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 Future Value Stack Compensation, Including Avoided Distribution Costs

Dated: February 25, 2019

Comments to New York State Department of Public Service

On Whitepaper Regarding Future Value Stack Compensation,
Including Avoided Distribution Costs

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I. INTRODUCTION AND SUMMARY

On December 12, 2018 the New York Department of Public Service released a its *Whitepaper Regarding Future Value Stack Compensation, Including Avoided Distribution Costs* - which addresses the Demand Reduction Value (DRV) and Locational System Relief Value (LSRV) compensation mechanisms, as well as the Market Transition Credit (MTC)/community solar credit.

The Clean Energy Parties (CEP) welcome the release of this December 12 whitepaper, and we appreciate both the effort that Staff has put into these proposals and the opportunity to provide comments on the proposed mechanisms.

We strongly support the proposals that Staff has put forward. We see these proposals as a critical step forward towards more properly valuing DERs and increasing their deployment rate in the state as we build towards 70% of New York's electric system being sourced from renewable energy by 2030, including over 6 GW_{AC} of distributed solar.

Staff's proposals represent an important first step towards both fixing a DRV compensation mechanism that has failed to provide appropriate market signals to achieve distributed energy resource (DER) deployment, and providing greater visibility for project development through an update to the MTC structure and MW volume that, in coordination with the new DRV approach, reduces costs for ratepayers. Given the two-year development cycle for many projects, these improvements in combination with the Whitepaper Regarding Capacity Value Compensation and the NY Sun MW Block program will allow DER project development to continue in many areas for another year, allowing projects to be brought online not just in 2019 and 2020, but now in 2021.[1]

Our comments here are intended to detail and recap the reasons for our support of these proposals and to highlight a couple areas where we believe a modest adjustment to Staff's proposals should be made.

II. THE CLEAN ENERGY PARTIES URGE SWIFT ADOPTION OF THE WHITEPAPER

Since the July 2018 release of the original paper on distribution capacity and the market transition credit, developers have been making investment decisions based on the proposals in Staff's paper which recommends that the Commission allow projects that made 25% interconnection payments after the paper's release date to qualify for the changes recommended within the paper. It is important to bring some certainty to the market through swift adoption of changes to the DRV and adoption of the Community Credit.

[1] We would note, however, that this deployment rate is not yet sufficient to reach the 6 GW_{AC} by 2025 target nor does it provide the needed minimal market visibility of 4-5 years out which would allow greater investment and meaningfully reduce costs.

III. COMMENTS REGARDING PROPOSED CHANGES TO THE DRV

A. Use of System-Wide Marginal Cost Rather than De-averaged DRV

The first change to DRV proposed in the Staff whitepaper is to replace the de-averaged DRV with the system wide marginal cost estimates used for energy efficiency (EE) benefit-cost calculations, starting with those values from the MCOS studies used to calculate the original 10-hour DRV.[2] Projects that qualify after July 26, 2018 would receive DRV compensation based on these EE values, with no additional "derating" or other adjustment for resource performance. These values would be updated in the Value Stack tariffs no more frequently than once every two years, following the review and input process established for the biennial marginal cost study filings.[3] The current values are shown in the table below, and are generally similar to, but not the same as the current DRV.

	Central Hudson	ConEd	NGrid	NYSEG	RG&E	O&R
EE Values	$14.55	$226.00	$66.48	$30.84	$31.58	$70.00

CEP supports the use of these marginal costs used for the utilities' EE benefit-cost calculations for the DRV, as these values have been vetted and approved by the Commission and because no better proxy exists for the avoided distribution cost value that DER can provide. CEP continues to support the development of robust, transparent marginal cost values through an adequate stakeholder process going forward.

Although we support the use of these values in the interim, we continue to encourage the Commission to work with stakeholders to more accurately identify and quantify the benefits that DER are providing and to incorporate these benefits into the VDER tariff; we expect this will come through work on improving the methodologies employed in the utilities' Distribution System Implementation Plans.

B. Performance Requirements for DRV

A key change to DRV proposed in Staff's whitepaper is to spread DRV compensation over the top 240-245 summer peak hours. Specifically, the total $/kW-Year values would be based on the peak summer hours between 1 PM and 6 PM Daylight Savings Time on non-holiday weekdays from June 24th to August 31st. We address the number of peak hours first, followed by a discussion of the hours selected.

1. The Switch from 10 to 200+ Hours Is Justified and Reasonable

The move to include more than the top 10 hours in the performance period is fully justified, as it more accurately represents how utilities plan their distribution system to meet peak loads. While the utility may use a theoretical peak load hour and day in distribution planning, the distribution system must be

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[2] Staff Whitepaper, p. 7
[3] Ibid.

capable of meeting the peak whenever it occurs and under probabilistic scenarios that include abnormal weather events (e.g., 1 in 10 weather events). For this reason, a set of hours within which peaks are likely to occur encourages distributed energy resources to be performing during hours which may otherwise drive distribution system upgrades.

In addition to the probabilistic nature of distribution peaks, loadings on distribution system equipment can exceed that equipment's design rating for short periods of time; what matters for many types of equipment and many kinds of wear and tear is not so much the single peak hour (or top ten hours), but rather how long that equipment is overloaded. Distribution equipment planning thresholds frequently exceed 200 hours of overloading.[4] Therefore, it is much more accurate to send resources a price signal to reduce equipment loadings for more than 10 hours per year, and CEP is supportive of Staff's proposal to use the peak summer hours (excluding weekends and holidays).

Beyond being a superior representation of distribution system needs, Staff's proposal to move away from the backward-looking (and almost entirely unpredictable) 10-hour period to a set number of hours around which DER customers can design their equipment is a significant improvement over the original DRV concept from the perspective of DER developers. By establishing a known period over which DRV compensation will be calculated, the new proposal will enable DER customers to design their equipment to actually target the identified peak period. This key change will help to achieve one of the principal goals of the VDER tariff, which is to encourage the design and deployment of DERs so that they provide the most benefits to the system as a whole.

2. Peak Days and Hours Should Be Extended in Light of Data on Distribution Peaks

Although CEP welcomes the improvements to DRV, we recommend slightly changing the dates and hours over which compensation would apply. Not only do we believe that the data support a June 1 – August 31 timeframe and 2 pm – 7 pm window, but we also emphasize that shifting the peak period to 1 pm – 6 pm would disincentivize solar projects with trackers and energy storage.

Dates: The proposed dates over which DRV performance would be measured appear overly restrictive. We believe that the dates should be extended to June 1, and possibly also into September. This is because two of the past 15 NYISO peak days have occurred in early June (both in 2004 and 2008), and one (2014) occurred in early September. In addition, an examination for the utilities' peak distribution hours reveals that many distribution peaks occur in early June. Based on each of the utilities' top 10 hours for 2017 shown in the Value Stack Calculator,[5] 25% of the top hours occurred before June 18 and 10% occurred in September.[6] Therefore, we recommend extending the DRV performance period from

[4] 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, http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B6ED0A866-16AB-4ED5-9F6E-AA67AA42B878%7D

[5] NYSERDA Value Stack Calculator available at https://www.nyserda.ny.gov/-/media/NYSun/files/VDER-ValueStack-Calculator.xlsb

[6] 150 top hours were reported (10 top hours for each of the five utilities), and 37 of these hours were in early to mid-June – more than double the number of top hours that occurred in August.

June 1 to at least August 31.[7] This would also be consistent with NYISO's definition of the summer peak hour period.

Hours: We believe that the 2 pm to 7 pm window is at least as appropriate, if not more so, than the 1 pm to 6 pm window. Again, based on 2017 utility data, more distribution peaks occurred in the range of 2 pm to 7 pm, rather than 1 pm to 6 pm.[8] For example, 22% of the top ten summer hours in 2017 occurred after 6 pm. By contrast, only 11% occurred before 2 pm, and all of the peak hours occurring before 2 pm in 2017 were in ConEdison's territory. Indeed, 78% of the distribution peak hours in 2017 were between 2-7 pm. The distribution of hours and months is shown in the table and graph below.

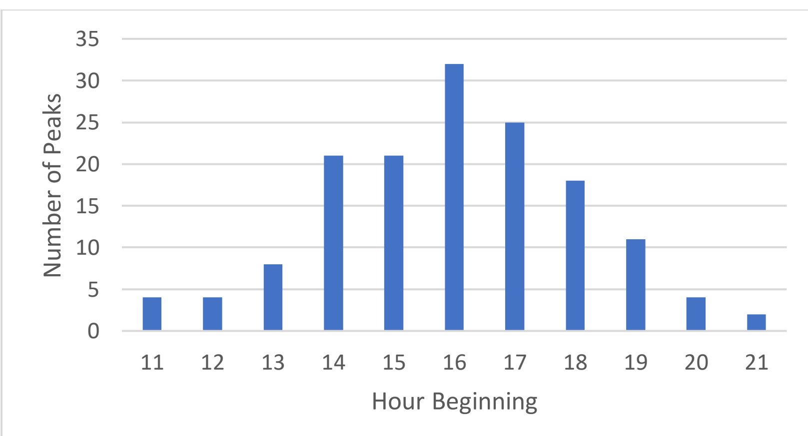
Figure 1. 2017 Top 10 Distribution Peak Hours Across New York Utilities

	Hour Beginning											
Month	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM	**Total Hours**
June	0	0	0	5	6	8	5	5	4	2	2	37
July	4	4	8	11	10	15	13	7	4	2	0	78
August	0	0	0	2	1	5	3	3	0	0	0	14
September	0	0	0	3	4	4	2	1	1	0	0	15

	11:00 AM	12:00 PM	1:00 PM	2:00 PM	3:00 PM	4:00 PM	5:00 PM	6:00 PM	7:00 PM	8:00 PM	9:00 PM
Total	4	4	8	21	21	32	23	16	9	4	2
1 pm - 5:59 pm			105								
2 pm - 6:59 pm				113							

As the chart below demonstrates, the peak hours on the distribution system frequently extend into the early evening hours. We expect that the peak period may shift even later in the future as additional solar comes online.

Figure 2. Frequency Distribution of 2017 Top 10 Distribution Peak Hours Across New York Utilities



[7] It is possible that the September peak hours in 2017 were unusual. Since only one NYISO peak hours in the last 15 years has occurred in September, it may be more appropriate to retain the June – August season at this time.

[8] 105 of the top hours (June through September) occurred between 1 pm and 6 pm, while 113 hours occurred between 2 pm and 6:59 pm.

Given that the bulk of the distribution system peaks for which data is available occur in the 2 pm -7 pm timeframe, CEP recommends that the 2 pm – 7 pm peak period definition be maintained, as it is the most accurate reflection of the current data and likely future trends, and also in order to incentivize resources that can generate later in the day (such as storage-paired solar and solar arrays with tracking systems). However, to encourage some systems to continue to reduce early afternoon peaks, we recommend that Staff also create a 1 pm – 6 pm peak window option for systems to opt into.

1. Grandfathering for Systems Making 25% Payments Prior to December 12 if the Above Change is not Made

Despite the data and arguments above, if the 1 pm - 6 pm proposed peak period is kept, CEP requests that systems that have already submitted their 25% interconnection payments be allowed to opt into the June 1 – August 31, 2 pm – 7pm peak period proposed in the July Staff whitepaper, as these systems may have been designed to maximize production during the later hours based.

2. Smoothing Allocation of DRV Credits for Customers

CEP recommends clarifying that the DRV value will be part of the value stack bill credits transferred to customers. In addition, CEP strongly recommends that host accounts be able to allocate DRV credits to benefiting accounts evenly over the course of the year, even if these credits are accrued during the summer peak hours. This is how the DRV crediting is currently structured, per the March 9, 2017 VDER Order: the DRV value earned in a given year is divided by 12 and credited to subscriber accounts in 12 equal monthly amounts in the following year. We recommend the Commission clarify that this credit smoothing mechanism will remain in place in concert with any updates to the DRV calculation methodology that are adopted.

As many community solar subscription product offerings are moving to a model where a customer's subscription price is based on a percentage of the bill credits allocated to them (e.g., subscription price per kWh is 90% of bill credit value), it is important for customers that community solar providers be able to allocate credits evenly over the year for ease of customer experience. Large changes in customer bills month to month create confusion for customers. In the case of projects that have already been subscribed, the primary customer education process has already been completed, and changes to the customer experience can drastically impact customer confidence and willingness to participate. Additionally, customers carrying large amounts of banked credits gives the impression of overallocation and poses a risk to customer savings in the event that a subscriber needs to unexpectedly close their account.

C. An Additional Option for Dispatchable Resources

The Staff whitepaper proposes that dispatchable resources be able to opt out of DRV compensation and instead participate in the utilities' demand response programs (i.e., the Commercial System Relief Programs (CSRPs)). These programs provide a 21-hour advance call signal and compensate resources based on their performance during events. Rather than grandfathering existing DERs, Staff proposes that existing resources be permitted to either opt into the new DRV or participate in the CSRP. The utilities would need to modify the rules of their CSRPs to permit resources to perform by injecting electricity into the distribution system.

This proposal is justified by the desire to leverage an existing well-functioning program rather than creating a new program. CEP supports the forward-looking call signal approach as an improved delivery mechanism that more accurately reflects the unique demand-reduction benefits that dispatchable DERs can provide, and we look forward to developers and investors further exploring and getting comfortable with the CSRPs.

D. Compensation Period and Five Percent Collar

In addition to the above, one of the most important changes to the DRV mechanism is the introduction of a 5 percent collar, and the extension of the compensation period to 25 years. Under the Staff's DRV compensation proposal, the base DRV value would be subject to change every two years from there subject to a maximum adjustment of 5% in either direction at each reset.[9]

Given the approach to DRV as a long-run stable value spread over time and across a utility service territory, CEP supports the alignment of the compensation period with the time period over which DERs will be providing distribution services to the grid; i.e., 25 years. This change is necessary to meet VDER's goal of compensating distributed resources for performance in line with distribution system needs. CEP also recognizes that Staff's proposal on the 5% collar provides stability in the price signal and represents an improvement over the current DRV variability.

CEP's core concern with Staff's approach is that it could cause compensation to deviate substantially from the actual value provided by resources. CEP's understanding of Staff's proposal is that the DRV values would be set based on the energy efficiency marginal cost values, and then adjusted towards any new marginal cost of service (MCOS) values gradually. However, the base DRV values would not be reset for new resources; rather, all resources would receive the DRV value in effect in that year. For example, in the case of Central Hudson the beginning value is set to $14.55/kW-year. If, in 2020, the marginal cost were found to be $60/kW-year, then a project would only receive $15.28/kW year (105% of $14.55). According to our understanding of Staff's proposal, this value would also apply to a new project installed in 2020, and also to subsequent projects (subject to a 5% adjustment). This is shown in the table below.

[9] Staff Whitepaper, Pg. 7

Figure 3: 5% collar and future DRV capacity as envisioned in Staff paper

			Central Hudson DRV ($/kW-year)			
Year	**Hypothetical Adjustment**	*Multiplier*	**Project installed in 2019**	**Project installed in 2020**	**Project installed in 2021**	**Project installed in 2022**
2019		*1*	$14.55			
2020	*5% Adjustment*	*1.05*	$15.28	$15.28		
2021		*1*	$15.28	$15.28	$15.28	
2022	*5% Adjustment*	*1.05*	$16.04	$16.04	$16.04	$16.04
2023		*1*	$16.04	$16.04	$16.04	$16.04
2024	*5% Adjustment*	*1.05*	$16.84	$16.84	$16.84	$16.84
2025		*1*	$16.84	$16.84	$16.84	$16.84
2026	*5% Adjustment*	*1.05*	$17.69	$17.69	$17.69	$17.69
2027		*1*	$17.69	$17.69	$17.69	$17.69
2028	*5% Adjustment*	*1.05*	$18.57	$18.57	$18.57	$18.57
2029		*1*	$18.57	$18.57	$18.57	$18.57
2030	*5% Adjustment*	*1.05*	$19.50	$19.50	$19.50	$19.50
2031		*1*	$19.50	$19.50	$19.50	$19.50
2032	*5% Adjustment*	*1.05*	$20.47	$20.47	$20.47	$20.47
2033		*1*	$20.47	$20.47	$20.47	$20.47
2034	*5% Adjustment*	*1.05*	$21.50	$21.50	$21.50	$21.50
2035		*1*	$21.50	$21.50	$21.50	$21.50
2036	*5% Adjustment*	*1.05*	$22.57	$22.57	$22.57	$22.57
2037		*1*	$22.57	$22.57	$22.57	$22.57
2038	*5% Adjustment*	*1.05*	$23.70	$23.70	$23.70	$23.70
2039		*1*	$23.70	$23.70	$23.70	$23.70
2040	*5% Adjustment*	*1.05*	$24.89	$24.89	$24.89	$24.89
2041		*1*	$24.89	$24.89	$24.89	$24.89
2042	*5% Adjustment*	*1.05*	$26.13	$26.13	$26.13	$26.13
2043		*1*	$26.13	$26.13	$26.13	$26.13
2044	*5% Adjustment*	*1.05*		$27.44	$27.44	$27.44
2045		*1*			$27.44	$27.44
2046	*5% Adjustment*	*1.05*				$28.81

CEP is concerned that if the DRV were to increase substantially due to new forecasted load growth (such as from growth in electric vehicles, heat pumps, or even from an increase in extreme weather events), the compensation would be limited to only 5% above the previous year's value. This could lead to significant divergence between the actual avoided cost and the DRV compensation, resulting in less deployment of cost effective DERs and therefore greater need for distribution utility investment.

For this reason, CEP proposes that there should be an opportunity for stakeholders to request a reset of the DRV if the results of the MCOS studies reveal that the true value should be significantly higher. In other words, the DRV proposed in the Staff whitepaper (and periodically adjusted within the 5% collar) should serve as a floor for future DRV compensation, with the opportunity to request a DRV reset should the difference between the DRV and the actual value grow large.

E. DRV Application

As discussed below regarding the Community Credit, we support Staff's proposal that would create a Community Credit for all subscribers to CDG projects while ensuring those customers receive DRV compensation as part of the underlying value stack.

IV. LSRV PHASE OUT

Staff Proposal

Staff proposes that the LSRV be phased out. Instead of continuing the LSRV, Staff proposes that any projects that can provide the specific functionality and performance requirements of either non-wires alternatives (NWAs) or demand response (DR) programs participate in those opportunities to receive compensation for the grid services they can provide. Existing projects would continue to receive the LSRV for the 10-year term, but no new projects would be eligible for an LSRV. Staff states that the rationale for this proposal is that the DSIP process and its related NWAs and DR programs are more effective tools for addressing location-specific functions and performance needs. Staff also proposes to continue to work to develop additional mechanisms for identifying and providing prices signals and compensation for distribution system needs. In addition, Staff clarifies that resources receiving value stack compensation may also participate in programs that offer compensation based on local distribution values such as NWA and DR programs.

While CEP generally supports this approach, it creates increased pressure to ensure that the NWA process is effective. Currently, there is relatively little transparency regarding NWA solicitations and the process for identifying NWAs. Nor have the utilities provided transparent feedback to contractors who were not selected, which makes it difficult for DER providers to understand how to design solutions that are competitive with the utilities' traditional infrastructure. New York's current approach stands in contrast to California, where utilities submit annual comprehensive filings on grid needs, and then a Distribution Planning Advisory Group reviews the needs and recommends a final list of distribution deferral opportunities that should be put out to bid.[10] The California Public Utilities Commission Staff note that this process provides "enhanced opportunities for the Commission and stakeholders to review the assumptions and results of the annual planning process while establishing new DER integration objective that help accomplish state climate and energy goals and realize ratepayer benefits."[11]

Although the New York utilities currently file annual capital investment plans and biannual DSIPs, there is no formal link between these documents, nor any formal opportunity for stakeholders to review the capital investment plans and help to identify areas where DERs can avoid investments. CEP recommends

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[10] The CPUC order establishing the Distribution Planning Advisory Group (DPAG) requires that "the IOUs' proposed DPAG agendas shall, at a minimum, encompass a review of: 1) planning assumptions and grid needs reported in the GNA; 2) planned investments and candidate deferral opportunities reported in the DDOR; and 3) candidate deferral prioritization. Importantly, as part of the discussion on candidate deferral opportunities, the IOUs shall present the underlying technical and operational requirements that a given DER alternative must provide in order to successfully meet the underlying grid need." CPUC Decision 18-02-004 February 8, 2018, p. 7

[11] CPUC Distribution Investment Deferral Framework Staff Proposal, R. 14-08-013, p. 6

that a Distribution Planning Advisory Group be established in New York. In California, this group includes the utilities, Commission technical staff, and a wide array of stakeholders, as well as an independent professional engineer. Further, DER developers are also allowed to participate in the group, subject to the execution of a non-disclosure agreement.

V. COMMUNITY CREDIT FOR NEW CDG PROJECTS AND DRV FOR ALL CUSTOMERS OF NEW CDG PROJECTS

Staff proposes that new CDG projects in National Grid, NYSEG, and RG&E's territories receive a Community Credit of $0.0225/kWh and updates the tranche sizes for that. This credit would apply to all customers, not only mass market customers. CEP strongly supports Staff's proposal, and agrees that it will encourage large, anchor customers in CDG projects, will lower CDG project costs, and provide slightly greater visibility for project development. CEP also supports the inclusion of the 1 cent/kWh anchor-tenant credit as a measure to encourage more mature CDG projects that already have tranche allocations to seek anchor tenants.

The Community Credit is a substantial improvement over the MTC construct

Many local governments and other non-residential customers have been interested in pursuing sustainability goals and realizing the economic benefits of participation in community distributed generation projects but have been frustrated by the structure of VDER which provides only a DRV credit that makes demand rate customers non-viable participants in CDG projects. The widespread demand for non-residential CDG projects and an interest in the solution created by the Community Credit is evident by the thirty-four environmental, community and environmental justice groups that called for an expansion of the MTC to all customers[12].

By providing all customers with DRV compensation and extending the Community Credit to both demand rate and residential customers, the changes proposed in the Staff whitepaper create headroom under the ratepayer impact construct described in the March 2017 VDER Order while expanding access to community solar to a broader set of customers in the state. The MTC, which is only available to non-demand customers and entirely replaces the DRV credit for those customers, was made available in tranches that were sized based on estimates of the cost impacts to residential customer classes in each service territory. By offsetting some of the project compensation that would otherwise come from the MTC with DRV credits and extending the Community Credit to customers in non-residential rate classes, the Commission will enable greater DER deployment at a lower cost to ratepayers.

As the Staff paper notes, extending the Community Credit to demand rate customers also has the effect of reducing financing costs for community solar projects. The 2015 community solar order envisioned up to 40% of a project being subscribed by a single non-residential customer as is common practice in leading community solar markets. However, the structure of VDER, as described above, has made these customers unviable as subscribers. This has the effect of removing a credit worthy entity that can derisk a community distributed generation project in the eyes of a financier and thereby lower financing costs

[12] "Comments of 34 Organizations", filed in 15-E-02703 by the Alliance for a Green Energy Economy (AGREE), October 22nd, 2018.

for the projects. The lack of anchor tenants caused by the inability of demand rate customers to effectively participate in CDG thereby has the unnecessary effect of raising soft costs for CDG projects. The Community Credit rectifies this problem.

Pending costs may require the community credit to be adjusted upwards in the coming year

The modifications put forward in the Staff Capacity Paper are expected to make projects viable in places where there has been limited development to date (e.g., National Grid's service territory. We appreciate the modifications made to keep the market moving forward. However, we note that projects costs may increase due to a number of factors beyond a solar firm's control and thereby may require an increase in the community credit at some future point.

Expected increases in labor costs, as well as rising property taxes and interconnection costs in some part of the state, also provide an impetus for further cost reductions that can be achieved through already identified measures, such as consolidated billing, but also new innovations such as inter-utility crediting. The creation of the Community Credit reduces pressures on the residential rate class rate impact cap and (as described below) projects with MTC allocations failing to become operational and thereby releasing MTC capacity both create space within the rate impact limitations to allow for a higher credit.

Projects allocated pre-July 2018 MTC tranche allocations should be allowed to participate in the Community Credit

CEP recommends that projects making 25% interconnection payments before July 26 also be allowed the option of simply opting into the entire new Community Credit approach while retaining their current tranche allocation. In some cases, CDG sponsors seeking to encourage anchor tenants to subscribe to their projects may find the Community Credit approach a more flexible or attractive option than the MTC plus anchor tenant approach, and this option should reduce costs for ratepayers.

On the latter point, CEP expects that Staff's proposed changes, as well as our proposal to allow earlier projects to opt into the Community Credit approach, will reduce the number of subscribers receiving the full MTC, thus reducing the rate impact of the MTC significantly over time. In addition, project attrition—such as that already seen in many parts of the state—will also reduce the rate impact of the MTC below the Commission's original expectation.

For this reason, we recommend that staff periodically review the usage of the MTC—including attrition of projects that previously secured an MTC and the conversion of projects from MTC to Community Credit—and consider adding additional capacity in the Community Credit tranches to reflect the lower-than-expected rate impact of the original MTC.

The full value of the DRV and community credit should be allowed to roll over month to month on generator accounts and be allocated to subscribers

Currently, CDG projects that are not fully subscribed are able to bank any credits that are unallocated each month. Per the September 2017 VDER Implementation Order, the value of banked credits is based on the Value Stack in the month these credits are generated and does not include the Market Transition Credit (MTC). Banked credits are carried forward as monetary credits and can be allocated to subscribers in future months. The VDER Implementation Order states that the "value of each banked credit should be calculated by the utility based on the Value Stack in the month in which it is generated, including the

DRV but not including any MTC. The banked credits should be carried forward as dollar-value credits, rather than kWh credits."[13]

Presumably the reason that the value of banked credits does not include the MTC is because those credits could be allocated to non-MTC-eligible subscribers in future months. However, with the creation of the community credit and anchor tenant credit rate, both demand rate and non-demand rate customers are eligible for the full VDER stack, inclusive of both DRV and Community Credit or anchor credit.

CEP requests a clarification that projects that receive a Community Credit be able to bank the full value of any unallocated credits (including the Community Credit and Anchor Credit). Since the Community Credit is applicable to all subscribers (regardless of rate class), the issue that the value of a banked MTC could potentially be allocated to a subscriber that is not in an MTC-eligible rate class has been removed.

VI. APPLICATION OF PHASE ONE NEM TO BELOW 750 KW_{AC} ONSITE PROJECTS NOW AND BEYOND JANUARY 2020

Staff proposes that Phase One NEM be available for projects that are 750 kW_{AC} or smaller, are located behind the same meter as the customer, and have an estimated annual output of no more than the customer's historical usage. This would apply to all projects who qualify before January 1, 2020, and Staff will consider whether to extend Phase One NEM beyond January 1, 2020.

CEP strongly supports the application of Phase One NEM to these customers now and beyond January 1, 2020. Currently demand-metered customers who wish to offset a portion of their load using DERs must seek project funding based on variable Value Stack compensation. Net metering provides a much more stable and simple compensation mechanism that will help support DERs for this market segment.

VII. SUMMARY OF RECOMMENDATIONS

Staff's Whitepaper contains numerous proposed changes to the Value Stack that will better align the value provided by DERs with compensation, and will support higher rates of deployment of DERs. These changes are necessary to continue moving New York towards its renewable energy goals, including the target of 6 GW_{AC} of distributed solar. We propose a handful of modifications to Staff's proposals to avoid unintended consequences, improve the accuracy of the compensation mechanisms, and improve the customer experience. Our recommendations are summarized below.

1. We recommend that the changes to the DRV and Community Credit be swiftly adopted in order to bring greater certainty to the market.

2. We agree that the energy efficiency marginal cost values should be adopted for the DRV, but continue to support the development of robust, transparent marginal cost values through an adequate stakeholder process going forward.

[13] VDER Implementation Order, pp. 33-34

3. We support Staff's proposal to include 200+ hours in the DRV performance period, as it more accurately represents how utilities plan their distribution system to meet peak loads and will support the deployment of additional DERs.

4. CEP recommends that the DRV peak period begin on June 1. We also urge maintaining the 2 pm – 7 pm peak period, as it is the most accurate reflection of the current data and likely future trends, and it provides stronger incentivizes for resources that can generate later in the day (such as storage-paired solar and solar arrays with tracking systems). However, to encourage some systems to continue to reduce early afternoon peaks, we recommend that Staff also create a 1 pm – 6 pm peak window option for systems to opt into.

5. If the 1 pm - 6 pm proposed peak period is kept, CEP requests that systems that have already submitted their 25% interconnection payments be allowed to opt into the June 1 – August 31, 2 pm – 7pm peak period proposed in the July Staff whitepaper, as these systems may have been designed to maximize production during the later hours based.

6. CEP recommends clarifying that the DRV value will be part of the value stack bill credits transferred to customers. In addition, CEP strongly recommends that host accounts be able to allocate DRV credits to benefiting accounts evenly over the course of the year, even if these credits are accrued during the summer peak hours.

7. CEP supports the ability of dispatchable resources to opt into a demand response program with a forward-looking call signal.

8. CEP supports the extension of the DRV compensation period to 25 years, as it aligns with the time period over which DERs will be providing distribution services to the grid; i.e., 25 years.

9. CEP recognizes that Staff's 5% collar proposal would provide stability, but we are concerned that the DRV value could deviate substantially from the MCOS results in the future. Therefore, we propose that stakeholders be permitted to request a reset of the DRV if the results of the MCOS studies reveal that the true value should be significantly higher.

10. CEP is generally supportive of the LSRV phase-out, with projects instead receiving compensation through NWAs and demand response programs. However, we emphasize that this intensifies the pressure on the NWA process. In order to improve communication and transparency regarding the NWA process, we recommend that a stakeholder Distribution Planning Advisory Group be established in New York.

11. CEP strongly supports Staff's proposal that all customers of new CDG projects in National Grid, NYSEG, and RG&E's territories receive a Community Credit of $0.0225/kWh. CEP also supports the inclusion of the 1 cent/kWh anchor-tenant credit as a measure to encourage more mature CDG projects that already have tranche allocations to seek anchor tenants.

12. CEP recommends that projects making 25% interconnection payments before July 26 also be allowed the option of simply opting into the entire new Community Credit approach while retaining their current tranche allocation.

13. CEP requests a clarification that projects that receive a Community Credit be able to bank the full value of any unallocated credits (including the Community Credit and Anchor Credit). Since the

Community Credit is applicable to all subscribers (regardless of rate class), the issue that the value of a banked MTC could potentially be allocated to a subscriber that is not in an MTC-eligible rate class has been removed.

14. CEP strongly supports the application of Phase One NEM to customers with onsite DERs at or below 750 kW now and beyond January 1, 2020.

Thank you.

Respectfully submitted,

/s/

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