STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of the Value of Distributed Energy Resources	))	Case 15-E-0751

JOINT UTILITIES REPLY TO COMMENTS ON STAFF WHITEPAPERS ON FUTURE VALUE STACK COMPENSATION, CAPACITY VALUE, AND STANDBY AND BUYBACK SERVICE RATE DESIGN

The New York State Department of Public Service Staff ("Staff") filed the *Whitepaper Regarding Future Value Stack Compensation, Including for Avoided Distribution Costs* (the "Value Stack Whitepaper"), the *Whitepaper on Standby and Buyback Service Rate Design and Residential Voluntary Demand Rates* (the "Standby and Buyback Service Rates Whitepaper"), and the *Whitepaper Regarding Capacity Value Compensation* (the "Capacity Whitepaper")[1] in December 2018 (collectively, the "Whitepapers"). In response,[2] Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc. ("Con Edison"), New York State Electric & Gas Corporation ("NYSEG"), Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (collectively, the "Joint Utilities") along with other parties filed comments on February 25,

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1 Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources* ("VDER Proceeding"), Whitepaper Regarding Future Value Stack Compensation, Including for Avoided Distribution Costs (filed December 12, 2018)("Value Stack Whitepaper"), Whitepaper on Standby and Buyback Service Rate Design and Residential Voluntary Demand Rates (filed December 12, 2018)("Standby and Buyback Service Rates Whitepaper"), and Whitepaper Regarding Capacity Value Compensation (filed December 14, 2018)("Capacity Whitepaper").

2 VDER Proceeding, Notice Soliciting Comments on Staff Whitepapers (issued December 21, 2018)("Notice"). The Notice invited parties to file separate or combined comments by February 25, 2019.

2019.[3] The Joint Utilities respectfully request that the Commission consider these brief reply comments in response to statements and recommendations presented by other parties.

I. Introduction

The Joint Utilities continue to support New York State's efforts to design and offer rate structures and compensation mechanisms that support the cost-effective development and use of distributed energy resources ("DER"). When designed to incorporate appropriate locational and temporal price signals, these mechanisms can encourage the development and use of DER in ways that benefit the electricity system and thereby all customers. The Alliance for a Green Economy ("AGREE") states that "[g]etting VDER right is critical to the success of … REV."[4] The Joint Utilities agree.

In the context of the Whitepapers, the Joint Utilities agree with other stakeholders that support the Commission's efforts to establish more granular and locational pricing. The Advanced Energy Economy Institute ("AEE Institute"),[5] the Clean Energy Parties ("CEP"),[6] and the New York Battery and Energy Storage Technology Consortium, Inc. ("NY-BEST")[7]

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3 VDER Proceeding, Joint Utilities Comments on New York State Department of Public Service Staff Whitepaper on Regarding Future Value Stack Compensation Including Avoided Distribution Costs and Capacity Value Compensation ("Joint Utilities Value Stack Comments") and Joint Utilities Comments on New York State Department of Public Service Staff Whitepaper on Standby and Buyback Service Rate Design and Residential Voluntary Demand Rates ("Joint Utilities Standby Comments") (both filed February 25, 2019).

4 VDER Proceeding, Comments on the "Whitepaper Regarding Future Value Stack Compensation, Including for Avoided Distribution Costs" by Alliance for a Green Economy (filed February 25, 2019)("AGREE Comments"), p. [2].

5 VDER Proceeding, Comments on Staff Rate Design White Papers by Advanced Energy Economy ("AEE") Institute on behalf of Advanced Energy Economy, the Alliance for Clean Energy New York, and the Northeast Clean Energy Council (filed February 25, 2019)("AEE Institute Comments"), pp. 7, 9.

6 CEP is comprised of the Solar Energy Industries Association, the Coalition for Community Solar Access, the Natural Resources Defense Council, the New York Solar Energy Industries Association, Pace Energy and Climate Center, and Vote Solar. *See* VDER Proceeding, Comments on Whitepaper Regarding Future Value Stack Compensation, Including Avoided Distribution Costs (filed February 25, 2019)("CEP Value Stack Comments"), pp. 2-4.

7 VDER Proceeding, Whitepaper Regarding Capacity Value Compensation; Whitepaper Regarding Future Value Stack Compensation, Including for Avoided Distribution Costs; and Whitepaper on Standby and Buyback

emphasize the importance of retaining granular price signals as the DER market continues to grow, raising various concerns that the Whitepapers' proposals may erode or eliminate these price signals. For example, both Acadia Center[8] and CEP[9] echoed the Joint Utilities' concern that the proposed Demand Reduction Value ("DRV") "adjustment collar" would likely prevent DRV from reflecting actual avoidable costs.[10] Likewise, the Joint Utilities agree with Acadia Center that eliminating the Locational System Relief Value ("LSRV") is a step backward from the goals the Commission established for VDER because it undermines the Joint Utilities' ability to send accurate locational price signals to the market.[11]

The Joint Utilities also agree with NY-BEST's observations that the modifications proposed in the Whitepapers would "improve the VDER Value Stack tariff for small intermittent resources seemingly at the expense of responsive dispatchable resources."[12] Both NY-BEST and CEP agree that the Whitepapers' proposals would create an inappropriate disincentive for solar + storage projects, as well as tracking and west-facing solar panels, despite the fact that these types of resources can provide greater value to the electricity system and all customers. The Joint Utilities respectfully disagree with commenters that assert that the VDER framework has "failed" to animate DER markets.[13] As noted in their initial comments, the Joint Utilities offer that more than 5,000 MW of new DER projects have entered utility interconnection queues

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Service Rate Design and Residential Voluntary Demand Rates, by the New York Battery and Energy Storage Technology Consortium, Inc. ("NY-BEST Comments"), pp. 9-10.

8 VDER Proceeding, Acadia Center Comments, pp. 1, 3.

9 VDER Proceeding, CEP Value Stack Comments, pp. 8-9.

10 The Joint Utilities do not, however, agree with CEP's argument in response to the Standby and Buy Back Whitepaper (pp. 3-4) that time-varying volumetric rates provide better price signals for delivery costs. *See* VDER Proceeding, CEP Standby Comments, p. 3.

11 VDER Proceeding, Acadia Center, pp. 2-4.

12 VDER Proceeding, NY-BEST Comments, p. 15.

13 *See* VDER Proceeding, AGREE Comments, p. 3; *see also* VDER Proceeding, Energy Democracy Alliance VDER Comment ("Energy Democracy Alliance Comments"), p. 1.

across the State since the Commission's issuance of the VDER Phase One Order.[14] Many of these projects are currently under construction.

II. DRV

The Joint Utilities emphasize the importance of aligning DRV compensation with distribution value provided by DER resources. Other parties express similar concerns, in particular with the Value Stack Whitepaper's selection of a fixed set of hours to derive DRV compensation that may not match distribution system peaks. For example, the CEP presents an analysis demonstrating that system peaks in recent years do not fit neatly within the Value Stack Whitepaper's proposed 240-hour window.[15] The Joint Utilities note that distribution peaks can be markedly different from statewide peaks, but generally agree with CEP's findings that a static set of hours for all utilities is not optimal.[16] The use of a fixed set of hours would certainly provide predictability but could lead to inefficient investments with long-term impacts (*i.e.*, 25 years) as peaks evolve. The AEE Institute properly notes this dynamic as well.[17] The Joint Utilities suggest that rather than exposing customers to long-term commitments that provide limited customer benefits, DRV compensation should be tied to DER production during each utility's service territory-specific peak hours. To the extent that the current 10 peak-hour

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[14] VDER Proceeding, Order on Net Energy Metering Transition, Phase One Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017).

[15] VDER Proceeding, CEP Value Stack Comments, p. 6.

[16] *Id*. *See also* VDER Proceeding, AEE Institute Comments, pp. 4-6, where the AEE Institute similarly examines the pattern of peak hours in the New York Independent System Operator ("NYISO"), finding that they are shifting later. However, the Joint Utilities maintain that DRV should reflect distribution system value and the timing of associated peaks rather than state-wide bulk-loading. *E.g.*, NYSEG is partially a winter-peaking system, indicating that a statewide approach would be unable to properly reflect peak conditions throughout its service territory.

[17] *See* note 16 *supra*.

window creates more volatility than is deemed necessary to support development of eligible resources, a modest expansion to 50 hours may be appropriate.[18]

The AEE Institute's suggestion that resources could select the peak period for permitting this would further separate compensation for resources from the value they provide to the distribution system.[19] The DRV should be constructed to capture system conditions rather than resources' preferences. For example, the AEE Institute notes that "a MW of storage output from 6-7 pm will be far more valuable to the future system than a MW from 2-3 pm, when solar is near its peak output."[20] This is true for all resources, and not just a particular class of resource such as storage or solar.

CEP also advocates for modifying the Value Stack Whitepaper's DRV proposal to provide level credits throughout the year.[21] This recommendation actually reflects the approach used today within the current DRV methodology. This is because the existing DRV mechanism, like the LSRV and Alt 3 capacity mechanisms, already provides consistent monthly credits based on the prior year's actual performance. Thus, retaining the current mechanism either as is, or with a modest expansion of the number of performance hours, better aligns compensation with the actual value of the DER production while also providing the even credits supported by CEP.

Several stakeholders recognize that a key to reflecting value over time is updating the factors that determine the DRV to reflect their true values, which can shift from year to year in response to a variety of factors. In contrast, the Value Stack Whitepaper recommends a

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[18] Any increase in the window above 50 hours is unlikely to capture hours that reflect the greatest strain on the distribution system.

[19] VDER Proceeding, AEEE Institute Comments, p. 4. *See also* VDER Proceeding, CEP Value Stack Comments, p. 7.

[20] VDER Proceeding, AEE Institute Comments, p. 4.

[21] VDER Proceeding, CEP Value Stack Comments, p. 7.

mechanism to constrain the ability to make adjustments to reflect true value in price signals.[22] For example, CEP states that providing only a five-percent adjustment collar every two years on the DRV "could cause compensation to deviate substantially from the actual value provided by resources."[23] The Joint Utilities agree. Collars can distort price signals resulting in either over- or under-compensation. If the proposed collars are not eliminated entirely, they should be greatly expanded to the higher of $10/kw-year or 20 percent to allow better alignment of compensation with value provided over time. Restricting collar adjustments to small amounts exposes customers to the unnecessary risk of paying for value that resources do not provide or, in the alternative, provides DER compensation that is lower than the value provided.

The Joint Utilities disagree with the CEP proposal to restrict adjustments to the DRV to those that benefit DER, *i.e.*, by allowing only upward adjustments of the DRV to exceed five percent.[24] This position is inconsistent with the Commission's statement that "[a]ccurate price signals must apply both to the rates paid by customers and the value received in return for DER services."[25]

The AEE Institute recommends that the Commission revise the DRV to make it a payment to customers rather than a bill credit.[26] The Joint Utilities note that the community solar construct was designed to provide residential customers access to solar power and its benefits, not to provide a revenue mechanism for DER developers. Furthermore, because VDER Value Stack is a successor to net energy metering ("NEM"), it would be a gross distortion to

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22 VDER Proceeding, Value Stack Whitepaper, pp. 7-8.

23 VDER Proceeding, CEP Value Stack Comments, p. 8.

24 *Id*., pp. 8-9.

25 Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* ("REV Proceeding), Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016), p. 125.

26 VDER Proceeding, AEE Institute Comments, p. 5.

transition it into an outright payment rather than a bill credit. The Joint Utilities recommend that this AEE Institute's proposal be rejected.

Finally, NY-BEST recommends that the Commission direct the Joint Utilities to separately meter battery generation for Commercial System Relief Program ("CSRP") compensation for both self-consumption and exports.[27] While the Joint Utilities agree that there is value to separately metering the battery, providing CSRP compensation for self-consumption would result in overcompensation due to double-counting, as normal self-consumption already provides the customer with a distribution benefit by avoiding demand charges.[28] In order to protect other customers from additional costs, it would be necessary to establish rules to extend CSRP to compensate for incremental exports akin to existing CSRP baselines to assure there is no duplicative compensation.

III. LSRV

The Joint Utilities and NY-BEST agree that "a granular valuation (locational and temporal) of DERs"[29] is crucial to establishing the value that DER provide to the system, and that "mechanisms are needed to compensate those values."[30] Staff has also initiated the Market Design and Integration Working Group ("MDIWG") to explore how the benefits provided by DER might be compensated through a distributed system platform.[31] The Value Stack Whitepaper's proposal to eliminate the LSRV is inconsistent with the MDIWG charge and until that work is completed the LSRV should be retained to maintain the link between the value of

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27 VDER Proceeding, NY-BEST Comments, p. 8.

28 It is for this reason that CSRP uses a baseline to establish the compensation for these resources.

29 *See, e.g.*, VDER Proceeding, NY-BEST Comments, p. 8.

30 *Id*.

31 Cases 18-E-0130 *et al.*, *In the Matter of the Energy Storage Deployment Program*, Letter to Secretary Kathleen H. Burgess from Bridget Woebbe, Assistant Counsel Department of Public Service Staff (filed March 12, 2019).

DER and the compensation paid for that value. Further, NY-BEST noted that "[w]hile we agree with Staff that the current LSRV compensation mechanism is imperfect, we are concerned that eliminating it in its entirety, and instead relying on the equally imperfect DSIP process, NWAs, and Demand Response programs to fill this need, will not help build a robust DER market and will not maximize the system benefits of DERs."[32] While believing that non-wires solutions ("NWS") and demand response programs are more efficient mechanisms for avoided distribution system cost compensation than any tariff-based mechanism, the Joint Utilities agree with NY-BEST that NWS are unlikely to fully meet the need for locational price signals if DER developers have the option of instead receiving payments through a 25-year tariff mechanism that provides for above-market compensation with minimal performance requirements.

IV. MTC / Community Credit

Multiple Intervenors ("MI") [33] and Nucor Steel Auburn, Inc. ("Nucor")[34] agree with the Joint Utilities that additional bill impacts on customers should be limited and that subsidies not linked to specific value contributions are inappropriate. Nucor states the change of the MTC to a Community Credit was "ill-advised" because it "distorts the purpose in establishing an MTC in the first place."[35] Nucor further recommends "adherence to both the 2% net revenue impact cap as well as the hard MW cap that has been established to limit the impacts of MTC compensation to non-participants."[36] The Joint Utilities agree.

32 *Id*.
33 VDER Proceeding, Comments of Multiple Intervenors (filed February 25, 2019)("MI Comments"), p. 3.
34 VDER Proceeding, Comments of Nucor Steel Auburn, Inc. on Whitepaper Regarding Future Value Stack Compensation, Including for Avoided Distribution Costs (filed February 25, 2019), p. 2.
35 *Id*.
36 *Id*.

The CEP suggests that moving some MTC compensation to the DRV via the Community Credit mechanism will reduce impacts on customers.[37] As the Commission described, however, the MTC already includes distribution value: "The MTC is intended to subsume the values the DRV represents."[38] Thus, allowing subscribers to receive both a Community Credit and the DRV will not reduce impacts on customers. Such a new approach will in fact increase costs to customers because a combined Community Credit and DRV will in some cases result in higher overall compensation than the MTC.[39]

The City of New York advocates for a higher MTC for Con Edison.[40] This proposal is not necessary because in addition to the 18 MW of projects that are identified in Tranche 0/1 as of March 1, 2019, Con Edison's interconnection queue contains an additional 84.7 MW of eligible projects including 42.5 MW of fuel cell projects. Because fuel cells are expected to operate at capacity factors in excess of 90 percent and achieve a high coincidence with the DRV and, where applicable, the LSRV, the 42.5 MW of fuel cells will have the same cost impact as roughly 255 MW of solar installations.[41] This level of pending activity demonstrates that an increase in Con Edison's MTC is not required to spur DER development.

Furthermore, several stakeholders recommend that the Commission revisit its policy concerning the extension of the MTC to master-metered buildings.[42] The Commission has

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37 VDER Proceeding, CEP Value Stack Comments, p. 12.

38 VDER Proceeding, VDER Phase One, p. 124.

39 In considering these reply comments, the Joint Utilities realized that Attachments A-F of their initial comments do not reduce MTC subsidies by the distribution value. This is an oversight that should be corrected if the models are to be used in further decision making.

40 VDER Proceeding, Comments of the City of New York on Value Stack and Standby/Buyback Whitepapers (filed February 25, 2019)("City of New York Comments"), pp. 2-4.

41 A base-loaded fuel cell will have a capacity factor in excess of 90% which is six times the anticipated 15% capacity factor of solar in Con Edison's service territory.

42 *See, e.g.*, VDER Proceeding, AGREE Comments, Energy Democracy Alliance Comments, and City of New York Comments.

already rejected this issue.[43] These stakeholders offer no new or compelling evidence to warrant any further reconsideration of an established policy. Similarly, the Office of General Services argues that behind-the-meter generation should also be eligible for Value Stack compensation.[44] This proposal should be rejected as customers using generation to offset their usage are already avoiding distribution and energy charges.

Finally, the Joint Utilities reiterate their opposition to the creation of the Community Credit described in the Value Stack Whitepaper.[45] If, however, the Commission orders the creation of the Community Credit mechanism within the Value Stack, the Joint Utilities oppose MI's recommendation that its costs be allocated only to residential customers.[46] If MI's proposal were to be accepted, residential customers would pay for credits provided to large commercial and industrial customers. Instead, the Community Credit should be allocated using the same methodology as the MTC (*i.e.*, to those customer classes that receive it).

On a final note related to Value Stack, CEP's suggestion that the Commission institute a Distribution Planning Advisory Committee[47] should be rejected. Such a committee is unnecessary and would duplicate the existing Distributed System Implementation Plan ("DSIP") Advisory Committee,[48] creating an additional burden on stakeholder resources by creating yet

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43 VDER Proceeding, Order Denying Petition for Rehearing and Making Other Findings (issued October 24, 2017).

44 VDER Proceeding, Comments of the New York State Office of General Services on Whitepaper Regarding Future Value Stack Compensation, Including for Avoided Distribution Costs (filed February 25, 2019), pp. 1-3.

45 VDER Proceeding, Joint Utilities Value Stack Comments, pp. 17-19.

46 VDER Proceeding, MI Comments, pp. 7-8.

47 VDER Proceeding, CEP Value Stack Comments, p. 10.

48 The DSIP Advisory Committee is composed of Joint Utilities' representatives as well as outside stakeholders. Its purpose is to address pertinent DSIP matters and to conduct stakeholder processes to help the public better understand among other things the distribution planning process, NWS suitability criteria and the application of the BCA to distribution planning decisions. In fact, there have been and continue to be numerous opportunities for stakeholders to provide input on policies related to utility plans to implement programs that promote clean energy solutions in New York.

another working group. The CEP's recommendation fails to recognize existing stakeholder outreach that occurs in the DSIP proceeding and other forums[49] as well as through existing quarterly reporting on NWS solicitations. Finally, CEP's reference to California[50] is inapt as that state is on a different evolutionary path to providing locational value and, has not yet implemented any NWS.

V. Capacity

The AEE Institute notes that peak demands evolve over time and that a set of defined hours may discourage investment in technologies that could provide significant system benefits by removing their incentive to be available when system requirements are the greatest.[51] The AEE Institute further notes: "While no ICAP hours have fallen from 7-8 pm, the data is clearly trending toward a later peak than an earlier peak… As solar penetration increases, shifting some of the solar production to later hours through storage or tracking systems will become increasingly valuable and will slow the development of a Duck Curve in New York."[52]

The CEP proposes that the Capacity Value credit include excess demand curve volume.[53] While the NYISO's rules increase the reserve requirement that all load serving entities have to meet based on excess capacity purchased under the application of the demand curve during each month's Spot Auction, that excess does not increase the capacity payment made to any individual generation resource nor would it be avoidable if the year over year peak load was decreased, which is the net effect of VDER injections coincident with the New York Control

49 In 2016 and 2018 each utility hosted stakeholder engagement sessions to inform the preparation of DSIP filings. In these sessions, developers and third-party participants were offered the opportunity to ask clarifying questions and provide input into the DSIP filing process.
50 VDER Proceeding, CEP Value Stack Comments, p. 10.
51 VDER Proceeding, AEE Institute Comments, p. 2.
52 *Id.*
53 VDER Proceeding, CEP Capacity Value Comments, pp. 7-9.

Area peak. Therefore, while the excess capacity is a cost to load, it is not avoidable from a decrease in aggregate load.

VI. Standby and Buyback Service Rates

The Joint Utilities agree with the City of New York[54] and NECHPI[55] statements that expansion of Rider Q's granular as-used demand charge pilot is premature at this time. It will be more appropriate to consider expanding that program after gaining additional experience from a broad group of customers. In addition, the Joint Utilities agree with Consumer Power Advocates[56] that marginal cost approaches to standby rate design should not be rejected.

The CEP acknowledges that the Standby and Buyback Service Rates Whitepaper proposes that the Commission require the utilities in New York to adopt opt-in demand rates for mass market customers.[57] However, CEP goes on to state that it "strongly opposes mandating demand charges for mass market customers which would represent a significant shift in rate design in New York."[58] The CEP then discusses what it perceives to be negative impacts of mandatory demand charges.[59] This is a misinterpretation of the proposal; the Standby and Buyback Service Rates Whitepaper does not propose mandatory demand charges.

In addition, CEP claims that demand rates for mass market customers are not cost based.[60] The Joint Utilities disagree. Electric delivery rates must recover the costs associated with an electric grid that is designed, built, and maintained to reliably serve customers based on

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54 VDER Proceeding, City of New York Comments, p. 12.

55 VDER Proceeding, NECHPI Comments, (filed February 25, 2019) by Northeast Clean Heat and Power Initiative ("NECHPI Comments"), p. 2.

56 VDER Proceeding, Consumer Power Advocates Comments, (filed February 25, 2019), pp. 3-4.

57 VDER Proceeding, CEP Standby Comments, p. 3.

58 *Id.*

59 *Id.*

60 *Id.*, p. 4.

demands at the customer, local, upstream, and bulk power system levels. This means that demand (measured in kilowatts or "kW") at these various levels forms the basis for system design criteria, construction, and maintenance. Once the system is built and maintained to serve a given level of demand, any volume of energy (measured in kilowatt-hours or "kWh") up to that kW design level can flow through the system without having a material impact or creating new costs. Therefore, demand rates are in fact cost based – and indeed more reflective of cost causation than volumetric rate structures. The CEP later states that "the Commission should recover demand driven costs on an hourly basis through energy charges" and claims that this approach is superior on a cost causation basis.[61] The recovery of demand-driven costs through energy charges does not reflect cost causation. Furthermore, it would perpetuate the misalignment of costs and recoveries in mass market electric delivery rates and contribute to inefficient DER investment.

The Standby and Buyback Service Rates Whitepaper recommends that the Commission direct utilities other than Con Edison to develop and file a Multi-Party Campus Offset Tariff similar to that currently in place at Con Edison.[62] A Multi-Party Campus Offset Tariff allows the energy usage of multiple customers in multiple buildings to be offset by a common generator, provided that such customers are located on the same premises and are connected to the generating facility via a thermal loop. The City of New York,[63] the New York Power Authority,[64] NY-BEST,[65] Digital Energy Corporation,[66] and NECHPI[67] all propose that the

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[61] *Id.*., pp. 6-7.
[62] VDER Proceeding, Standby and Buyback Service Rates Whitepaper, p. 13.
[63] VDER Proceeding, City of New York Comments, pp. 13-14.
[64] VDER Proceeding, Comments of the New York Power Authority (filed February 25, 2019), pp. 1-2.
[65] VDER Proceeding, NY-BEST Comments, p. 11.
[66] VDER Proceeding, Comments of the Digital Energy Corporation (filed February 25, 2019), pp. 2-3.
[67] VDER Proceeding, NECHPI Comments, pp. 2-3.

thermal loop requirement be eliminated. The Joint Utilities oppose proposals to eliminate this requirement because it is necessary to ensure that customers are proximate to the generating facility. Elimination of this provision and adoption of proposals to permit offset for customers served from a common substation, network, or CSRP zone could enable customers who are not proximate to the generating facility to obtain the offset, in effect extending the applicability of remote net metering to CHP.

NECHPI also recommends that the reliability credit be expanded to as-used demand charges.[68] The Joint Utilities also oppose this proposal because, as explained in the Joint Utilities' Comments, the reliability credit should be phased out or eliminated. The current reliability credit mechanism can result in customers receiving compensation for reasons other than generator performance.[69] The Joint Utilities urge the Commission to consider modifying the reliability credit to focus on generator performance or eliminate it entirely and base compensation on measured generator output to assure reliable operation.[70]

The Joint Utilities agree with the Utility Intervention Unit[71] that Standby and Buyback Service Rates may be challenging for some customers to understand, and that a deliberate process for introducing these rates would be beneficial. In earlier comments the Joint Utilities emphasized "the importance of designing demand-based rates that mass-market customers can understand and to which they can reasonably respond. Offering complex rates from the

68 *Id*., p. 2.
69 REV Proceeding, Initial Comments of the Joint Utilities on the July 28, 2015 Staff White Paper on Ratemaking and Utility Business Models (filed October 26, 2015), pp. 49-50.
70 In making this request, the Joint Utilities acknowledge that the Commission had declined to reconsider their request to model the Reliability Credit on Con Edison's Performance Credit. REV Proceeding, Order Denying Petition for Reconsideration (issued December 15, 2016).
71 VDER Proceeding, Comments of the Utility Intervention Unit (filed March 12, 2019), p. 2.

beginning, like the standby rates currently applicable to C&I [commercial and industrial] customers…may discourage mass-market customer participation."[72]

VII. Allowing C&I to Participate in Net Energy Metering

The Joint Utilities agree with the perspectives shared by MI with respect to the expansion of access to NEM to small, demand-billed commercial customers.[73] The expansion of NEM to smaller, demand-billed commercial customers should be adopted because NEM coupled with a demand rate structure not only provides appropriate prices signals regarding the costs such customers impose on the system, but also avoids the potential for significant cost shifts and bill impacts for non-participants.

VIII. Conclusion

The Joint Utilities appreciate the Commission's consideration of these responses to various stakeholder comments on the Whitepapers and look forward to working with Staff and other stakeholders to advance policies through the VDER Proceeding that will lead to cost-effective deployment of clean energy resources for the benefit of all New York customers.

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[72] VDER Proceeding, Joint Utilities Standby Comments, p. 3.
[73] VDER Proceeding, MI Comments, pp. 4-6.

The Joint Utilities urge the Commission to adopt the recommendations enumerated in the Joint Utilities Value Stack Comments and Joint Utilities Standby Rates Comments.

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Respectfully submitted,

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