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August 27, 2018

VIA ELECTRONIC DELIVERY

Honorable Kathleen H. Burgess
Secretary
New York State Public Service Commission
Three Empire State Plaza, 19th Floor
Albany, New York 12223-1350

RE: Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources

JOINT UTILITIES COMMENTS ON DRAFT STAFF WHITEPAPER REGARDING VDER COMPENSATION FOR AVOIDED DISTRIBUTION COSTS

Dear Secretary Burgess:

In response to the July 26, 2018 filing by the New York State Department of Public Service Staff of the *Draft Staff Whitepaper Regarding VDER Compensation for Avoided Distribution Costs,* Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (collectively, the "Joint Utilities") hereby submit their initial comments and suggestions.

Respectfully submitted,

/s/ Janet M. Audunson

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Enc.

cc: Marco Padula, DPS Staff, w/enclosure (via electronic mail)
Warren Myers, DPS Staff, w/enclosure (via electronic mail)
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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

JOINT UTILITIES COMMENTS ON DRAFT STAFF WHITEPAPER REGARDING VDER COMPENSATION FOR AVOIDED DISTRIBUTION COSTS

I. Introduction

On July 26, 2018, New York State Department of Public Service Staff ("Staff") filed a *Draft Staff Whitepaper Regarding VDER Compensation for Avoided Distribution Costs* ("Draft Whitepaper")[1] and requested comments by August 27, 2018. The Draft Whitepaper proposes certain changes to the Value Stack compensation methodology to produce price signals that reflect the benefits provided by distributed energy resources ("DER") to the distribution grid. Staff intends to develop a final whitepaper that will be subject to a formal comment process prior to its consideration by the New York Public Service Commission. Please accept these initial comments and suggestions on behalf of 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").

[1] Case 15-E-0751, *In the Matter of Distributed Energy Resources* ("VDER Proceeding"), Draft Staff Whitepaper Regarding VDER Compensation for Avoided Distribution Costs ("Draft Whitepaper")(filed July 26, 2018).

II. Summary

The Draft Whitepaper focuses on changes to two elements of Value Stack compensation: (1) elimination of the locational system relief value ("LSRV") component, and (2) significant modifications to the demand reduction value ("DRV") component. Additionally, the Draft Whitepaper proposes an extension of Phase One Net Energy Metering ("NEM") for on-site projects that (a) have a rated capacity of 750 kW AC or lower; (b) are at the same location and behind the same meter as the electric customer whose usage they are designed to offset; and (c) have an estimated annual output less than or equal to that customer's historic annual usage in kWh.

The Joint Utilities support providing accurate price signals to customers and DER developers. DER compensation that differs to a meaningful degree from the value to the grid will result in either more or less DER than is optimal and produce increased costs for customers. The Joint Utilities agree that locational value is a critical consideration when compensating DER and support the Draft Whitepaper's conclusion that non-wires solutions ("NWS") provide more targeted and economically-efficient outcomes than the current LSRV component of the Value Stack. NWS are an efficient way to recognize and compensate DER, superior to any generic tariff approach. NWS enables the development of intermittent and dispatchable DER to meet specific locational and temporal needs of the grid. The Joint Utilities and their customers would benefit from the sunsetting of the LSRV and the preservation of the flexibility of NWS to provide value to the grid through tailored Requests for Proposals ("RFPs") that address grid requirements unique to a particular geographical location.

At the same time, the Joint Utilities recognize that DER may provide value to the grid at various locations and the DRV is intended to capture that value when there is no NWS. The

Joint Utilities suggest modifications to the DRV proposal in the Draft Whitepaper to improve the accuracy of price signals provided to intermittent resources with the goal of reducing overcompensation of these resources and costs to non-participating customers. Further, the Joint Utilities support using the Commercial System Relief Program ("CSRP") to compensate non-intermittent resources, eliminating the need for the Draft Whitepaper's proposed "Alternative 2."[2]

The balance of these comments focuses on the importance of proper determination of the DRV in order to provide accurate price signals. Of critical importance is the Draft Whitepaper's proposal to lock in the structure of DRV "Alternative 1"[3] for 25 years, over which time distribution load shapes and associated grid value are likely to change substantially. Experiences in California, Arizona, and Hawaii provide important insights into the need for flexibility as changing load shapes impact distribution requirements and the associated value of DER evolves.[4] For example, locking in a distribution value compensation formula for 25 years as proposed in the Draft Whitepaper's Alternative 1 in advance of the upcoming Market Design & Integration Report process, as announced in the *Department of Public Service Staff Whitepaper - Guidance for 2018 DSIP Updates*,[5] may hinder or undermine efforts to support the long-term sustainability of DER markets.

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2 *Id.*, pp. 7-8.

3 *Id.*, p. 7.

4 *E.g.*, California is already experiencing significant changes in load shapes in response to incentives that promote solar generation, commonly referred to as the "duck curve" phenomenon.

5 Case 16-M-0411, *In the Matter of Distributed System Implementation Plans*, Department of Public Service Staff Whitepaper – Guidance for 2018 DSIP Updates (filed May 29, 2018), pp. 4-5.

III. The DRV Should Approximate Actual Value to the Distribution System

The elimination of the LSRV increases the importance of setting the DRV at an appropriate level of compensation for DER distribution system value. While the Joint Utilities generally agree that a tariffed mechanism will fall short of capturing the more granular time- and location-based needs of the electric system, the DRV should still retain a structure that aligns with actual value to the system. To that end, the DRV should be based on the best and most recent available data and strive to reflect DER's value to the grid as accurately as possible. The Joint Utilities filed utility-specific marginal/avoided cost studies on July 31, 2018 that will provide the basis for setting the DRV.[6]

A. General DRV Comments

The Draft Whitepaper proposes to establish DRV compensation based on the average marginal/avoided cost over all hours of the year. The compensation would be based on the entire distribution system and would not distinguish between constrained and unconstrained areas. The Draft Whitepaper proposes that DRV estimates be updated no more frequently than every two years and in Alternative 1, constrains those changes to a 10 percent band (5 percent up or down). The Draft Whitepaper observes that this new methodology mirrors the approach used to evaluate utility energy efficiency programs.

The Joint Utilities are concerned that this methodology will overcompensate DER that is located in unconstrained areas, resulting in unnecessary, increased costs to non-participating customers without providing incremental benefits. This result is a simple function of the math behind calculating the average system-wide marginal cost. In order to avoid overcompensation under this approach, those resources in constrained areas would have to accept lower

6 Orange and Rockland Utilities, Inc. requested and was granted an extension to file its marginal cost study.

compensation than the value they provide to make up for those resources in unconstrained areas receiving higher compensation than the value they provide. The only way that the value of DER in a constrained area would provide accurate compensation would be if the DER is part of an NWS where the NWS compensation accurately reflects the value provided by participating DER.

The Draft Whitepaper would also allow DER currently receiving compensation under the Value Stack to opt in to the new DRV. In these cases, utility customers would be required to provide higher compensation for no incremental distribution system benefit. As a result, the DRV recommendations in the Draft Whitepaper, if not corrected, will overcompensate DER and increase costs to other customers.

To resolve these issues and preserve value for all customers the Joint Utilities propose:

- Basing the DRV on each utility's latest cost studies and establishing the DRV at a level that provides net distribution system benefits for all customers.
- Delaying the ability of existing resources to opt in to the new DRV until an assessment of the cost shift and resultant increase in rates for non-participating customers is estimated.
- Preventing double counting of distribution system value when performing NWS bid evaluations for consistent treatment of benefits and costs among NWS proposals. If a resource is otherwise eligible for DRV and participates in an NWS bid, it should either forego the DRV compensation or have the DRV considered as part of its NWS compensation to avoid overcompensating the resource.

B. DRV Alternatives

The Draft Whitepaper further contemplates that projects will be allowed to choose between two DRV alternatives as discussed below.

1. Draft Whitepaper Alternative 1

Under Alternative 1, marginal cost studies would estimate the average $/kW-year marginal distribution cost and convert it to a $/kWh rate applied to the 460 summer hours (*i.e.*, 2-7 PM, June-August) used for Capacity Value Option 2 under the Value Stack tariff. As described in the Draft Whitepaper, this approach provides specificity regarding the Staff draft proposal for the precise hours that qualify for the DRV (as compared to compensation that applies to ten peak load hours determined after-the-fact, which represents a smaller sample and varies with weather conditions). The DRV would be updated every two years throughout the 25-year compensation period but be restricted to varying by no more than +/- 5 percent per biennial update. Because all new resources would be subject to the then applicable DRV regardless of their interconnection date, it would no longer be necessary to track and compensate DRV based on vintage.

The Joint Utilities support Staff's goal to make the DRV less administratively burdensome by simplifying provisions regarding vintaging. However, the Joint Utilities have several concerns with certain aspects of proposed Alternative 1. The 460-hour compensation period is overly broad and as such increases the likelihood that the compensation period will not align well with the avoidance of capital infrastructure requirements driven by peak demand growth. In addition, with the expansion of the number of hours from 10 to 460, it is more probable that a resource could receive compensation during 90 percent of the proposed 460 hours and provide no distribution support at the time of the actual peak.

Further, establishment of a common 2-7 PM time period for all utilities may align with the current New York Control Area peak but will not always be aligned with individual utility distribution system peaks or with peaks associated with specific locations within the service territory of the same utility (*e.g.*, among Con Edison's four CSRP zones). Peak load hours may also occur outside of the three-month summer period. NYSEG, for example, experiences annual system peaks during the winter months. Further, the 2-7 PM period will need to be revisited during the 25-year term as loads shift in response to New York energy policies, as noted above. Providing DER the full DRV avoided cost compensation amount, while increasing the number of applicable hours, shifts DER performance risk from developers to utility customers. This in turn overcompensates participating projects because it does not adjust compensation value to account for the non-performance risk that is borne by customers. By proposing to lengthen the hourly compensation period to 46 times its original length and restricting it to a predefined season, the proposed Alternative 1 approach increases the likelihood that significant compensation will be awarded in certain circumstances even though the resource contributed minimally, or not at all, to the actual distribution need it is being paid to meet.

In addition to the proposed 460-hour compensation period, the hard, five percent limit on the change in the DRV payment every two years with no flexibility further exacerbates these issues. In an era with flat or declining load growth and modest peak increases, marginal or avoided distribution costs have the potential to vary by far more than 2.5 percent each year. Indeed, core inflation itself can vary in excess of that rate. This could easily result in significant over- or under-compensation of resources for an extended time period if future distribution marginal costs vary markedly from the initial marginal costs on which the DRV was set. For example, if the marginal cost estimate changed by 50 percent in year two and remained constant it would take over twenty years for the five-percent biennial adjustment factor to produce a DRV level reflecting the 50 percent change.

To address these concerns, the Joint Utilities suggest that Staff consider the following modifications to Alternative 1 in the Draft Whitepaper, supplementing the DRV proposals above that address locational value:

- Lock in the DRV for an initial five-year period when the assurance of revenues is most important to developers and lenders, addressing the desire to provide greater financeability for DER, with updates of the DRV every two years for the remainder of the 25-year period without any price constraint;
- Allow each utility to establish time windows for application of the DRV that are aligned with its distribution system needs; and
- Where appropriate to reflect changing load trends, allow utilities to modify these time windows in order to maintain a close connection between value provided by DER and compensation over time.

2. *Draft Whitepaper Alternative 2*

Under Alternative 2, which the Draft Whitepaper describes as designed primarily for dispatchable resources, the $/kW-year would continue to be spread over ten peak-load hours. Rather than determining these hours after the fact, compensation would be announced by a call signal issued 21 hours in advance of an event, similar to the CSRP.

Resources would receive compensation based on their performance during each of the ten hours. The basis for the call signal would be a forecasted event where the system nears 90 percent of its capacity. There would also be a provision for a minimum number of calls per year. To provide stability, Alternative 2 would fix the $/kW year for seven calendar years and be subsequently updated every two years.

The Joint Utilities believe that Alternative 2 could result in decreased resource participation in NWS if the NWS offers lower compensation and a shorter period of revenue certainty than seven years. Additionally, Alternative 2 would operate in parallel to each utility's existing CSRP, creating market confusion and the potential for arbitrage. Concerns regarding the accuracy of price signals can be addressed by having dispatchable resources directly participate in each utility's existing CSRP, which would mean that all projects are compensated based on the value they provide, and thereby eliminate the need for a duplicative program. Finally, the adoption of two DRV approaches would also create additional complexity for utility billing procedures associated with Value Stack compensation.

The Joint Utilities propose that all dispatchable DER would be automatically enrolled in the CSRP and an intermittent resource could make a one-time election to opt-in. This would provide all resources the ability to receive performance-based compensation linked to specific time and locational considerations. A provision for a minimum number of annual calls would not be appropriate because it would compensate projects when they are not relieving a distribution system constraint.

C. Financeability

The Joint Utilities support compensation methodologies that increase the ability of developers to finance their projects, however, the overall compensation should correspond to the value each project provides, giving an accurate price signal. There may still be evidence of market failures if, for example, developers are unable to finance projects targeting a specific market segment. However, NY Green Bank may provide solutions to address this matter. If NY Green Bank solutions are inadequate, it is likely to be more cost-effective to increase participation through utility ownership rather than artificially increase compensation to levels that overstate a resource's actual benefits.

D. Transition to Phase One NEM for Certain On-Site Projects

The Draft Whitepaper proposes that Phase One NEM be available for projects that (1) have a rated capacity of 750 kW AC or lower; (2) are at the same location and behind the same meter as the electric customer whose usage they are designed to off-set; and (3) have an estimated annual output less than or equal to that customer's historic annual usage in kWh. This recommendation would apply at a minimum to all projects that qualify before January 1, 2020 and would be for a 20-year term from each project's in-service date.

Although the Joint Utilities recognize the need for additional consideration in regard to extending Phase One NEM availability, the Joint Utilities support the Draft Whitepaper's goal to simplify the compensation mechanism for these projects through a rate design that is more aligned with cost causation.

IV. Conclusion

The Joint Utilities appreciate the opportunity to provide these comments in response to the Draft Whitepaper in advance of Staff's final whitepaper.

Dated: August 27, 2018

Respectfully submitted,

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