and paired PV+storage projects would be deployed under VDER.

In addition to the data discussed for the DRV distribution peak hours, data on the NYISO peaks over the last 15 years provides a better justification for a 2 to 7 pm peak than a 1 to 6 pm peak. The figure below shows that the peaks tend to occur in the late afternoon, particularly 4 pm.



Further, the peak load data itself appears to show a trend toward the later hours of the day over the last ten years. For example, 7 out of 10 of the peak hours from 2009 to 2018 were in hour 16 (4-5 PM) or later. Analysis of the peak hour data shows that the most common value (mode) across both the last 10 years and the last 26 years was the hour beginning 16 (i.e., 4-5 PM). Hour 16 was also the mid-point (median) value observed across both the last 10 and last 26 years. Given that the standard deviation for the data set used by Staff is approximately 1, the first hour in Staff's proposed 245 hour-set (1-2 PM) would be three standard deviations in distance from the mid-point of 4-5 PM, whereas the proposed last hour (5-6 PM) would only be one standard deviation from the mid-point. Given the trend toward later peaking hours, it appears more reasonable to adopt a range of hours that is a consistent distance from the observed mid-point of 4-5 PM (for example 2 standard deviations plus or minus). In other words, a range of 2-7 PM appears slightly more consistent with the data than does staff's proposed range of 1-6 PM and would be more likely to encourage DERs to generate during these more accurate peak hours.

Given this analysis, we believe it is equally reasonable for staff to maintain the June 1 - August 31 and 2-7 PM peak period. Maintaining this window for both ICAP Alternative 2 and the DRV will also have the added benefit of providing a stronger signal for the construction of later-peaking PV facilities (including facilities paired with storage). We recommend that Staff either retain this period for the ICAP and DRV going forward or allow customers systems to opt between the 245 and 460-hour methodologies.

C. Grandfathering of Mature Projects Under Previous Methodology

Given the significant impact of the change in methodology on projects that are already in advanced stages of design and construction (including some that may already be constructed), we strongly recommend that the Commission allow any project that made its 25% interconnection payment prior to the issuance of the Capacity white paper (i.e., prior to December 12) to remain on the old methodology for ICAP Alternative 2. Failing to do so would create significant hardship for a number of projects and would undermine investors' confidence in New York's DER market at a crucial time for the state's clean energy goals. Specifically, we recommend that the Commission allow legacy projects to remain on the rate class and 460-hour-window that were in effect when such projects made their 25% interconnection payments.

D. Allow ICAP Alternative 2 Credits to be Allocated Evenly Throughout the Year

As with DRV credits, the CEP recommend allowing customers to apply credits received under ICAP Alternative 2 evenly across the year. The rationale for allowing such allocation across the year is the same as for DRV credits and provides for an overall better customer experience.

IV. ICAP TAG CALCULATION

The Staff whitepaper bases its ICAP tag calculations on solar generation profiles provided by NYSERDA in its Value Stack Calculator. CEP member data from its installations in the field, as well as data from NREL's PV Watts calculator show these values to be 40% to 50% too low, due solely to the fact that the solar generation profiles are not adjusted for daylight savings time (DST). The corrected ICAP tag values are shown in the table below.

Table 1. Staff ICAP Tag Values vs Daylight Savings Time Corrected Values

	NYCA	G-J	NYC
Staff Whitepaper	0.2940	0.2798	0.2908
DST Correction	0.4175	0.4084	0.4290

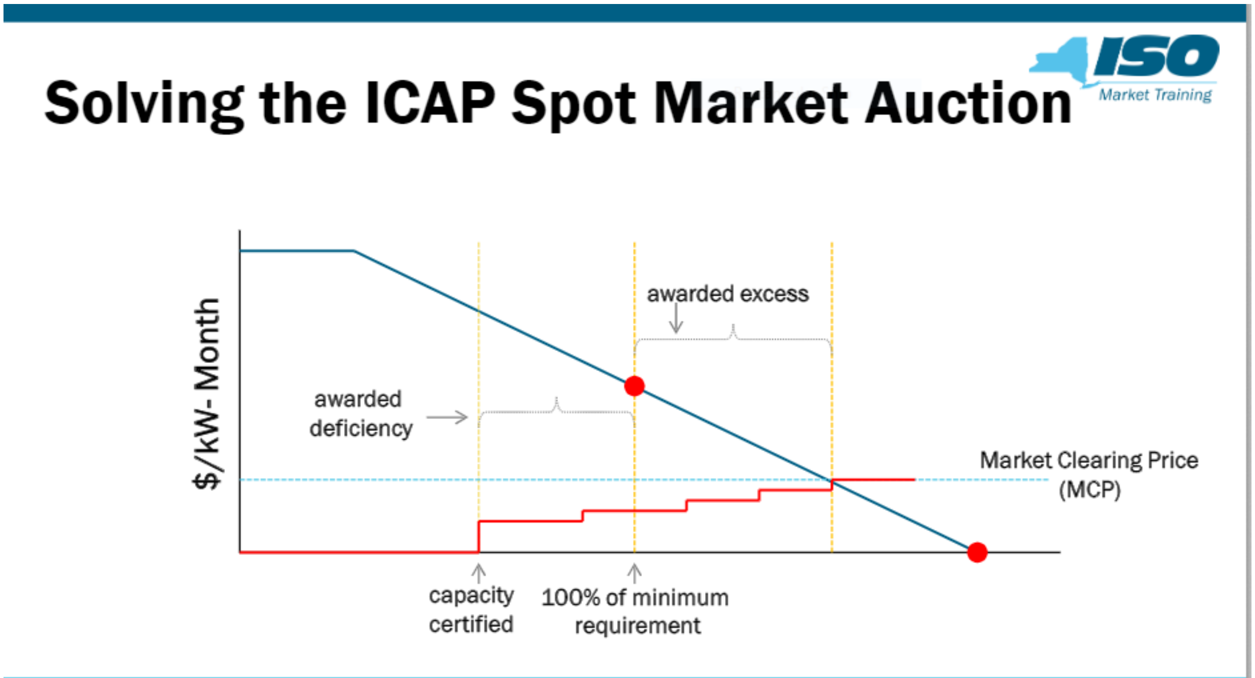
Adjusting both for DST and the peak period to weekdays June 1 – August 31, 2 pm – 7 pm yields ICAP tag values between the above values. These are shown in the table below. CEP proposes that these values be adopted.

Table 2. ICAP Tag Values Adjusted for DST and Peak Period

	NYCA	G-J	NYC
DST, 2-7 pm, 6/1 - 8/31	0.3439	0.3352	0.3442

V. ACCOUNTING FOR ALL CAPACITY PROCURED

Staff's proposal rightly accounts for several nuances in capacity procured through the wholesale market, including the Locational Capacity Requirement and adjusting for losses. However, market participants may also procure additional capacity if capacity prices are relatively low, due to the slope of the demand curve. This excess capacity above a market participant's minimum requirement is referred to as the "Awarded Excess." NYISO illustrates this in the graph shown below.[3]



The additional capacity procured can be used in other locations to either meet deficiencies or it can be sold to other Market Participants. In 2017, the quantity of excess capacity procured in the spot market was approximately 10% for each region (NYCA, G-J, NYC). This is shown in the table below.

		2017												
		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	% Allocated Excess
NYCA	Minimum Req	36,355	36,355	36,355	36,355	35,513	35,513	35,513	35,513	35,513	35,513	35,850	35,850	
	Excess Sold	4,224	4,126	4,049	4,209	3,529	2,604	3,299	3,332	3,333	3,477	4,194	4,194	10%
NYC	Minimum Req	8,977	8,977	8,977	8,977	9,095	9,095	9,095	9,095	9,095	9,095	9,011	9,011	
	Excess Sold	1,470	1,470	1,500	1,500	748	776	807	809	780	834	1,580	1,581	13%
G-J	Minimum Req	13,827	13,827	13,827	13,827	13,622	13,622	13,622	13,622	13,622	13,622	13,588	13,588	
	Excess Sold	1,530	1,539	1,565	1,573	731	765	798	806	779	834	1,597	1,609	9%
Source: NYISO Annual Installed Capacity Report, December 14, 2018, Attachment VII, p. xiv														

In addition, staff's approach appears to exclude other capacity-related costs that can be avoided by DERs. For example, each utility is required to procure additional capacity (the Installed Reserve Margin[4]) to serve its load plus a reasonable reliability reserve. The NY State Reliability Council determined that

[3] Smith, Zachary. ICAP Demand Curve, Intermediate ICAP Course. November 7-8, 2017.
[4] NYISO Installed Capacity Manual at 6 (https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338).

amount would be 16.8% for the 2019 capability year.[5] Load reducing resources such as DERs reduce the forecasted load, and therefore the amount of reliability reserve capacity that must be procured. The failure to take account of these avoided reliability reserve costs appears to explain some amount of the loss in value between the original ICAP Alt 2 approach and the new approach proposed by Staff.

In order to account for this additional procurement beyond each utility's minimum requirement, CEP recommends that the ICAP Tag be "grossed up" by these additional avoidable reserve and awarded excess requirements in a similar manner as is done to account for losses. Because the errors in staff's approach apply to both ICAP alternatives, the Commission should apply the appropriate gross-up for both ICAP Alternative 1 and 2. The CEP intends to develop further analyses and recommendations on these approaches.

VI. EVOLUTION OF ICAP VALUE

CEP reiterate that we are supportive of the overall concepts advanced in Staff's proposal. We offer the above recommended modifications in order to ensure that the proposals achieve their goals of providing more accurate compensation to DERs. We also recommend that the ICAP value methodology continue to evolve over time as valuation capabilities improve. For example, the current methodology likely undervalues DERs to the extent that DERs are already included in load forecasts, thereby reducing each utility's required capacity purchases and providing significant unaccounted-for ratepayer benefit. To accurately calculate the avoided capacity value, one would estimate the counterfactual market clearing price without DERs in the forecast. We urge Staff to continue to explore these methodological improvements in the future.

Respectfully submitted,

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[5] Technical Study Report: New York Control Area Installed Capacity Requirement For the Period May 2019 to April 2020, http://www.nysrc.org/pdf/Reports/2019%20IRM%20Study%20Body-Final%20Report[6815].pdf at 4.

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