STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

Reply Comments on the Whitepapers Regarding Future Value Stack Compensation Including Avoided Distribution Costs and Capacity Value Compensation

Clean Energy Parties

Dated: March 25, 2019

Introduction

The Clean Energy Parties ("CEP"), including the Solar Energy Industries Association, the Coalition for Community Solar Access, the Pace Energy and Climate Center, the Natural Resources Defense Council, the New York Solar Energy Industries Association, and Vote Solar, file these reply comments to address certain statements in the "Joint Utilities Comments on Whitepapers Regarding Future Value Stack Compensation Including Avoided Distribution Costs and Capacity Value Compensation" ("JU Comments") submitted on February 26, 2019.[1] These reply comments also briefly touch on other party comments submitted in the docket in large part to highlight the JU's minority and out-of-step views on many matters. As the JU Comments in places appear to misunderstand our comments, we also reference and respond in places to the Joint Utilities' reply comments filed on March 13th, 2019. Although we do not address every

[1] Joint Utilities "Comments on Whitepapers Regarding Future Value Stack Compensation Including Avoided Distribution Costs and Capacity Value Compensation," (Case 15-E-0751), February 26, 2019.

comment made by the JU or other stakeholders, our silence on these items should not be interpreted as agreement.

The CEP recommends that the Public Service Commission ("PSC" or "Commission") move forward with an Order on the Whitepaper recommendations (with the modest improvements suggested by the Clean Energy Parties) without delay in order to make progress toward the clean energy future we all desire.

For more than a year, the solar industry and aligned advocates – including advocates for solar energy, community groups, environmental organizations, and social justice organizations – have been recommending changes and improvements to the Value of Distributed Energy Resources ("VDER") tariff. Throughout the Value Stack Working Group process and in various rounds of written comments, these aligned parties have made the case that the current tariff does not accurately reflect the value of distributed energy resources or provide stable enough compensation to help New York achieve the Governor's goal of installing 6 gigawatts ("GW") of distributed solar by the year 2025, which is the minimum amount of distributed solar needed to make progress toward the New York 2015 State Energy Plan goal of reducing greenhouse gas emissions by 80% by the year 2050.[2]

In response to these recommendations, the Department of Public Service ("DPS") Staff published an initial whitepaper in July 2018 proposing changes to VDER and the market transition credit mechanism. Stakeholders submitted extensive comments on that whitepaper. Then, in December 2018, DPS Staff published an additional whitepaper for consideration. In our comments submitted on February 25, 2019, the CEP welcomed the release of this whitepaper and generally supported the direction taken by Staff to correct several challenges with the original VDER tariff.

We appreciate the effort that Staff has put into these proposals. Given the significant amount of debate and deliberation since the adoption of the original VDER tariff, and the well-understood need to improve the VDER tariff, the Commission should act quickly to adopt the proposals in the whitepaper along with the modifications to these proposals suggested by the CEP.

Until the Commission issues an Order that definitively improves the current challenges with the value stack, renewable energy customers and installers will be unable to determine whether such projects will be economically viable, leading to delays or declines in investment and hiring, and a slowdown in the adoption of clean energy projects in the state.

General Rebuttals

A. The DPS Staff Value Stack Whitepaper Recommendations Are An Iterative Step To Help Correct Problems With The Tariff, And Do Not Erode The Progress To Date

[2] New York State Energy Planning Board "Energy to Lead," June 25, 2015. See Overview. Available at: https://energyplan.ny.gov/Plans/2015

The JU comments fail to acknowledge that the original VDER tariff does not fairly balance the original objectives of the Commission, which include not only providing compensation based "on the actual, quantifiable benefits that the resources provide" but also "creating robust and competitive markets for DER that are sustainable over the long term and can maximize value and opportunity for society, the electric grid and consumers."[3] The proposed changes to the VDER tariff in the Staff Whitepaper make progress towards these twin goals.

The proposed changes in the whitepaper indicate a welcome recognition of the fact that elements of the value stack need further refinements. Throughout the Working Group process, of which the JU were a part, Staff made clear that adjustments to the tariff may need to be made to better achieve the Commission's objectives. As Staff states in the Value Stack Whitepaper, the recommendations proposed are intended to "improve the ability of the Value Stack to provide appropriate price signals and compensation so that developers and customers design and invest in projects that provide benefits to the electric distribution grid."[4]

The steps proposed in the whitepaper would not erode the progress to date, nor would they reduce the accuracy and the performance-based approach. Rather, Staff's proposal recognizes that some aspects of the tariff, such as DRV, were achieving a false sense of accuracy and recommends changes that will better align the financial signals sent to customers with the benefits they can provide to the distribution system. In addition, the staff proposal recommends that further work to address the accuracy of the DRV component be undertaken in the context of the updated Marginal Cost of Service Studies.

Further, the proposed DRV remains performance based, with compensation directly dependent on a project's ability to perform in the key windows of time that drive distribution costs. Staff's proposal implements the DRV as a long-run value, which is consistent with the way energy efficiency has been treated to date. As proposed, the DRV changes do not send improper price signals or create unnecessary costs. Similarly, the Community Credit proposal also does not reduce the accuracy or performance aspect of the tariff nor create excessive or unnecessary costs.

B. *The Utilities' Assertions About The State Of The Distributed Solar Market Are Incorrect*

1. *The Interconnection Queues Are Not A Useful Indicator Of The VDER Tariff's Success*

The JU's assertion that the current VDER tariff is driving rapid distributed solar development and is successful based on the size of the current interconnection queues across the state is

[3] New York State Department of Public Service "Staff Whitepaper Regarding the Future Value Stack Compensation Including Avoided Distribution Costs," (Case 15-E-0751) December 12, 2018. At p. 2.
[4] Ibid. At p. 14.

flawed and shows a surprising misunderstanding of the development process for medium-sized to larger-sized solar energy facilities.

In practice, the risks inherent in solar development and construction require that larger projects proceed through a series of investment stages during which project proponents can gain certainty about the viability of the project to attract the substantial capital needed to construct and operate solar projects. A typical project may take anywhere between nine months and several years to progress through the stages before it can be viewed as a viable project that is able to attract capital and be built.

Developers typically begin by negotiating agreements to lease or own the property on which a facility may be built—a process that involves relatively little financial investment. Next, project proponents submit an interconnection application—another relatively low-cost investment that is designed to allow the developer to begin the process of learning if a project may have a viable path and cost for interconnection. In practice, the near compete lack of information about the hosting capacity of New York's distribution grid, and the substantial impact that a good or bad interconnection cost estimate can have on project viability means that successful project developers often submit multiple interconnection applications over several months just to yield a single viable project.

It is only months or sometimes years after a project first enters the interconnection queue—i.e., after permitting and interconnection are complete, and after all of the policy risks have been resolved—that a project will be able to attract the substantial capital (millions of dollars for larger projects) that is needed to construct and operate the facility. In practice, developers may submit dozens of applications per year in the hope that despite the challenges with the VDER tariff, permitting, siting, and tax issues, one of those applications will bear fruit and result in a viable project.

The presence of a project in the interconnection queue is a poor indicator of project viability, because entering the queue is a low-risk action and because the majority of make-or-break development risks (interconnection cost, permitting, tax rate, and policy risk) have not yet been resolved at that stage. Indeed, a large percentage of projects that submit interconnection applications will never be built because one or more of these risks will result in cancellation of the project. As has been discussed extensively in the Interconnection Working Groups, a large number of projects in the current interconnection queue, many with Market Transition Credit Tranche Allocations and Megawatt Block awards, are expected to drop out due to a variety of factors related to the available revenue under the VDER tariff, large interconnection costs, zoning and permitting issues, tax barriers, and other issues.

In addition, the JU assertion that 5,000 MW_{AC} of distributed generation – mostly solar – has entered the interconnection queues since March 2017 is misleading. As of January 2019, the distributed generation ("DG") interconnection queues across the state (excluding LIPA/LI-PSEG which is not reported there in the same manner) had a total of 1,813 MW_{AC} of proposed projects.[5] After queue management was implemented at the end of March 2017, the same interconnection queue across the state had a total of 1,969 MW_{AC}.[6] These totals roughly match the data summaries from DPS on the DG Interconnection website.[7] The overall amount of MW of distributed solar in the interconnection queue has remained relatively steady over the last two years, as projects have been built and new applications have been submitted.

Using actual operating projects or projects that have reached Permission to Operate ("PTO") is a less speculative measure of the success or failure of New York's distributed generation policies. According to the most recent U.S. Solar Market Insight Year in Review, while New York installed more distributed solar in 2018 than ever before, that rate of installation in the non-residential sector that is subject to VDER was only 206 MW_{DC} in 2018, which is roughly 150 MW_{AC}using typical inverter loading ratios. This rate is significantly lower than the multi-gigawatt number touted in the JU testimony, and it is significantly less than the annual rate of closer to 770 MW_{AC}/year that would be needed to reach the state's 6 GW by 2025 goal.[8] In addition, community solar projects and other similarly-sized solar installations still remain a very small portion of the statewide solar market in part based on the problems with the current tariff. Only 17 megawatts of community solar has been installed in New York to date, with 12.3 megawatts (MW) installed in 2018[9] and nearly all of these projects were developed and grandfathered under net metering and are not subject to the value stack tariff.

It is too early and speculative to declare that the VDER tariff has succeeded when, in practice, nearly all projects built to date in New York have not been subject to the VDER tariff.

2. *The Large Scale And Distributed Solar Markets Should Not Be Confused*

It is wrong to say that solar projects proposed to be developed under the Clean Energy Standard ("CES") and eligible for NYSERDA renewable energy credits ("RECs") demonstrate "the health of the small-scale solar industry in New York."[10] These are two completely different market segments for renewable projects, and both market segments are essential from a volume and benefits perspective for New York's planned clean energy transition and decarbonization targets. Distributed generation projects have additional costs and benefits per unit of energy generation. The additional costs are due to their lesser economies of scale and the expense of directly serving customers including customer acquisition costs, costs associated with utility billing, and sometimes greater siting costs. The additional benefits include avoided distribution and transmission costs and direct benefits to customers including bill savings, engagement and empowerment in the energy transition, and ability for communities to integrate clean energy into their building code requirements. For these reasons, the

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[5] See utility reports filed In the Matter of SIR Inventory (Matter #13-00205), February 2019.
[6] Ibid.
[7] New York State Department of Public Service, SIR Inventory Information, January 2019.
[8] Solar Energy Industries Association, Wood McKenzie, "U.S. Solar Market Insight, Year in Review," March 13, 2019. Available at: https://www.seia.org/us-solar-market-insight
[9] Ibid.
[10] Joint Utilities "Comments on Whitepapers Regarding Future Value Stack Compensation Including Avoided Distribution Costs and Capacity Value Compensation," (15-E-0751) February 26, 2019. At p. 3, Note 7.

Commission and Governor Cuomo have made increasing distributed and community solar installations a priority. It is not accurate to say the existence of large-scale solar facilities demonstrates the health of the distributed solar market.

C. The JU Comments Mischaracterize The Cost Of NEM And The VDER Tariff To Date, As Well As The Cost Impacts Of The White Paper's Proposed Improvements

The JU comments mischaracterize the costs of distributed solar to date in the state by continuing to refer to any costs to ratepayers – i.e. residents and businesses on their electric bills – as "out of market payments" and "subsidies". For example, a large portion of the costs that the utilities apparently deem to be subsidies are actually avoided costs associated with the damages due to carbon emissions. The Joint Utilities' workbooks state that they do not include "environmental credits as these cannot be monetized in the current framework and are therefore not avoided costs."[11] In reality, however, DERs can avoid numerous categories of costs that would otherwise be borne by New York ratepayers, whether these costs relate to climate damages and the costs of adaptation (estimated to be in the billions of dollars annually[12]), or to other as-yet-quantified avoidable costs related to conventional air pollutants, air toxics, water and species damages, and other costs. The JU's assertions also ignore the numerous resiliency, security, and economic development benefits provided by DERs.

Changes to DRV

A. The CEP & JU Agree On Shifting The DRV Calculation Window To Later Hours In The Day Because The 2 PM To 7 PM Period Is More Reflective of When Peak Periods Actually Occur

The CEP concurs with the JU – and many other commenters – that the Value Stack Whitepaper's proposed 240-hour window should be shifted later in the day to the hours of 2 pm to 7 pm. As shown in the data provided by the utilities for the last five years, the 2 pm – 7 pm period is more representative of when the utilities' actual peak 240 hours occur.[13] These data are summarized for all of the utilities except for Con Edison in the heat map below.[14] The data show that 45% of the top 240 hours for the utilities analyzed occurred between 2 pm – 7 pm June 1 – August 31, compared to 42% occurring between the hours of 1 pm and 6 pm. In addition, these data indicate that the window should span from June 1 – September 30, as

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[11] This is included as Note 1 in the Summary sheet of the Joint Utilities' attachments A through F submitted with the Joint Utilities' February 25, 2019 comments in this proceeding.

[12] See, e.g., https://www.dec.ny.gov/energy/82168.html ("The ClimAID statewide climate change adaptation study estimates that without adaptation measures, by mid-century annual climate change costs for New York State's key economic sectors may approach $10 billion."); https://www.reuters.com/article/us-climate-newyork-plan/new-york-lays-out-20-billion-plan-to-adapt-to-climate-change-idUSBRE95A10120130612 (describing New York City's $20 billion climate adaptation fund).

[13] Attachments G-L submitted with the Joint Utilities' comments on February 25, 2019 in this proceeding.

[14] Con Edison did not provide aggregated hourly data in the same format as the other utilities, and thus we were not able to include Con Edison's peak load data in this analysis.

many of the top 240 hours in the last 5 years occurred in early June and late September. The hours of 2 pm – 7 pm June 1 – September 1 include 53% of the top 240 hours for the utilities analyzed. For this reason, we propose that the window be expanded to June 1 through September 30.

	7 AM	8 AM	9 AM	10 AM	11 AM	12 PM	1 PM	2 PM	3 PM	4 PM	5 PM	6 PM	7 PM	8 PM	9 PM	10 PM	Total
JAN	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	2%	1%	1%	0%	0%	7%
FEB	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%	0%	3%
MAR	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
APR	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MAY	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
JUN	0%	0%	0%	0%	0%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	9%
JUL	0%	0%	0%	1%	1%	2%	3%	4%	4%	5%	5%	4%	3%	2%	1%	1%	37%
AUG	0%	0%	0%	0%	1%	2%	2%	3%	3%	4%	4%	3%	2%	2%	1%	0%	27%
SEP	0%	0%	0%	0%	0%	1%	1%	2%	2%	2%	2%	2%	1%	1%	1%	0%	15%
OCT	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
NOV	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
DEC	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
Total	0%	1%	1%	2%	3%	6%	8%	10%	11%	12%	13%	13%	10%	6%	3%	1%	

Jun 1 - Aug 31	1 pm - 6 pm	42%
	2 pm - 7 pm	45%

Jun 1 - Sep 30	1 pm - 6 pm	50%
	2 pm - 7 pm	53%

B. The JU's DRV Adjustment Factor Proposal Should Be Rejected

The CEP strongly oppose the JU's proposal to use an "adjustment factor" to reduce the DRV credit to reflect solar generation during the utilities' top ten hours. As we have pointed out in previous comments, it is not just the top ten hours that drive investments in the distribution system – it is hundreds of hours. Nor do the utilities conduct distribution system planning by identifying only the top ten hours on the system. Instead, the utilities design their system to serve peak load based on a multi-scenario simulation or estimate of the hours in which the peak is likely to occur. In other words, traditional distribution system planning takes into account windows of time during which peak loads may occur, rather than pinpointing a precise moment in time. This approach is mirrored in the kind of approach proposed by staff for the DRV and capacity components of the tariff.

DER performance should not be incentivized for only 0.1 percent of the hours of the year. Instead, DERs should be incentivized to reduce distribution system loads during a larger number of peak hours to reduce the number of hours that equipment may be overloaded during the season. It is the sustained overloading of equipment that results in equipment upgrades. For example, Central Hudson has specified explicit risk tolerances that generally exceed 200 hours of overloading on various types of distribution equipment.[15] Basing compensation on these

[15] For example, Central Hudson's 2016 avoided distribution study specifies that load can exceed the design ratings of urban substations for 263 hours and rural substations for 350 hours before it will initiate infrastructure upgrades. *See:* Nexant, Location Specific Avoided Transmission and Distribution Avoided Costs Using Probabilistic Forecasting and Planning Methods, 2016, p. 3. Accessed: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B6ED0A866-16AB-4ED5-9F6E-AA67AA42B878%7D

sustained periods of use is consistent with how the utilities plan their system and consistent with the DPS Staff recommendations.

In addition, the lack of visibility or notification as to the hours is unnecessary and unacceptable and cannot be a part of any approach. For these reasons, the JU's adjustment factor should be rejected.

C. The JU's Argument That Their Updated Marginal Cost Study Avoided Cost Values Should Be Used Is Inappropriate As These Studies Have Not Been Rigorously Reviewed Or Subject To Stakeholder Critique And Feedback, And Many Questions Remain About the Ways In Which These Values Were Calculated

The JU argues that using the avoided cost values that have been approved for use in the energy efficiency proceedings is inappropriate, as the utilities have since filed updated avoided distribution cost (marginal cost) studies. However, these new studies have not been thoroughly vetted or approved by the Commission. Nor have they been subject to rigorous stakeholder review and examination. Based on our review of these studies, we continue to have many concerns and questions regarding the utilities' methodologies.[16] For example:

1. There is a general lack of transparency in the methodologies, weather assumptions and economic growth assumptions used in the utilities' load forecasts, and a failure to address how load forecasts must evolve given the state commitment to decarbonization by 2050 or sooner and the required likely doubling of electric consumption to accomplish that.
2. There appear to be many inconsistencies between the marginal cost of service studies and the capital investment plans.
3. The marginal cost studies limit the distribution system benefits provided by DERs to those associated with load growth only.[17] Distribution benefits should also consider DERs' ability to avoid costs associated with other types of investments beyond those for load growth. These benefits would include reliability and regulation benefits, new information from situational awareness through communication and sensing equipment, and reliability services such as back-tie services. These benefits were not addressed by the utilities.
4. We have concerns about the utilities' derating of DER capabilities, as well as the system planning criteria and design thresholds used in screening out or limiting the ability of DER resources to provide load relief.

Further, the dramatic reduction in value from the studies filed in 2017 and some of the studies filed in 2018 raises many questions about changes in the utilities' assumptions and methodologies.

[16] Clean Energy Parties "Updated DSIP Comments", (Case 16-M-0411) November 27, 2018, At p. 5.
[17] Ibid At p. 17.

The CEP urge the Commission not to approve these values until the methodologies and assumptions that inform them are thoroughly examined through a proceeding designed to investigate these issues.

D. The Five Percent Cap Adjustment Band Likely Undervalues The Benefits DER Provides Rather Than Creating A Subsidy

The Joint Utilities claim that the collar on biannual adjustments to the DRV credit will create a subsidy for many years. However, as mentioned above, the Joint Utilities are ignoring the concept of DRV as a long run value for avoided distribution and transmission costs at present and in the coming years where we need to double the current electric load in the state to achieve 80% decarbonization by 2050 or sooner. As the CEP has explained in previous comments and presentations, the avoided distribution value provided by DERs can be expected to be long-term, in most cases lasting for the life of the DER asset. Indeed, the utilities' own marginal cost of service study methodologies reflect this assumption by including existing (and in some cases, projected) DER in the baseline for their load forecasts.

The 5% collar—like other aspects of the proposal—is an iterative step toward providing appropriate market signals to DERs while more work is done on the DRV value to allow it to be both more accurate and usable. In practice, the 5% cap will likely constrain the DRV value for projects deployed in the near-term, resulting in a probable undervaluation of the benefits these DERs will provide in the future, rather than creating a subsidy.

Despite believing that compensation for new assets should be fixed or collared based on the current DRV value at the time a resource is installed, the Clean Energy Parties support the adoption of the 5% collar at this time because of the relative certainty that such a cap provides, which is crucial for DRV usability and project financing. The JU's proposal to increase the size of the collar beyond 5% would severely compromise the financeability of the DRV component, thereby recreating the current challenges in the VDER tariff that Staff is attempting to remedy.

Sunsetting the Locational System Relief Value (LSRV)

A. The CEP Support Sunsetting the LSRV

The Joint Utilities oppose the sunsetting of the LSRV, claiming that doing so removes the price signals that encourage developers to locate resources in high-value areas of the distribution system or to adopt project designs and technologies that provide real distribution system benefits.[18] Curiously, the Joint Utilities discount the ability of non-wires solicitations (NWSs) to provide strong signals to locate in specific areas, stating that developers are likely to choose DRV compensation over non-wires solicitations. The Joint Utilities' critiques are unfounded and,

[18] Joint Utilities "Comments on Whitepapers Regarding Future Value Stack Compensation Including Avoided Distribution Costs and Capacity Value Compensation," (15-E-0751) February 26, 2019. At p 8.

confusingly, contradict their previous positions on the LSRV.[19] In practice, the DRV is based on an average of system marginal costs, and by design the DRV is much lower than the potential NWA compensation in locations where investment needs are high. Developers are likely to continue to design projects to meet the needs of high-value areas through non-wires solicitations, so long as those NWS are designed and advertised appropriately.

At the same time, CEP does acknowledge that the NWS process should be improved, as we are not seeing the number of successful NWSs expected. The CEP recommend reviewing the existing challenges with how the NWS opportunities are created, contracted, and structured. Many of these challenges were outlined by the New York Battery and Energy Storage Technology Consortium (NY-BEST) in their comments filed on September 10, 2018 in Case 18-E-0130.[20] The CEP agree with many of the challenges noted by NY-BEST, including that contract term lengths are often too short and should be at least for seven years.

The Joint Utilities argue that the DRV must exclude high-value, locational needs. While the CEP agree that locations that have contracted non-wires alternatives should be excluded, it is inappropriate to exclude locations without non-wires alternatives from the calculation of the DRV once the LSRV is no longer offered. Not all developers are able to participate in non-wires solicitations or demand response programs, yet they can still provide value to the system. These projects should be compensated based on the DRV, which includes both low-value and high-value areas without non-wires solicitations.

Community Credit

As discussed above, the Joint Utilities' misunderstand the state of the distributed solar market, including the current rate of development, the need for the market, the additional benefits and avoided costs, and the economics needed for projects to be developed. The Joint Utilities do recognize the financing improvements community solar projects would realize from being able to include a creditworthy anchor, but argue that the Community Credit is unnecessary to support projects.[21] The Joint Utilities also argue that the community credit will increase customer costs and result in demand-billed customers participating in remote CDG projects rather than "more efficient" customer sited projects.[22] These arguments should be rejected.

A. The Community Credit Is Necessary To Establish A Healthy Distributed Solar Market

[19] During prior working group conversations, various utility representatives have objected to the LSRV on the grounds that the NSW process is a better mechanism for encouraging DERs to locate in grid-constrained areas.
[20] New York Battery and Energy Storage Technology Consortium "Comments on the Energy Storage Deployment Program" (Case 18-E-0130) September 10, 2018.
[21] Joint Utilities "Comments on Whitepapers Regarding Future Value Stack Compensation Including Avoided Distribution Costs and Capacity Value Compensation," February 26, 2019. At p.17
[22] Ibid, At p. 18

The Joint Utilities' argument that a community credit is unnecessary is flawed in two ways. First, as discussed above, it is clear from NYSERDA's modeling and the generally weak state of the market that additional value is both justified and needed to spur distributed solar deployment towards the 6 GW target by 2025.

In addition, asserting that the community credit is "unnecessary" presumes that the inclusion of non-residential customers is not an objective of the community distributed generation program established by the Department in 2015.[23] Yet that Order envisioned demand rate customers comprising up to 40% of a project's subscriptions. The current barrier to the participation of non-residential customers is a result of the challenges of the first iteration of the VDER tariff, and the community credit approach is an important interim measure to ensure non-residential participation in CDG projects. This innovation will have the important benefit of facilitating the financing of community solar projects, thereby improving access to clean energy for residential, as well as commercial, governmental and institutional customers.

B. The Community Credit Should Be Extended to Demand Rate Customers

The Joint Utilities' assertion that the community credit will result in a less cost-effective outcome than if customers installed renewable energy facilities on-site is unsubstantiated and misplaced. One of the chief benefits of a community distributed generation program is that it addresses the common situation in which a customer cannot host its own distributed energy project due to an inability to fully control its premises, a lack of space or the presence of shading, an unsuitable roof or parking area, or other barriers. This is as true for demand-rate (non-residential) customers as it is for homeowners and renters. At the same time, there are facilities which may be structurally well suited to host a project, but for which the resident customer is not a good offtaker for the project. Warehouses are a good example of this: often there is a large roof available to support a project, but the customer occupying the building is a tenant and has minimal load, making development of a project serving onsite load unviable.

In addition to the physical limitations restricting the ability of many non-residential customers to host a solar system, the utilities' argument that customer sited projects should be preferred instead is ill supported. The Joint Utilities have argued that onsite solar projects would be more cost-effective than off site projects. However, they have made no demonstrations that that is true. Indeed, while the JU's comments claim that on-site projects would be more efficient because they would reduce line losses and be sited close to load, these comments fail to consider the possibility that the development of other distribution-connected CDG projects on circuits that also serve load will also reduce line losses.

[23] New York State Public Service Commission "Order Establishing A Community Distributed Generation Program and Making Other Findings," (15-E-0082), July 17, 2015. At p. 8.

ICAP Whitepaper

A. The CEP & the JU Agree that More Recent Data Should Be Used to Establish ICAP Hours, but There Should be a Known Set of Hours and Those Hours Should be Constant for Projects Once They Qualify for the Tariff, and Only be Updated for New Projects Going Forward

The Joint Utilities argue that DPS should use more recent data to establish installed capacity ("ICAP") coincidence. They argue that 2014-2018 is a more appropriate time period than using data from 1993-2018 given that the electric system has changed considerably during the past 25 years. More recent data would likely provide better insight into current trends.[24] The CEP agrees with the Joint Utilities on using these data, and also believe these data support our proposal to set the ICAP and DRV periods from 2 PM - 7 PM per our comments.[25] As we also stated in our original comments and NY Best discussed, these hours selected should be constant for projects once they qualify for the tariff, but should be updated at a regular interval for new projects going forward.

Support for Whitepaper Recommendations from Other Parties

The CEP note the general support for the DPS Staff Whitepaper recommendations from other aligned parties, as well as the agreement on certain modifications proposed by the CEP. For example, Acadia Center agrees with the recommendation to spread the DRV calculations over more hours of the year, including into September, and supports the view that the DRV is too unpredictable to support DER projects. Acadia Center also supports extending the community credit to anchor customers.[26]

Furthermore, AEEI/ACE NY/NECEC, largely agrees with reforming the approach to calculating the DRV and allowing customers in the CSRP. AEEI/ACENY/NECEC also supports extending the hours used to calculate DRV during the 2 pm to 7 pm period -- consistent with the CEP and JU recommendations -- but suggests that projects with storage should have the option of selecting a slightly different set of hours.[27]

Lastly, the CEP points out that on balance, comments from groups representing firms seeking to install DER, as well as non-market actors, such as environmental groups, favor the Whitepaper recommendations, and most of these comments also recommended minor amendments to the Staff's approach. The JU's comments, in contrast, appear to be based on a fundamental misconception of the realities of New York's distributed energy marketplace and of the kinds of

[24] Joint Utilities "Comments on Whitepapers Regarding Future Value Stack Compensation Including Avoided Distribution Costs and Capacity Value Compensation," February 26, 2019.. At p. 22
[25] Clean Energy Parties "Comments on Staff Capacity Whitepaper," February 25, 2019. At p. 6
[26] Acadia Center "Comments on VDER Compensation for Avoided Distribution Costs and MTC Replacement," February 25, 2019, At p. 1-2.
[27] Advanced Energy Economy Institute, Alliance for Clean Energy New York, Northeast Clean Energy Council, "Comments on Staff Rate Design White Papers," February 25, 2019, At p. 3.

changes that are necessary to fully animate the kinds of distributed energy markets envisioned by the Commission.

We appreciate the opportunity to submit reply comments on these important matters and look forward to the speedy adoption of the important improvements proposed in Staff's most recent whitepaper.

Respectfully submitted,

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