STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

CASE 15-E-0751 – In the Matter of the Value of Distributed Energy Resources.

Draft Staff Whitepaper Regarding VDER Compensation for Avoided Distribution Costs

(draft dated July 26, 2018)

INTRODUCTION AND BACKGROUND

On March 9, 2017, the New York State Public Service Commission (Commission) issued an Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (VDER Phase One Order). The VDER Phase One Order directed that the compensation for eligible distributed energy resources (DERs) transition from net energy metering (NEM) to the Value Stack. The Value Stack is a methodology that bases compensation on the actual, calculable benefits that such resources provide. Quantifying and compensating these benefits remains central to the Commission's overall strategy to move to an energy system that is cleaner, more affordable and increasingly resilient. Equally as important are the objectives of 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.

DERs subject to the Value Stack receive compensation for the energy they inject into the utility system for a set of values calculated based on the utility costs they offset: Energy Value, based on the energy commodity purchase offset by each kWh injected; Capacity Value, based on the ICAP purchase offset by injections; Environmental Value, based on the Clean Energy Standard (CES) compliance cost offset by each kWh injected; Demand Reduction Value (DRV), based on the distribution costs offset by injections, averaged across the utility's service territory; and Locational System Relief Value, (LSRV), available only in locations that the utility has identified as having needs that can be addressed by DERs, and based on the higher, specific distribution costs offset by injections in that area. Mass market customers participating in Community Distributed Generation (CDG) projects do not receive the DRV; instead, they receive the Market Transition Credit (MTC), an additional value designed to moderate the transition from net metering to the Value Stack.

For decades, the New York Department of Public Service has relied on utility marginal distribution capacity cost studies to estimate incremental/avoidable costs associated with Energy

Efficiency (previously called Demand Side Management or DSM) measures, in rate design deliberations, and, in more recent years, in designing demand response programs. In the VDER Transition Order, the Commission directed that these studies be used as the basis for identifying and calculating DRV and LSRV. The utilities were ordered to "de-average" these general marginal cost estimates by identifying LSRV areas, as well as LSRV values and capacity limits for those areas, and then calculating DRV by combining the costs not included in the calculation of an LSRV. This produced a $/kW-year value for each LSRV and for the DRV in each utility. In order to tie compensation to a relevant measure of resource performance, these values were allocated to the ten highest annual load hours for each utility; that is, the $/kW-year value is divided by ten to create a $/kWh value that resources earn for each kWh generated during those ten peak hours of the year. This credit is calculated annually, divided by twelve, and credited monthly. Table 1 contains the DRV values currently reflected in each utility's VDER Tariff.

Table 1. DRV Values per kW-Year and per kWh, for Top Ten Load Hours

	DRV					
	CHGE	O&R	NGRID	NYSEG	ConEd	RGE
$/kW-Yr	$6.00	$64.78	$61.44	$29.67	$199.40	$31.92
$/kWh--10	$0.60	$6.48	$6.14	$2.97	$19.94	$3.19

The VDER Phase One Order, including the Value Stack, has successfully encouraged the development of a large number of CDG projects designed to serve mass market customers. As noted, instead of compensation for DRV, these projects are eligible for an MTC as a transitional mechanism for in the move to VDER. However, in absence of an MTC value, developers have experienced difficulty planning projects where the DER is intended to serve a single large commercial customer whether onsite, through remote net metering, or as an anchor tenant in a CDG project. As these projects are not eligible for the MTC, it is prudent to consider the efficacy of DRV and its impact in creating a financially viable Value Stack tariff. A number of developers and other stakeholders have observed that the DRV and LSRV mechanisms are lacking the necessary certainty and predictability to structure projects under VDER policy that are not eligible for the MTC. In addition, some stakeholders have submitted specific critiques regarding technical aspects of the utility marginal cost studies, which provide the basis of those values.

The technical methods used in the utility marginal cost studies are not addressed in this Whitepaper for several reasons. Most significantly, as noted above, utility marginal cost studies are used for many purposes in addition to VDER compensation. For that reason, the technical aspects of distribution marginal cost estimation should be reviewed in a more generic setting. Further, these marginal cost study methodologies have been developed over many years and are being improved continuously. Staff agrees that continued improvement – and indeed planned and focused improvement – of marginal cost studies is a necessary and critical aspect of hastening the transition to an increasingly distributed grid. However, the appropriate forum for that improvement and associated deliberations is as part of utility Distributed System Implementation Plan (DSIP) filings. Utility DSIP filings include substantial discussion of utility costs and system data, particularly capital investment plans (driven largely by expected load growth) which are direct inputs to the marginal cost studies. Given that the next set of utility distribution marginal cost studies will be filed by July 31, 2018, in conjunction with utility DSIP filings, Staff recommends that, starting with these 2018 filings as a jumping off point, the biennial DSIP process be used as the primary venue for the review and improvement of these distribution marginal cost studies and other aspects related to quantifying distribution value associate with DER. For that reason, Staff will not conduct substantive review of the critiques of existing marginal cost studies in this document. Rather, a process for reviewing these studies will be developed once the latest studies are filed at the end of July in conjunction with the DSIP filings. Staff will ensure that all members of the Value Stack working group, as well as other interested stakeholders, have an opportunity to participate fully in this process and, following the process, to provide continued input on the appropriate use of the utility marginal cost studies for determining avoided distribution cost compensation.

This draft Whitepaper will instead focus on addressing aspects related to the function of the DRV and LSRV as compensation mechanisms for DERs, particularly large on-site projects and remote crediting projects.

SUMMARY OF STAKEHOLDER VIEWS

Through the Value Stack working group, Staff has worked with stakeholders to develop a common understanding of the marginal cost studies and to allow stakeholders to explain and discuss views, criticisms, and proposals related to the DRV and LSRV. Stakeholders also had the opportunity to make presentations and filings regarding their proposals and to respond to each other's proposals. This section briefly summarizes some of the issues discussed and proposals and responses made, focusing on those concerns and proposals that Staff recommends addressing at this time. The Value Stack working group is now also considering recommendations regarding refinements to the Environmental Value and proposals resulting from that process will be separately presented for more formal consideration later this year.

Some stakeholders posit that providing full marginal cost compensation to intermittent resources overcompensates these resources, inasmuch as they are not providing the specific, granular functionality and performance required to substitute for the utility investments upon which the marginal cost studies are based. By comparison, dispatchable resources are potentially able to meet these requirements but, some stakeholders believe, the DRV and LSRV mechanisms lack the commitment and control mechanisms necessary to allow utilities to consider them fully reliable. Further, it is argued, the Phase 1 approach is not coordinated well with other methods of compensating distributed resources for avoided distribution costs, specifically Non-Wires Alternative (NWA) solicitations and retail demand response (DR) programs.

Other parties have argued that the DRV and LSRV mechanisms are too complicated, unpredictable, and uncertain to support the development of many DER projects, such that developers and investors often significantly or entirely discount these values, thereby undermining the value proposition for a potential electric customer. In particular, they explain that the updating of DRV rates every three years, based on new marginal cost studies and without any guarantee as to the size of potential changes, means that the DRV rate cannot be used to plan for and secure investment for long-term assets. Furthermore, particularly for solar photovoltaic (PV) generators – which represent the vast majority of VDER resources – PV providers observe that using performance during each year's top ten load hours, determined after-the-fact to calculate compensation, results in a value stream that is too speculative for a PV developer to rely upon when deciding whether to incur any incremental investment to try to capture such value, as both the hours themselves and the generator's performance during those hours can be unpredictable. These stakeholders submit that most of the value-impacting decisions for PV are made at the time of planning, development, siting, and installation. While these decisions, such as orientation of the panels or use of trackers, can impact the generator's performance during peak hours in general when faced with a performance window of ten hours over the course of a year, the risk of underperformance due to factors like weather is too great to justify the investment that would otherwise result in added distribution value and therefore project compensation. This problem is exacerbated, it is argued, when the top ten hours differ by network within a utility territory, as it does in Con Edison's VDER tariff. Further, the argument continues, utility planning and investment (and thus avoidable distribution cost) is based on a multi-year forecast of future network peak load, not on any one year's actual top ten hours.[1]

Another concern raised was that, given the time constraints in Phase 1, the methods for "de-averaging" DRV value from LSRV value were more heuristic than sophisticated. Also, some parties felt that the method for determining the MW limits for each LSRV area was not sufficiently transparent.

In addition, some stakeholders expressed that the Value Stack compensation mechanism is not entirely well suited for customers seeking only to offset their usage with local generation, and that the DRV and LSRV components cause particular difficulty in developing such projects.

STAFF RECOMMENDATIONS

Considering all of the above, Staff believes that the current DRV and LSRV rules may represent an attempt to achieve greater granularity and precision than is reasonable under VDER Phase One and possible in an open, administratively-determined tariff mechanism. The desire to compensate for precise grid values must be balanced with the risk that a more sophisticated tariff may result in price signals that do not fully incentivize and motivate developers and customers to make decisions based on the objective of maximizing grid value.

In more competitive markets, the granularity and specificity required to meet particular, specific functional needs[2] is usually managed with individual procurements and contracts, rather than through generic commodity markets. The DSIP process has made significant progress in addressing many of these same issues in the context of specific NWAs, through which utilities employ market-enabling procurements with detailed functional requirements to offset the need to make particular distribution system investments. In Staff's view, the VDER tariff should be a supplement to, not an imitation of, the integrated planning, investment, and contracting process developed through the DSIP process and NWAs. However, Staff also recognizes that during this

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1 This is particularly true in a year that has very mild weather and de facto peak hours that happen to differ from those in a more typical year.

2 Especially with respect to long-lived assets, such as the avoided distribution investments that DRV and LSRV are intended to reflect.

period of transformation through which the grid is becoming increasingly distributed and bi-directional and DER technologies more prolific, there is value to continuing a tariff-based process for smaller, intermittent facilities that cannot economically participate in utility NWAs given their unique characteristics and market segments. When optimally designed and located, these resources will continue to allow utilities to avoid a certain amount of future infrastructure investment[3] and related O&M, and therefore it is appropriate a tariff-based mechanism to compensate for that. For those reasons, Staff proposes a change to the Value Stack distribution value compensation in order to leverage the strengths of a tariff-based mechanism for these resources. At the same time Staff observes that DSIP, NWAs, and DR programs will continue to serve as a valuable method for encouraging and compensating responsive resources, such as dispatchable generators, more surgically and with greater precision.

Modified DRV Calculation and Compensation

To design a more predictable and reliable version of the DRV under VDER Phase One, Staff reviewed other mechanisms for estimating distribution system value. Ultimately, the contribution made by injections into the system by VDER resources is likely to be similar, on a $ per peak kW per year basis, to the contribution provided by the portfolio of Energy Efficiency (EE) resources. Thus, Staff proposes replacing the "de-averaged" DRV with the system-wide marginal cost estimates used generically for each utility's EE benefit-cost calculations. The DRV in the Value Stack tariffs would be updated no more frequently than every two years, as opposed to the current annual update, consistent with the DSIP cycle, following the review and input process established for the biennial marginal cost study filings, discussed above. These $/kW-year values used to calculate the DRV would be the same system-wide values used for evaluating EE programs.

Staff recommends that projects be permitted to choose one of two options for compensation based on this $/kW-year value. Each option would provide a more predictable and

[3] At least for as long as consumption load continues to grow and remains significantly greater than the DG injection load on the system. In the future, as DG penetration increases, increasing injection load at certain points in the system may lead to infrastructure cost onsets rather than offsets.

reliable DRV and thereby improve the ability of the DRV to spur development of large on-site and remote projects and to encourage design of those projects to maximize system benefits.

(1) Alternative 1: Under Alternative 1, the $/kW-year would be assigned as $/kWh to the same 460 peak summer hours (2-7 PM, June-August) used for Capacity Value Option 2 under the Value Stack. This would provide advanced knowledge of the specific hours and, by spreading compensation over many more hours, substantially reduce the uncertainty resulting from a small number of hours due to factors like weather. At the same time, it would compensate a project for its performance during the overall set of hours that drives utility peak needs. The window would also simplify DRV by making the performance period the same for all territories, including the entirety of Con Edison's. One benefit of this approach is that it could induce PV systems to add solar tracking devices to their systems. To allow the $/kW-year to shift to reflect changing needs without creating an unreasonable degree of uncertainty, Staff proposes that this alternative provide stability in a manner associated with traditional tariff revisions, by limiting how much the portfolio-wide tariff value can change at each potential reset.[4] As the base value would change every two years, as described above, the $/kWh would also change to follow that shift, but would be subject to a maximum adjustment of 5% in any direction in each two-year period. Therefore, while the precise $/kWh for the 25-year Value Stack compensation period would not be known in advance, an upper and lower bound would be easily determinable. Another benefit of this approach is that it would not require tracking and compensating future VDER resources by vintage, as all eligible resources would be compensated based on the current DRV regardless of their year of interconnection.

(2) Alternative #2: Alternative 2, designed primarily for dispatchable resources, was first suggested in the New York State Energy Storage Roadmap.[5] Under this model, the $/kW-year would continue to be spread over ten peak load hours. Rather than

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4 Sometimes referred to as "gradualism" in tariff setting.

5 Case 18-E-0130, In the Matter of Energy Storage Deployment Program, New York State Energy Storage Roadmap and Department of Public Service/ New York State Energy Research and Development Authority Staff Recommendations at 33-34 (filed June 21, 2018).

> determining those hours after the fact, however, utilities would establish a call signal similar to the existing Commercial System Relief Program (CSRP) program call signal, which provides 21-hour notice before a forecasted event in which the system nears 90 percent of its rated capacity. Resources would thus be compensated for performance during the event. Staff recommends that the utilities examine whether utilizing this CSRP call signal would achieve the necessary purpose without the need to create any additional signal. Unlike the CSRP programs, however, a guaranteed number of call signals should be provided to assure that the opportunity to perform and receive the total $/kW-year value is provided to Value Stack resources. To accomplish this, the $/kW-year value would be established and fixed for 7 years at the time a project qualifies for Value Stack compensation based on the current value.[6] This will be calculated as the levelized net present value of the annual $/kW-year values in the most current marginal cost of service study for the subsequent 7 calendar years. This approach would therefore continue to require tracking and compensating resources based on vintage. At the end of the initial 7-year period, the value would be updated to the current value and would thereafter adjust every two years as a new value is established.

While projects that have already qualified arguably should be grandfathered under the rules in place at the time they qualified, Staff recommends that existing DERs be permitted to opt into the new DRV alternatives proposed above (assuming adoption by the Commission). As with the existing DRV rules, only customers not receiving an MTC are eligible for DRV compensation; therefore, in general, residential and small commercial customers that are part of a CDG project will not receive DRV compensation.

Sunsetting of LSRV

Neither of the DRV alternatives proposed above provides shorter term, above-average price signals for temporarily congested networks, as the LSRV currently does. As noted above, under Phase One it has been difficult to design a simple, stable tariff that also ties compensation

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[6] A project "qualifies" when it meets the standard for placement in a Tranche; that is, when it has a payment made for 25% of its interconnection costs or has its Standard Interconnection Contract executed if no such payment is required.

to location-specific functional and performance needs. The DSIP process, related NWAs, and the DR programs are proving to be the more effective tools to address this more complex set of problems and value. By contrast, the above alternatives, effectuated through a tariff-based approach, serve to recognize all of the projects used in utility marginal cost studies in order to produce a long run, stable value that, in essence, comprises both distribution values associated with DRV and LSRV, spread over time and across the entire service territory. For those reasons, the LSRV should be phased out, with any existing qualified projects continuing to receive an LSRV for the 10-year term; no new projects would be eligible for an LSRV. Any projects that can provide the specific functionality and performance requirements of either NWA or DR programs will continue to be eligible to participate in those opportunities to receive compensation for the grid value they can provide.

Phase One NEM for Certain On-Site Projects

Staff recognizes that the Value Stack is a new compensation model, which as it evolves, may not be well-suited for use in all cases and market segments. For instance, the Commission extended Phase One NEM to all on-site, mass market DER projects installed before January 1, 2020. Staff was also directed to work with stakeholders to develop rate design proposals that would support consideration of a new compensation mechanism for these mass market projects after January 1, 2020. The continuation of Phase One NEM under VDER is, however, limited to residential and small non-residential customers, which are defined as "non-demand metered" commercial customers thus excluding all demand-metered non-residential customers. Given the transitional nature of VDER Phase One, it is prudent to reflect on the viability of opportunities under VDER policy for smaller demand-metered non-residential customers that desire to offset their own usage with on-site DER technologies. Accordingly, Staff believes it is appropriate to extend Phase One NEM to these customers in order to encourage greater participation and investment in DER across all customer segments. Specifically, Staff proposes that Phase One NEM be available for 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 off-set; and (c) have an estimated annual output less than or equal to that customer's historic annual usage in kWh. This will apply at a minimum to all projects that qualify before January 1, 2020, for a 20-year term from each project's in-service date. Further, as these customers are, by definition, already subject to demand rates, Staff will consider whether this category of Phase One NEM should continue for new projects or should be modified as part of making its recommendations regarding a post-January 1, 2020 successor tariff for on-site mass market DG customers.

CONCLUSION

Staff proposals in this whitepaper are put forth in a collaborative spirit in order to address feedback from stakeholders and further deliberations as part of the VDER process. These proposed changes are intended to help improve the ability of the Value Stack to provide appropriate signals and compensation to developers and customers design and invest in projects that provide benefits to the electric distribution grid. Comments related to the proposals in this draft Whitepaper are requested by August 27, 2018. This draft Whitepaper will be followed by a final Whitepaper, which will receive a formal comment process prior to Commission review.