April 17, 2017

Via Electronic Filing

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Kathleen H. Burgess, Secretary
New York State Public Service Commission
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RE: Informal Comments Following Value of Distributed Energy Resources Technical Conference (Case 15-E-0751)

Dear Secretary Burgess,

Please find comments of the Alliance for Clean Energy New York, Coalition for Community Solar Access, Natural Resources Defense Council, New York Solar Energy Industries Association, Pace Energy and Climate Center, Solar Energy Industries Association and Vote Solar ("Clean Energy Parties") in response to the request for informal comments from parties after the Value of Distributed Energy Resources technical conference (15-E-0751), which took place on April 5 and 6, 2017.

Respectfully submitted,

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Introduction

On April 5 and 6, 2017, the Department of Public Service ("Department") Staff ("Staff") convened a technical conference to discuss the implementation of the Public Service Commission ("Commission") March 9, 2017 order on the value of distributed energy resources (VDER). At the technical conference, Staff expressed interest in hearing from parties through informal comments submitted by April 17. Collectively, the Alliance for Clean Energy New York, Coalition for Community Solar Access, Natural Resources Defense Council, New York Solar Energy Industries Association, Pace Energy and Climate Center, Solar Energy Industries Association and Vote Solar ("Clean Energy Parties") are pleased to submit the following comments in response to the request.

The Clean Energy Parties represent a diverse set of stakeholders that have participated throughout the process leading up to the March 9 order on VDER. We represent the overwhelming majority of New Yorkers who support solar for the economic, environmental and public health benefits it generates. We represent the thousands of New Yorkers who make a living in the solar industry, delivering those benefits to their neighbors and communities. We also represent the investors, from New York and beyond, who have invested in our solar economy and stand ready to invest further in a stable and policy-supported market. The Clean Energy Parties bring expertise from across the industry's market segments – from residential to community distributed generation (CDG) to commercial and industrial (C&I).

Comments

a. Transparency of VDER values and tranche status is critical for financing of solar.

In order for solar developers to obtain the financing needed to develop projects, it is critical that they can predict what credit rate they can expect for the energy they send to the grid. For the VDER Phase One value stack tariff, this includes estimating what the value stack will be, as well as, for CDG projects, predicting which MTC tranche they may reasonably expect to receive. This allows the developer to model anticipated project revenues, as well as evaluate opportunities for future growth in that service area or region. This understanding is needed to attract investors or financiers to support projects.

The Clean Energy Parties appreciate that the Department of Public Service ("Department") has posted several updates regarding CDG tranches to its the Distributed Generation Website,[1] and now on the Department's VDER website (www.dps.ny.gov/VDER[2]); however, the current status of the tranches should be available in one central online location that is updated regularly, at intervals of no more than 7 calendar days, but more often for utility service territories where market development warrants more regular updates. For example, the last update posted to the Distributed Generation Website was April 5th, before the technical meeting, and it showed 36 MW reserved in Orange & Rockland (ORU) territory. Since then, ORU has filed notification in the docket that it has reached 85% of total MW capacity in its service territory as of April 10, 2017, which means at least 40 MW have been reserved, but that update is not reflected on the Department's VDER website nor available anywhere online outside the DMM system.[3] More real-time updates are critical for developers to make informed investment decisions.

The Clean Energy Parties recommend that the online site should include information that allows stakeholders (including developers, or prospective financiers, among others) to understand what tranche is currently open in every service area across the state, how many megawatts (MW) of projects have already been allocated space in that tranche, and how many applications and MW are pending. In addition, past updates containing this information should also be available, in order to understand the pace of development based on the movements within and between the tranches. The Joint Utilities, the Department or NYSERDA could maintain this site. The Clean Energy Parties believe that NYSERDA may be the best fit due to its proven ability to aggregate and communicate data from multiple sources. NYSERDA is best positioned to communicate this data alongside its NY-Sun Megawatt Block program and other important information. Ultimately, as has been discussed in the DSIP proceeding as well as the Interconnection Policy Working Group (IPWG), there should be a centralized web portal that tracks progress within the interconnection queues, and this data should be clearly tied to progress within the VDER tranches. We recognize

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[1] See: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/DCF68EFCA391AD6085257687006F396B?OpenDocument, "VDER Phase One CDG Tranches," accessed April 4, April 5, and April 14, 2017.

[2] See: www.dps.ny.gov/VDER, accessed April 14, 2017.

[3] See Orange & Rockland's April 12th filing in Docket 15-E-0751: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B56DA8C01-2BAD-452D-82BE-22E103F861B4%7D, accessed April 12, 2017.

that developing more robust online queue tracking may be more involved than the simple tranche updates, and do not want the former to delay the latter, but urge the Department and NYSERDA to consider more robust queue tracking systems a priority.

In addition to presenting information regarding Tranche status, this site should also include a snapshot of the current values that comprise the VDER stack for each utility service area, load zone and LSRV area. Ideally, this site would track these values over time and show the trends of the dynamic values of the VDER stack. This information can be listed with the caveat that it is dynamic and may not represent the actual value individual projects will receive upon interconnection. However, allowing developers to see a reliable estimate of the value their projects may receive, especially an estimate provided via a centralized government agency-run website, will help developers in the early stages of project development and financing. It will also help prospective investors, financiers and customers to better understand the new VDER tariff and the credit rates they can expect to receive.

b. Transparency of individual projects' tranche allocation is needed quickly.

When a project owner puts their 25 percent interconnection deposit down to receive an allocation of space in a tranche, the project owner should also receive a timely notification of their tranche allocation within two weeks of receipt of the deposit. This notification should also include notification of the timeline for their project's interconnection process as dictated by the Standardized Interconnection Requirements (SIR) or queue management requirements.

c. Transparency and confirmation of individual projects' VDER value stack, including E value, is needed upon payment of 25% interconnection deposit.

In addition to timely confirmation of tranche capacity and the associated MTC level upon payment of 25% interconnection deposit, project owners should also be able to confirm any other fixed elements of the value stack, namely the E value, at that time. While the Commission's March 9 VDER order adopted Staff's proposal as outlined in the October 27, 2016 Staff Report to set the E value upon project interconnection, the Clean Energy Parties urge the Commission to correct this timing to align with the reservation of tranche capacity/MTC level, which occurs upon payment of 25% interconnection deposit. Setting the E value as well as MTC level upon payment of 25% deposit, and clearly communicating those values to the developer at that time, will better enable developers to secure financing to move through the construction of their project and to begin marketing to and acquiring customers. This notification should be received within two weeks of receipt of the deposit and should guarantee the receipt of those values for generation upon interconnection.

d. Several remaining details related to the VDER capacity component implementation should be addressed.

The Clean Energy Parties agree with the Commission's decision that a more interim step than the capacity tag method was needed for non-dispatchable projects under the Phase One VDER Tariff, and appreciate the flexibility provided to select the Alternative 1 or Alternative 2 capacity method for those projects as we further explore how to look at the capacity value in Phase Two. In reviewing the order and after the April 5th technical conference, however, several important unresolved questions remain about the capacity value for the Phase One Tariff alternatives for non-dispatchable projects, including:

1. As Staff suggested at the technical conference, the utilities should be required to report publicly on a monthly basis the capacity charge portion of retail supply rate in $/kWh for the relevant service classification(s), as that is currently not available (except in Con Edison territory). In addition, each utility's general standard calculation methodology for how they arrive at that capacity charge portion of the retail supply rates from their capacity purchases and standard load profiles should also be shared and updated if the methodology changes so that the values can be understood, and the calculations can be duplicated and used in modeling for this component of the Phase One Tariff.
2. The customer load profile that will be used for the capacity calculations for Alternative 1 and Alternative 2 needs to be confirmed, and the Clean Energy Parties agree with the Staff and the Commission that the load profile used should be the one most coincident with solar generation. However, the SC1 load profiles have been the only ones used by the Department and the Clean Energy Parties for Phase One Tariff modeling to date and given the large number of load profiles, if the utilities recommend a different load profile be used for the capacity calculations, the evidence supporting their recommendation

should be shared publicly including the solar generation profile used. If this is not provided, the SC1 load profile should be used for the Phase One Tariff instead.

3. For the Alternative 2 capacity method for dispatchable technologies, the 460 hours that will be used should be clarified and confirmed. In the order, the hours are listed as "the 460 peak summer hours: hours 14:00 through 18:00 each day in June, July and August".[4] The Clean Energy Parties read that as from 2pm to 6pm for those months, which would be 4 hours for 92 days = 368 hours. As we know the goal is to have 460 hours, we assume that the intent is to have 5 hours/day for the 92 days. We request clarification on which 5 hours we should plan on: the 2pm-7pm or 1pm-6pm ET timeframes.
4. For the Alternative 2 capacity method, the Clean Energy Parties agree with the discussion in the technical conference that the value available to projects that select this method is based on the annual capacity cost for a customer of the selected load profile per kW. The order uses the term "$/kW/year", which from the Staff Report, workbooks, and previous discussions we understand to be accomplished by calculating the average $/kW over the year for the given load profile and then applying that to the total number of kWs of actual production from the solar facility in the designated 460 hours each year. In this, however, there are two key points to clarify.
    a. First, when calculating the average $/kW over the year for the given load profile before it's applied to any particular project's performance, it should be clear how exactly the average $/kW over the year will be arrived at. For example, after the capacity portion of the supply rates for each month are used to calculate the total monthly capacity cost to the customer profile, will this be divided by the average capacity in kWs for the relevant load profile? Or, will it be divided by some other value, such as the average of the daily maximum demands or the absolute maximum demand from any hour of the month? To date, this methodology has not yet been made public. We expect these calculations will overlap with the general calculations the utilities do to create the capacity charge portion of the retail supply rates from capacity purchases and standard load profiles initially, and

[4] See VDER March 9 order, page 100.

we've requested that information be shared above in #1, but the Alternative 2 capacity method makes the transparency of this calculation even more important.

b. Second, the Staff recommended for the Alternative 2 capacity method that "the prior 12 months of Service Class 1 monthly capacity statements would be used to determine the $/kW per year," [5] while from their presentation at the technical conference, the utilities seem to be requesting prospective pricing based on the 6 month summer auction price and the forward curves for the following winter.[6] The use of published retrospective pricing is preferable for clarity, transparency, and accuracy as it will be published by the utilities and will not require a reliance on market assumptions about future weather and related electrical demands. This is critical in our experience to developers being able to use this Alternative 2 method. Thus for these reasons, we request that the prior 12 months of capacity statements be used to calculate the $/kW value.

Developers are attempting to model project economics and make investment decisions now, so it is critical to clarify the above issues related to capacity value as soon as possible so that those decisions are as informed as possible to support efficient transactions and successful project development.

e. The Demand Reduction Value (DRV) and Locational System Relief Value (LSRV) should fully compensate distributed energy resource customers.

The VDER order states that DRV and LSRV values will be derived by de-averaging the Marginal Cost of Service (MCOS) studies filed by each utility in their most recent rate case filing. The MCOS studies are primarily comprised of two categories of costs. First, there are typical operations and maintenance costs, taxes, and customer-related costs associated with keeping the entire distribution system running reliably. Second, there are the costs associated with new capital projects within the utility service territory. The latter category of costs is more locationally distinct, as the costs are directly attributable to specific projects.

[5] Ibid.
[6] See the JU Presentation from the April 5th technical conference, slide 49.

The utilities presented a number of different approaches to de-averaging MCOS studies to derive a DRV and LSRV value. The Clean Energy Parties appreciate these presentations as a useful first step to developing a methodology for determining these important components of the value stack, and look forward to reviewing the utilities' forthcoming filings on this issue. In our view, the Commission should keep the following principles in mind when evaluating whether these filings comply with the intent of the VDER order.

- The purpose of the DRV and LSRV, as set forth in the Commission's order, is to accurately compensate DER owners for the value their assets provide to the grid—not to deliver net savings to bill payers as suggested by the JUs at the technical conference. Therefore, DRV and LSRV values should be fully representative of the distribution costs that DERs can avoid. Other initiatives (e.g., the Non-Wires Alternatives procurements) are a more appropriate forum for reducing bill payer costs.

- Developers must be provided with more certainty regarding how the LSRV, and in particular the DRV, for their projects may be modified over time.

- The DRV and LSRV should be built up from the full MCOS study, rather than a subset of capital projects. Any decision to exclude particular capital projects from calculation of the DRV or LSRV should be explicitly called out and justified in the utilities' DRV and LSRV filings.

- The utilities should not disqualify capital projects from the DRV/LSRV based on "suitability criteria" that were developed for the Non-Wires Alternatives process.

- DRV and LSRV should not be double-derated based on the DER generation profile.

- The DRV and LSRV methodology should balance the need for administrative simplicity with the VDER order's direction to the utilities to provide more granular values for avoided distribution costs.

The Purpose of the DRV and LSRV:

We believe there may be a misunderstanding among certain stakeholders of the purpose of the DRV and LSRV. As with the other components of the value stack, the DRV and LSRV values are intended to reflect the fact that installing DERs on the grid can avoid the need for numerous different types of distribution-level costs. The DRV and LSRV components of the VDER value are intended to accurately quantify the value of these avoided costs and to provide the appropriate compensation to DER owners. They are not intended to provide net savings to non-DER owning bill payers at the expense of DER-owning bill payers. We therefore do not agree with the following statement in Central Hudson's section of the JU presentation: "In developing location specific values, the avoided costs would need to be devalued since paying the full avoided costs to DER providers would result in no net savings for customers."[7]

In making this statement, Central Hudson appears to be conflating the goals of the VDER order with the goals of a non-wires alternatives or similar process. The central goal of the VDER process, as articulated by the Commission, is to properly compensate DERs for the benefits provided to the distribution system. The only available benchmark for identifying those benefits is the avoided cost of the traditional distribution solution. This task should not be conflated with the focus of the non-wires alternatives solicitations—whose goals are not to set the appropriate compensation level for a particular DER solution, but rather to identify the least expensive alternative to the traditional capital expense.

Finally, the Clean Energy Parties would like to mention that while these comments address the calculation of the DRV and LSRV, we do not endorse the use of these methods for compensating distributed energy resources for the delivery value. During the process leading to a Phase 2 VDER tariff, we do not support the DRV and LSRV as the starting point, let along the end point, for discussion of the delivery value.

The rules for DRV and LSRV calculation must provide greater clarity regarding future value:

The March 9 VDER order sets forth a framework by which "the DRV and LSRV shall be determined every three years."[8] It provides that "[a]ny project that receives a LSRV shall receive that compensation for a period of ten years," whereas "DRVs shall not be fixed, but instead change as they are updated by the utility on the three-year basis."[9]

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[7] See JU Presentation from the April 5th technical conference, slide 9.
[8] VDER March 9 order, page 118.
[9] *Id.*

In order for the DRV and LSRV components of the value stack to meaningfully contribute to the financeability of future projects, project developers and financiers must be able to predict how these value stack components will vary over time. In the wholesale market context, for example, organized market rates for energy and capacity vary over time, but rules surrounding how those rates will be calculated through the operation of the markets help project developers to predict what prices will be over time. Because the terms of the VDER order dictate that the DRV for a project is subject to modification as the applicable utility's MCOS study is updated, and that the LSRV for a project is subject to modification after its tenth year in operation, developers and financiers must assess how those values will change over time. Without basic rules surrounding how MCOS studies may be modified, however, that task becomes impossible.

Given the integral nature of clear rules to predicting DRV and LSRV value, our working assumption had been that in crafting an implementation order, the Commission could provide basic standards for the development of MCOS studies, and the process of "deaveraging" value between DRV and LSRV. At the technical conference, however, it became clear that each utility's current methodology is significantly different such that any uniform process for DRV or LSRV development would be difficult if not impossible to achieve. The utilities have proposed highly individualized processes based in part on historical differences in their MCOS calculation methods.

The result of this combination of varying DRV and LSRVs and an undefined process for future MCOS development, however, is a completely unpredictable value stream for a project's distribution value component over the life of the project. A project developer cannot count on receiving the DRV, for example, because in three years the utility might heavily 'deaverage' such that nearly all system value is transferred into LSRVs at different locations from which the project is sited. With no boundaries in place surrounding the de-averaging process, it is impossible to predict how much erosion in DRV value will take place over time. Further, a project developer has little ability to predict where future LSRVs may be located due to the lack of information utilities have released surrounding potential future constraints, and the absence of any rules regarding when a new LSRV must be formed. In addition, with the LSRV fixed for only a ten year period, projects threaten to cannibalize their own value to the system. While a project may have contributed to the elimination of a system constraint, after year 10 if the constraint contributing to LSRV creation is alleviated the system will receive no value despite having been integral to the elimination of that constraint. This stands in stark contrast to a traditional T&D investment, for which a utility would continue to earn a return on capital, even if the construction of new DERs or other factors cause the infrastructure to no longer be needed. Given the lack of clarity surrounding when an LSRV zone will be retained, project developers have no way of predicting whether an LSRV will remain in place after year 10.

We recognize that, given the wide variation between utilities in MCOS methodology, as presented at the technical conference, there is value to allowing flexibility and variation in the manner in which each utility calculates DRV and LSRV. Nevertheless, so as to most efficiently leverage DRV and LSRV value, the Commission should do *something* to provide developers and financiers with greater certainty. If it does not do so, developers and financiers will be forced to discount the DRV and LSRV components of the value stack, and far less solar will be developed than would have been possible using the same total credit value with a clearer valuation methodology.

In assessing this conundrum, we strongly recommend that staff and the Commission reconsider the concept of vintaging so as to provide projects built based on current MCOS value with some certainty. Other, less preferable ideas that may nevertheless contribute to greater certainty include:

- A guaranteed value floor below which DRV and/or LSRV for certain project vintages may not fall;
- Facilitation of a ‘risk pool’ for projects such that participating projects that unexpectedly receive greater value through the creation of an LSRV than they anticipated would share these credits with projects whose DRV value was eroded through that LSRV creation; and
- Basic boundaries for MCOS development and future DRV/LSRV apportionment that provide at least some clarity surrounding future value while still facilitating necessary variation among utilities.

The DRV and LSRV should be built up from the full MCOS study:

In the March 9 VDER order, the Commission directed each utility to file its most recent MCOS studies, along with the associated work papers. In lieu of a formal MCOS study and work paper, Central Hudson filed its recent Location Specific Forecasting and Marginal T&D Cost Study, which was originally filed with the company's Distributed System Implementation Plan. While Central Hudson's leadership in developing a marginal T&D study based on probabilistic planning methods and econometric models should be commended, it does present some challenges in developing a common DRV and LSRV methodology between service territories.

Most notably, the Central Hudson marginal cost study may exclude various types of capital projects that were included in the other JU MCOS work papers. Specifically, Central Hudson's filing appears to pre-emptively exclude projects that were included in its capital plan based on "suitability" criteria that were developed for the Non-Wires Alternatives process. As discussed below, several of these suitability criteria are not appropriate for the DRV and LSRV valuation process, and they should not be imported wholesale into the DRV and LSRV methodology. In our view, the DRV and LSRV calculation methodology must, at a minimum, start with an examination of the full list of capital projects in utilities MCOS studies to comply with the intent of the VDER order.

The utilities should not disqualify capital projects from the DRV/LSRV based on "suitability criteria" that were developed for the Non-Wires Alternatives process:

In November 2016, the Joint Utilities filed "Suitability Criteria" for determining which utility capital projects would be eligible for Non-Wires Alternatives (NWA) solicitations. The rationale for these criteria was that there are certain types of utility projects that address system issues that DERs located at a particular location cannot help improve. As such, those capital projects would not be suitable for a DER alternative. One example often used are capital projects to replace old and aging infrastructure. In the context of NWAs, the JU Suitability Criteria explains that DERs are "not likely to improve the condition of existing T&D assets that must remain in service" and therefore, DERs are not a suitable alternative to this kind of traditional capital project.

However, in the context of VDER, the use of this "suitability criteria" would result in a systematic undervaluation of DERs' value to the grid. While the suitability criteria may be appropriate in the context of the NWAs, that usefulness does not transfer to the VDER context. NWA suitability criteria are focused on identifying projects where a solicitation for non-wires alternatives is particularly appropriate because the unique characteristics of the project type make it easier to avoid the cost of upgrading or repairing a single asset at a single location. The NWA suitability criteria were developed in recognition of the fact that it is difficult for utilities to integrate NWAs into their planning process for all project types at once, so they should begin with those for which NWAs are most promising.[10] Further, it recognizes the limitations of the solicitation model, where a specific defined need must be articulated in advance for the particular traditional infrastructure project at issue to be deferred or avoided. While stakeholder recognized the value of these criteria to "direct developers to the highest potential opportunities,"[11] the aspiration is that over time the utilities will integrate NWAs into planning for *all* project types, and recognize the value of NWAs beyond their ability to defer or replace specific identified traditional infrastructure solutions.

Suitability criteria should not be used to automatically exclude capital projects that do not pass these narrow "suitability" tests from the group of projects that can be delayed or avoided by the installation of DERs on the larger system. Doing so would fail to adequately reflect the system-level value that DERs provide.

For instance, taking the hypothetical aging infrastructure project as an example, DER penetration in aggregate would reduce the demand on distribution assets across the system, reducing the physical and thermal usage of these aging assets and extending their life. Thus, although the presence of any particular identifiable DER on the grid does not avoid the need to replace aging infrastructure, deployment of many DERs can help to extend the lifetime of this infrastructure. Further, higher DER penetration could reduce the size or technical capabilities needed for replacement infrastructure once the aging infrastructure at issue has reached the end of its useful life. These are services that provide a tangible benefit to bill payers, and for which DERs should receive compensation.

[10] The utilities' own Supplemental Distributed System Implementation Plan, for example, states that their announced NWA suitability framework was designed "to identify those projects that are *most* suitable for NWA," so as to "provide a transparent means of prioritizing utility projects according to their suitability for a competitive NWA solicitation." Case 16-M-0411, *Supplemental Distributed System Implementation Plan* at 41 (Nov. 1, 2016) (emphasis added).
[11] *Id.*

In moving from net metering to a more granular valuation process for DER, the Commission has sought to unbundle the costs and benefits of DERs, and to rebuild, from the ground up, a compensation mechanism using a value stack that appropriately compensates DERs for each of the values provided. While many of the direct benefits (e.g., energy and capacity) have been accurately accounted for, the use of Non-Wires Alternative suitability criteria to derive DRV and LSRV would risk losing track of some of the more diffuse benefits, such as equipment life extension.

Rather than using the NWA "suitability criteria" or other filters to exclude certain capital projects—which would artificially lower the DRV and LSRV compensation provided to DERs—the Commission should build up the DRV and LSRV values from the full universe of capital projects within each utility's MCOS work papers. Capital projects—such as aging infrastructure projects—that are necessitated by diffuse system-wide factors or that benefit most system users would be used to calculate the DRV, whereas targeted capital projects that are necessitated by activity or events on a particular circuit or substation would be suitable for inclusion in the LSRV. Only capital projects that would not be affected in any way by the presence of DERs on the system would be suitable for exclusion from the DRV and LSRV calculation.

The DRV and LSRV should not be double-derated based on the DER generation profile:

The Joint Utilities propose de-rating the DRV and LSRV value by reference to a coincidence factor based on the expected availability of DERs. This additional "availability" derating is neither necessary nor appropriate. Under the VDER order, the total DRV and LSRV for which a DER is eligible is already discounted based on that resource's coincidence with the ten most heavily loaded hours of the previous year. In other words, the VDER order already provides that variable DERs be de-rated based on their coincidence with peak load. The JUs' proposal to further de-rate solar and other DERs based on coincidence with peak load is therefore unnecessary, and would significantly undervalue the benefits provided by DERs.

The DRV and LSRV methodology should balance the need for administrative simplicity with the need to identify more granular values:

We urge the Commission and DPS staff to think critically about how to balance the need for administrative simplicity in implementing the DRV and LSRV with the need to identify more granular values. Given that we are currently in the first phase of a multi-phase VDER process and that many of the concepts discussed in the VDER order are new and complex, it is reasonable to expect that some approximation will be necessary to ensure that the DRV and LSRV values can be identified appropriately and on schedule. However, it is important that any such approximation or averaging not result in the discounting of the value that DERs provide to the grid. The Clean Energy Parties looks forward to reviewing the utilities' forthcoming filings and working with all stakeholders to ensure that DERs receive the appropriate compensation for the many benefits they provide to the grid and to society.

f. Comments on the calculation and allocation of CDG credits.

The MTC and DRV allocation procedures as presented on Slide 58 of the Joint Utilities' presentation at the April 5th technical conference raised some confusion, which we seek to clarify here.

We understand that Department staff has interpreted the order as follows: A CDG project generates a certain number of kWh per month. All kWh are valued at the value stack rate, and those kWh associated with residential and small commercial subscriptions receive an MTC in addition to the value stack (the exact MTC is dependent on customer class), and those kWh associated with large commercial (demand-metered) subscriptions receive the DRV in addition to the value stack.[12,13]

We believe staff's interpretation is the appropriate way to calculate credits to each customer class (*credit = kWh associated with customer class * $ rate associated with that customer class*). It appears the JU is proposing to add another step, in which all components of the value stack, including the MTC and DRV, are summed together for the entire project, and the credits to each customer class are then calculated as *total dollar credits for project * % of kWh associated with customer class*. This additional step unnecessarily complicates the calculation of

[12] We emphasize that in future iterations of the Value of DER tariff, it may be more appropriate to value kWh generation irrespective of subscriber composition, but accept that this is the framework under the Phase One Value of DER paradigm.
[13] The value stack will include LSRV if the project falls within an LSRV zone and any MW cap associated with the LSRV. In the JU presentation, the DRV and LSRV value are calculated on a $/kW rather than $/kWh basis, but the resulting dollar value can easily be divided among the kWh associated with C&I customers (for DRV) or all kWh (for LSRV).

bill credits. Under this approach, each individual subscriber effectively receives both a partial MTC value and a partial DRV value. As a result, an existing subscriber's bill credit rate would change if the project's overall subscriber composition changed, which would be extremely challenging for CDG hosts to manage and extremely confusing to customers. Intuitively, if the size and configuration of the project remains the same and all other subscribers remain the same, changing one subscriber in a project (for example, replacing a residential customer with a small business customer) should not cause the bill credits for other subscribers to change.

On April 14, Staff submitted a filing entitled, *Calculating Bill Credits for 2 Simple CDG Examples* that demonstrates the two above interpretations. We support Alternative 1 as outlined in that filing.

We note that in compliance tariffs and other implementation filings it will be important to continue to be clear that the monetary credits generated by a CDG project are tied to energy generation, that the credits applied to customer bills derive from that energy generation even though they are ultimately applied as monetary credits, and that they cannot be converted into cash but rather are used only to adjust retail rates (i.e. that they modify only the retail sales made to that customer).

We encourage the utilities to coordinate on this component of their Implementation Proposals due May 1 such that the language in each utility's proposal with respect to calculation and allocation of CDG credits accurately describes the calculation and allocation of credits, and is identical, to facilitate stakeholder review and input of this complex aspect of tariff implementation, in which specific wording and details matter.

g. Comments on tranche size based on CDG subscriber mix.

The portion of projects that receive an MTC and the customer classes of those subscribers has a direct impact on the expected residential net revenue impact calculation on which the tranches are based. If less than 100 percent of subscribers are residential, which we expect will be the case, than the tranches as currently calculated are smaller (i.e. fewer MW) than what would otherwise be allowed if the calculation were based on the actual subscriber mix. Either in implementation or during the six-month review of the program and tranche progress, the

Commission should consider the real subscriber mix of projects moving forward and quickly update the tranche sizes to reflect the actual expected residential net revenue impact.

h. Comments on bill credit application.

In its March 9 order, the Commission directed utilities to file Implementation Proposals by May 1 that include "utility processes for managing billing and tracking bill credits."[14] In addition, the Commission directed Staff to "confer with utilities and market participants to [sic] and report to the Commission regarding what actions can be taken to provide efficient two-way electronic communication between CDG providers and utilities regarding subscriber lists and bill credit calculation and application to customer bills to enhance customer experience and reduce customer management costs."[15]

We note that timely, accurate, transparent, and efficient bill credit application is fundamental to the successful implementation of a community solar program. Customers sign up to participate in community solar projects expecting timely and accurate credits on their electric bill, and it is the responsibility of community solar providers, utilities, and regulators, collectively, to ensure customers have the positive experience they expect and deserve.[16]

In October 2015, following the Commission's July 2015 order instituting the CDG program, each utility filed a CDG operating plan listing procedures for communicating with community solar providers regarding subscribers lists and bill credit allocation. Most of these procedures rely primarily on manual processes. Because the development of CDG projects stalled across the state awaiting the Value of DER order, only a few projects have come online and begun utilizing the processes laid out in the 2015 operating plans.

With the Phase One Value of DER order now in place, and the expectation that many more MW of CDG projects will come online over the next year, serving many thousands of

[14] See VDER March 9 order, page 136.
[15] See VDER March 9 order, page 144.
[16] The emphasis in these comments is on efficient systems for CDG bill crediting; however, such systems can perform RNM bill crediting as well. RNM does not present quite as much of a bill crediting challenge as CDG because there are fewer satellite accounts, but solar project owners and customers have reported problems with RNM billing and some utilities have recognized that automation of RNM crediting would be helpful.

customers, it becomes necessary and prudent to automate many of these processes to reduce error, lower administrative costs, and better serve customers, developers, and utilities. If customers are to understand and engage with the energy products they receive, which is a key goal of REV, there must be timely, transparent communication of all important data (including production and rate components), between utilities, developers, and customers.

We recommend that the Commission require utilities to implement systems with at least the following basic data and functionality:[17]

- Project registration
  - Account creation and designation of project information (e.g. capacity, load zone, parcel designation, required documentation)
  - Election of program choices (e.g. capacity value calculation alternative, election to retain E value vs. retain RECs, among others)
- Subscriber information and validation
  - Ability for CDG host to enter subscriber information, consent to disclose form, and obtain automated subscriber validation and historical production
  - Ability for CDG host to make prospective updates to subscriber allocation percentages
- Rate information
  - Applicable components of the value stack (E, MTC, capacity, load zone hub for LBMP, DRV, LSRV) based on project type, tranche allocation
  - Energy values: upload/import rate information from utilities (e.g. retail NEM for Tranche 0, DA LBMP values from MHP tariffs for value stack tariff)
  - Other tariff components:
    - E Value: assigned by project upon payment of 25% of interconnection costs[18]
    - ICAP: upload from utility on annual basis

[17] This is not a fully comprehensive list; utilities should work with experience third-party software providers and community solar developers to develop full IT requirements

        - MTC: upload from utility at project commencement, for all customer classes
        - DRV and LSRV: if applicable, upload from utility as they are established

- Production information by project
    - Hourly production for all projects; ideally integrated through utility central hub for generator production data, allowing for tracking of official, utility-certified production on a live basis
    - Store historical hourly production information by project
- Calculation of credits
    - Using data on project, subscribers, and value stack elements identified above, calculate hourly credit assigned to each customer account
    - Generate bill credit file, by subscriber, with a copy of the report to the project owner
    - Can automatically flag any exceptions
- Allocation of credits assigned to host account
    - Generation of credit file to post to host account, illustrating how credits were calculated
    - Track credit banking and rollover
    - Ensure compliance with program rules including two year grace period for expiration of credits, customer limits, etc.
- Reporting
    - Automated generation of reports for all stakeholders (DPS, NYSERDA, utilities, project owners)
    - Controls for information security based upon participant role
- Audit functions
    - Allow for full auditing capabilities of all calculations, based upon federal and state requirements

<u>The Commission and utilities should make adoption of online, efficient bill crediting systems a near-term priority.</u> These systems can easily take six months or more to implement, which means work must begin now in order to accommodate the projects expected to come online in the next year. We have seen in other states, Massachusetts in particular, the negative

customer experience that can result from errors and poor communication associated with more manual processes. Furthermore, given that New York is focused on reducing the soft costs of solar, it is important to recognize that inefficient crediting processes in other states have directly impacted the overhead costs for community solar providers, as customer service staff spend a significant amount of time trying to interpret opaque utility billing statements, attempting to answer customer questions about late or inaccurate credits, and trying to reverse engineer the utility rates and credit allocations to ensure all are done correctly.

New York can and should avoid those problems and help lower soft costs of CDG development by pursuing IT solutions now. Utilities should be required to consider third-party software and service solutions that can provide such functionality, as third-party solutions may be implemented more quickly and at lower cost.

With respect to how bill credits are labeled on customer bills, we recommend at minimum a standard label of "Community DG Credits," and ideally the ability to indicate somewhere on the bill which CDG project is generating the credits, which could be a brief name field provided by the community solar provider, e.g. "Catskill Community Solar Array."

i. Explore offering consolidated billing as an option for CDG providers.

The March 9 VDER order directed Staff to confer with utilities and market participants to "evaluate and report to the Commission whether utilities should be required to offer consolidated billing for CDG subscriptions, to improve the customer experience and reduce collections costs."[19] Consolidated billing refers to a situation in which the utility posts not only the CDG credit on their bill, but also the charge for the CDG subscription, such that the customer pays only one bill, and the utility remits the portion of the payment that is for the CDG subscription to the CDG provider, minus any fee the utility may charge for the billing service. Figure 1 below depicts a simplified sample subscriber utility bill with consolidated billing for a CDG subscription, as discussed on April 6 at the VDER technical conference.

[19] See VDER March 9 order, page 144.

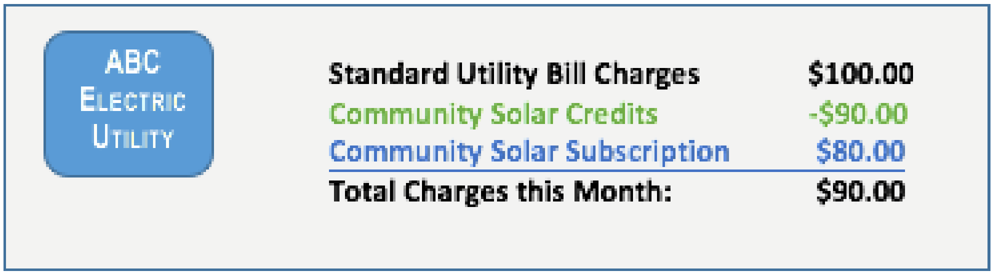

Figure 1: Simplified Sample Utility Bill: On-bill debiting for community solar lowers customers' utility bills; in this example, the customer is saving $10/month as a result of participating in community solar

As more community solar programs emerge and begin to reach scale in leading states, it is becoming clear that consolidated billing could represent an opportunity to help community solar reach scale and better serve consumers. In New York, we support exploring consolidated billing in the form of an on-bill repayment type of structure as <u>an option</u> for community solar providers.[20] Some community solar providers may choose to continue billing their own customers directly, and at this early stage of the market it is appropriate to enable many different business models and allow market forces and consumer preferences to determine optimal approaches over time.

Consolidated billing has the potential to improve the customer experience, create new revenue opportunities for utilities, and lower costs for customers, utilities, community solar providers, and all bill payers. It could also help facilitate low-income customer participation in community solar programs.

One question raised at the April 6 technical conference with respect to consolidated billing was how it could accommodate the different product offerings of different community solar providers. With respect to data exchange, the community solar provider could be required to provide the appropriate amount to charge each month to the utility. With respect to consumer protection and consent, all community solar providers opting for consolidated billing could be required to obtain customer signature on a plain language form allowing the utility to place said charges on their utility bill.

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[20] There are different ways to structure consolidated billing, from on-bill repayment to purchase of receivables (POR). The Clean Energy Parties propose exploring an on-bill repayment type of structure at this time and recognize that other approaches may be more appropriate as the CDG market matures.

We look forward to further iteration with utilities, DPS staff, and other stakeholders on how best to implement consolidated billing to support CDG development and offer customer options.

j. Increase the project size maximum from 2 MW to 5 MW.

The Clean Energy Parties concur with the order's statement, "Allowing projects larger than 2 MW to participate in the VDER program could significantly lower per-MW costs."[21] The Clean Energy Parties propose that the project size be increased from 2 MW to 5 MW. While the Clean Energy Parties note that even larger project sizes should be considered in the future, 5 MW is an appropriate increase at this time because it lines up with New York's *Standardized Interconnection Requirements and Application Process for New Distributed Generators 5 MW or Less Connected in Parallel with Utility Distribution Systems* and therefore does not require additional policy changes. It balances the need to act quickly and efficiently to maximize results with minimal complexity.

Larger project sizes result in lower per MW-costs and other benefits:

Larger projects can better optimize limited available land from the land acquisition process as well as from a siting configuration perspective. Permitting is a significant upfront cost and these costs are also optimized with larger projects that don't require the subdivision of parcels. This also allows parcels of land that are perfect for hosting solar projects, such as landfills or other brownfields, to fit a larger project. These sites are often larger than what is required for a 1 or 2 MW project and maximizing the use of this space minimizes the number of different parcels of land that need to host projects. This is also true for other sites, reducing the amount of land and number of places that projects need to be built.

There are critical efficiencies and cost reductions to be gained in the interconnection process for both the developers and utilities, as one 5 MW project only has to conduct one interconnection study and only requires the equipment for one point of interconnection. This reduces the staff capacity and investment that both project developers and utilities need to put into this work. There is also an advantage to allowing larger projects in paying for distribution system upgrades. These projects will be better able to absorb larger costs levied by the utilities through

[21] See VDER March 9 order, page 143.

the interconnection process, and may therefore pay for system upgrades that will allow many smaller projects to interconnect at a reduced cost afterwards.

Finally, larger projects benefit from simple economies of scale. These projects will be able to disburse some construction and operation costs over a larger system, buy equipment and ship it at a lower cost and market to and acquire customers in a larger batch.

Enable projects up to 5 MW to participate in the VDER Phase One tariff as well as the Phase Two tariff:

The Clean Energy Parties propose that the Commission allow projects up to 5 MW to participate in the VDER Phase One tariff as soon as possible rather than waiting for Phase Two. This could help stimulate the CDG and C&I markets statewide. As Staff compiled data regarding the VDER Phase One CDG Tranches clearly demonstrate, CDG development in multiple service territories is lagging, or otherwise has yet to begin, at the current Phase One NEM crediting rates.

In those service territories in particular, increasing the project size could be helpful immediately and result in development activity under Phase One in places that otherwise appear to be closed for business. In all of the territories, the cost reduction associated with increasing system size will allow later tranches to drive continued growth in the state.

Finally, in addition to these benefits, the Clean Energy Parties see no downside to making this change. The potential rate impacts of the VDER Phase One tariff have already been rigorously bounded and contained, and this change would not alter that bounding or increase exposure to ratepayers. In addition, the Megawatt Block program sets out differentiated incentives for different projects sizes and can ensure a continued diversity of projects. This change would simply continue to enable the cost of solar development to be reduced and thus occur more successfully across the state.

Conclusion

The CDG Stakeholders are grateful to the Commission and Staff for the opportunity to provide comments in response to Staff's solicitation. We remain committed to finding a path towards a fair compensation mechanism for solar customers and sustained and sustainable solar growth in New York, and appreciate the Commission's ongoing efforts on this front.