Value of Distributed Energy Resources (VDER) – Case 15-E-0751

Frequently Asked Questions

Updated 6/23/2017

New Questions

Q: *How is monetary crediting applied when a CDG offtaker has an ESCO or third-party supplier?*
A: If the offtaker has consolidated billing, they will receive a monetary credit on their bill that is applied to the entire bill, including both the delivery (utility) and the commodity (ESCO) charges. If the offtaker has separate billing for the utility and the ESCO, the value stack monetary credit is applied to the utility bill only.

Q: *When calculating a system's DRV or LSRV payments, is the DG system's AC capacity used?*
A: No. Since it is unlikely a DG system will operate at full capacity during each of a year's 10 peak grid demand hours, the system's actual AC output averaged over those 10 hours is used. For year 1, the project's modeled AC performance is used, as calculated by a capacity factor specified by the utility.

Q: *Can a project receive both the Value Stack and the NY-Sun PV incentive?*
A: Yes. Participation in the NY-Sun program is unrelated to a project's utility compensation (whether NEM or the Value Stack).

Q: *Are small commercial systems considered mass market?*
A: According to the VDER Order, mass market customers are those that do not have demand billing or mandatory hourly pricing.

Q: *Does the 3/9/2017 VDER Phase One Order change the technologies and maximum system sizes that are eligible for grid interconnection?*
A: No.

Q: *Will interconnection applications submitted to the utilities for prior to March 9, 2017 still be processed?*
A: Yes.

Q: *Can a project receive both the LSRV and the NY-Sun locational adder?*
A: Yes, under current program rules.

Q: *Will compensation under the value stack always be lower than under NEM?*
A: This will vary project-by-project. In many cases, compensation will be lower under the value stack than under NEM. In certain circumstances, compensation may be higher under the value stack, especially when the LSRV is considered.

Phase One NEM

Q: *If a project qualifies for Phase One NEM, how will generation output from that project be valued after the compensation term has expired?*

A: The compensation term length for Phase One NEM is 20 years from the date of interconnection. After the 20 years has expired, the project's generation would be eligible for compensation under the then-applicable compensation mechanism. The VDER proceeding is an ongoing process through which subsequent phases, and associated compensation mechanisms, are anticipated.

Q: *What is the deadline for projects to qualify for Phase One NEM?*

A: The deadline for non-mass market projects to qualify for Phase One NEM is 90 business days from the date of the VDER Order, which is July 17, 2017. Eligibility for Phase One NEM is limited to those projects that have made payment of at least 25% of interconnection upgrade costs by that date or have executed an interconnection agreement by that date if there are no interconnection costs associated with the project. Eligibility for Phase One NEM for CDG projects is further subject to available capacity in Phase One Tranche Zero, discussed further below. Mass market projects are eligible to receive Phase One NEM until 1/1/2020.

Q: *For remote net-metered projects that qualify for monetary crediting through grandfathering provisions previously adopted by the Commission, but are not yet constructed, does the new VDER Order impose any new requirements on those projects to retain grandfathered status? Does the VDER Order impact the compensation term length of 25 years?*

A: The VDER Order does not impose any new requirements to retain grandfathered status or impact the compensation term length.

Q: *For in-service projects compensated under NEM or Phase One NEM, would a project's compensation status be impacted if a project were to increase in size (i.e., add additional capacity)?*

A: Staff is reviewing this issue and anticipates developing criteria within 30 days to address this question.

Q: *Does the VDER Order alter the core NEM principle of being able to carry forward credits from one billing cycle to the next?*

A: Projects that are grandfathered under NEM will continue to be permitted to carry forward excess credits consistent with the current NEM rules. Projects that are interconnected under either Phase One NEM or the Phase One Value Stack will be permitted to carry forward credits from one billing cycle to the next, irrespective of whether the credits are volumetric, as in the case of Phase One NEM, or monetary, as in the case of the Value Stack. VDER Phase One does not permit the payout of credits at any time including at the end of a project's annual period. Annual carryover of credits under VDER Phase One is permitted until the end of the project's Phase One compensation term of 20 years for Phase One NEM and 25 years for Phase One Value Stack.

Q: *How and when can a customer arrange to be separately metered and opt-in to the Phase One Value Stack for exported generation on a net-hourly basis?*

A: Staff is working with the utilities to develop a standardized process for making such requests and anticipates resolution in conjunction with implementation of the Phase One Value Stack tariffs. The installation of separate metering for existing projects will be subject to utility schedules and applicable costs.

Qualifying for Phase One NEM

Q: *Does the VDER Order take into account the time it takes for interconnection applications to be reviewed by the utility and how the interconnection process is impacted by the 90 business day eligibility period for Phase One NEM?*

A: The design of the VDER Order takes into account the interconnection process as amended by the January 2017 interconnection queue management decision. The 90 business day deadline for participation in Phase One NEM appropriately provides projects that were in active development at the time of the VDER Order the opportunity to receive Phase One NEM.

Q: *Do only projects interconnecting between July 17, 2017 (90 business days from the date of the VDER Order) and the date of the VDER implementation Order qualify for Phase One NEM?*

A: To qualify for Phase One NEM, a project must have paid 25% of interconnection upgrade costs by July 17, 2017 or have executed an interconnection agreement if there are not interconnection upgrade costs associated with the project. CDG projects are further subject to available capacity in Tranche Zero for a given utility. For projects that do not qualify for Phase One NEM, these projects will be compensated under the Phase One Value Stack tariff once it is effectuated by a VDER Phase One implementation Order.

Q: *The VDER Order refers to "projects for which 25% of interconnection costs have been paid" as the cutoff for inclusion in Phase One NEM. Can we interpret this to also include projects for which more than 25% of interconnection costs have been paid?*

A: Yes. Projects that pay <u>at least</u> 25% of interconnection costs within the 90 business day period will be eligible to be compensated under Phase One NEM. For CDG projects, eligibility will also be contingent upon available capacity in Tranche Zero for the given utility.

Q: *Will customers be required to install a new meter to be eligible for compensation under VDER Phase One?*

A: CDG, RNM and large, on-site projects compensated under Phase One NEM or the Phase One Value Stack must be equipped with a utility meter capable of recording net-hourly injections to the grid. Many existing projects will already have a meter meeting these requirements. For large, on-site projects, where an insufficient meter may already be preset, a project may interconnect under Phase One and an hourly meter should be installed as soon as practicable. If a customer, including a mass market customer, with an insufficient meter wants to opt-in to the Phase One Value Stack, that customer must arrange with the utility for appropriate metering to be installed.

Value Stack

Q: *Where can I find the actual dollar value of the value stack components?*

A: The utilities submitted draft calculations of the value stack components to the Department of Public Service on May 1. They are available at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0751&submit=Search+by+Case+Number. Please keep in mind that these are proposed calculations and figures, and not yet finalized by DPS.

Q: *Will there be a public comment opportunity regarding the terms and implementation of Phase One across different utility service areas.*

A: Yes. There was a Phase One Implementation Technical Conference for all stakeholders in Albany on April 5 and 6, 2017. Regarding the May 1, 2017 utility implementation filings, parties can file written comments.

Q: *Under VDER Phase One NEM for mass-market, how will monthly and annual excess generation be treated?*

A: On-site mass market customers compensated based on Phase One NEM will be billed each month based on their net monthly kWh consumption, as under the preexisting NEM rules. Any excess generation will be carried over to the next month as kWh credits. This carryover will continue across monthly and annual periods until the end of the project's 20 year Phase One NEM compensation term, at which point any excess credits will be forfeited.

Q: *How are large scale, on-site systems that are not associated with CDG or RNM configurations affected by the VDER Order?*

A: For VDER Phase One, "large" is defined as any customer with a demand (kW) meter or a customer on mandatory hourly pricing (MHP). Existing systems are not affected by the VDER Order, though they will be provided with the option of opting in to the Phase One Value Stack once it is available. New systems that meet the eligibility requirements will be served under Phase One NEM, which offers identical compensation to preexisting NEM except that Phase One NEM is limited to a term of 20 years. New systems not eligible for Phase One NEM, as well as systems that opt into the Phase One Value Stack, will receive monetary credits based on Value Stack calculations for net hourly injections.

Q: *Why are the commodity rates in the Order's Appendix A different from that found on a customer's utility bill?*

A: The estimates in Appendix A are based on a 36-month average for the years 2014-2016, and presented as a demonstration of how the utilities should calculate MTCs.

Q: *When will the methods and inputs to calculate the values of the Phase One Value Stack tariff be available?*

A: Detailed methods of calculation and inputs for several elements of the Phase One Value Stack, including energy and environmental values, appear in the VDER Order, as does the general structure for determining the remaining values. Utilities filed draft versions of their Implementation Plans and tariffs on May 1, 2017, which contain their proposals for calculation methods and inputs for other elements of the Value Stack. Parties will have an opportunity to comment on these in writing, and the Commission will rule on them as early as this summer. The utility proposals are available http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0751&submit=Search+by+Case+Number.

Q: *Will DPS Staff provide a procedure to value each piece of the Phase One Value Stack tariff without the use of insider utility knowledge?*

A: The Commission's March 9, 2017 Order provided the utilities with the critical regulatory information to design the Value Stack tariff to effectuate the Commission's determination on each piece of the tariff. The utilities filed draft tariffs publicly, along with work papers, on May 1, 2017. Staff and interested parties will review the tariffs and recommend any necessary changes to the Commission. The Commission will then determine which changes will be made and the final public tariffs will fully specify how future values will be calculated for each component of the Value Stack tariff.

Q: *Will the Value Stack calculation apply equally to all DER resources within a specific area of the grid, regardless of the utility rate a customer may be paying, provided they are injecting power to the grid at the same time of day?*

A: Yes. Any two projects compensated based on the Phase One Value Stack in the same area will receive identical compensation, with the limited exception of Market Transition Credits, which will only apply to eligible CDG projects and will vary between projects based on the tranche system, and the environmental value, which will be set for eligible projects for the entire compensation term based on the relevant value at the time of interconnection. The Service Classes applicable at the meter where the generator is located and the meters of off-takers, if any, will have no impact on the amount of compensation.

Q: *For the 460-hour approach of evaluating ICAP, would CDG subscribers only receive compensation for capacity values during those 460 hours?*

A: Yes. For this optional approach, systems would receive a much higher value per kWh injected, but only for those specific summer hours. This is intended to provide an enhanced incentive to produce during the more generation-capacity-constrained season of the year. However, for eligible intermittent technologies that prefer, the default approach is to simply credit a much lower value for any kWh that is injected at any point during the year.

Market Transition Credit (MTC)

Q: *For CDG projects with both residential and commercial subscribers, is it correct that residential subscribers will receive a bill credit that includes an MTC, and commercial subscribers will receive a bill credit that includes a DRV and no MTC?*

A: No. For a CDG project compensated under the Phase One Value Stack, the amount of monetary credits accrued will be based on the total value of the net hourly injections of energy over the course of the billing period, calculated based on the Phase One Value Stack. At the time of interconnection, the CDG will indicate to the utility what percentage of the project is dedicated to small customers and what percentage of the project is dedicated to large customers, as defined in the CDG Order, as part of indicating what percentage of the credits accrued each billing cycle will be given to each member. A percentage of the monthly injections equal to the percentage of the project dedicated to small, mass market customers that are not billed on demand-based rates will be valued based on the Phase One Value Stack including an MTC but not including the DRV, while the remaining percentage will be valued based on the Phase One Value Stack including the DRV but not including an MTC.

Q: *Is the MTC available for all CDG technologies?*

A: Staff is currently reviewing the question in more detail and in conjunction with the Commission's original Order adopting a CDG program, and anticipates resolving the issue within 30 days.

Q: *Will master-metered customers (e.g. EL8 tariff in ConEd territory) receive the MTC?*

A: Staff is currently reviewing the question in more detail and in conjunction with the Commission's original Order adopting a CDG program, and anticipates resolving the issue within 30 days.

Q: *How were the estimates of MTC calculated?*

A: The estimates of the MTC for S.C.1 customers, shown in Appendix A of the Commission's March 9, 2017 VDER Order, were calculated as described on pages 127 and 128 of the Order. The utilities filed draft Implementation Plans and tariffs with their calculations of the full set of MTCs, and work papers, on May 1, 2017, using those procedures described in the Order.

Q: *When will the percentage of residential off takers be determined for MTC allocation under the VDER Order?*

A: The March 9, 2017 VDER Order directed that "The MTC compensation shall reflect the actual mix of mass market customer members, as reflected by their percent entitlement to output credits" (p.128). As this mix may change over time, the utilities shall propose methods for implementing this requirement in their Implementation Proposals, to be filed on May 1, 2017.

Q: *Please define the following terms found in Appendix A: Net Revenue Onsite Mass Market Impact, Net Revenue CDG Impact, and Rev Shift 1.00?*

A: Appendix Table A of the VDER Order, "Estimated MTCs," was developed to allow the Commission to make informed decisions on Tranche sizes for CDG projects, and to provide an example of how the utilities should calculate MTCs. (The actual MTCs that will be used to credit CDG projects will be proposed by utilities in their May 1, 2017 filings, commented on by parties, and ordered by the Commission later this summer.)

The arithmetic: "Net Revenue On-site Mass Market Impact" = "MTC" – "VoD (estimated)" + E
"Net Revenue CDG Impact" = "MTC" – "VoD (estimated)"
"Rev Shift 1.00" = "MTC" – "VoD (estimated)"
(in other words, the same as "Net Revenue CDG Impact")

Explanation: The "Net Revenue Impact…," and "Rev Shift…" lines allowed the calculation of how the MWs in Table 3 (p.87 of the VDER Order) and Table 4 (p.131 of the VDER Order) compared to the 2% bill impact target. As the footnote in the Appendix A Table indicates, on-site Phase One NEM has a larger revenue impact than Phase One CDG, because onsite NEM is not metered and injected hourly, thus does not provide Tier 1 REC credit toward utility revenue requirements. However, both on-site mass market and CDG production will provide some reduction in local distribution costs. Although these elements of the Value Stack will not be set until the utility May 1st filings, and summer Implementation Order, Table A provides an estimate of this value ("VoD (estimated)") and this is subtracted from MTCs before the revenue impact for onsite mass market, or CDG Tranche, is estimated.

Q: *Are the work papers associated with the tables and appendices included in the Order available? Going forward, will utilities be required to provide work papers to support their final MTC calculations to all stakeholders?*

A: The utilities shall file their work papers with their Implementation Proposal filings on May 1, 2017. These are the work papers that would be the most complete, and most accurate, to review for the actual VDER tariffs that would be implemented.

Tranche Design

Q: *Please explain the peak load metric used alongside the 2% net annual revenue impact to determine tranche sizes?*

A: The incremental 2% net annual revenue impact per utility is used as a guide for establishing MW capacity allocations per utility to accommodate new mass market projects and new CDG projects in VDER Phase One. For new mass market projects, the MW capacity allocation per utility is based upon 2 years of projected mass market growth and is anticipated to accommodate growth of this market segment through January 1, 2020. For new CDG projects, the peak load metric is used to establish a total MW capacity allocation per utility for Phase One. After accounting for the MW capacity allocation for mass market projects, a percentage of 2016 peak load was selected for each utility to establish total MW capacity allocation for CDG while remaining beneath the 2% net revenue impact boundary. For O&R and ConEdison 4%, of 2016 peak load was selected. For CHG&E, National Grid, NYSEG and RG&E, 7% of 2016 peak load was selected.

Q: *In O&R and NYSEG territories, the capacity of CDG projects that have already paid at least 25% of interconnection costs prior to the date of the Order was larger than the size of Tranche 0/1. Were all of these projects be included in Phase One NEM?*

A: No. Projects that paid at least 25% of interconnection costs prior to the date of the VDER Order were placed in tranches based on the date and time stamp of their payment. Once enough projects had been placed in Tranche 0/1 to fill it in a given utility territory, subsequent projects were placed in Tranche 2. Projects placed in Tranche 2 or 3 will receive compensation based on the Phase One Value Stack with the applicable MTC.

Q: *How will utilities be required to handle attrition within tranches, such as handling projects that initially reserve capacity by paying 25% of their interconnection costs and then are not built, or decline in capacity for some reason?*

A: The utilities have not been directed to take any specific action if projects attrite from any particular tranche. As directed in the VDER Order, in order to ensure that activity under the VDER Phase One meets stakeholder expectations and state goals, as well as to monitor unintended consequences, Staff shall conduct a review of initial progress and file a report on that progress within six months of the Order. Staff anticipates that this review will provide an appropriate opportunity to reflect upon progress or attrition beneath the CDG tranches and to consider any actions that may be deemed appropriate.

Q: *What happens when a utility's Tranche 3 is full?*

A: Upon hitting 85% of the utility's total MW capacity allocation for CDG tranches, the utility shall provide notice to the Commission, and the Commission will take up consideration of any action that may be deemed appropriate. Until the Commission takes action, any additional CDG projects that pay at least 25% of their interconnection upgrade costs, or execute an interconnection agreement is such costs are not applicable, will be placed into Tranche 3 and will be entitled to compensation under the Phase One Value Stack with the applicable MTC for the 25-year term. This practice will continue up to and beyond the Tranche 3 MW capacity allocation until the Commission acts.

Q: *Do all CDG MWs count toward the tranche MWs, or only the portion serving mass market customers and receiving MTCs?*

A: All CDG MWs count towards the available tranche MWs.

Q: *Given that the CDG requirements allow ESCOs to participate as CDG developers, will these entities have the ability to obtain revenue from both QF payments and CDG payments?*

A: The developer of any individual project must elect to either interconnect that project as a CDG project or interconnect it for wholesale sale of electricity as a Qualifying Facility (QF) under the Public Utility Regulatory Policies Act (PURPA). A CDG project must use all of its generation to serve its members, and therefore would have no remaining energy to sell as a QF. A developer can own multiple projects, some of which are CDG projects and some of which are QFs.

Renewable Energy Credits (RECs)

Q: *Where can I find a simplified overview of the treatment of RECs in NYS?*

A: Please see the NYSERDA NYGATS page at https://www.nyserda.ny.gov/All-Programs/Programs/NYGATS.

Q: *What is the process for developers or customers related to the Customer-Retention-Option for Renewable Energy Credits (RECs)? The Order states that, "unless customers make a joint non-revocable election at the time of interconnection to opt out" they will be enrolled in the Interconnecting-LSE- default. How will this be implemented?*

A: The utility will collect this information at the time of interconnection.

Q: *Can legacy ADGs, who continue to participate in NEM, market these previously controlled RECs* *through NYGATs or the open market?*

A: If the question refers to selling the previously controlled RECs, then no, this is not permissible. However, customers enrolled in NEM under pre-existing NEM tariffs, assuming that there is no legacy RPS Main Tier contract signed with NYSERDA, are able to get minted non-transferable (un-tradable, unsellable, and non-monetizable) certificates for deposit and retirement in a customer's NYGATS account. While not tradable, these minted certificates will be eligible to satisfy various voluntary environmental and sustainability certification programs.

Q: *Does the Commission decision on treatment of behind the meter (voluntary) RECs (i.e. non-transferable, non-tradeable, not eligible for Tier 1) also apply to RECs purchased as part of a bilateral PPA (e.g., as part of a corporate purchase of bundled renewable energy)?*

A: Yes. The customer who has the rights and claims to any environmental attributes associated with the project would be able to have certificates minted in NYGATS for retirement in that customers account.

Q: *For companies that require additionality in their renewable procurement decisions, will the Commission consider altering its decision to count voluntary RECs as part of the 50% target and to use these RECs to reduce the Tier 1 obligation?*

A: Pursuant to the decision in the VDER Order, RECs retained for voluntary additionality purposes will not be counted towards LSE Tier 1 obligations. However, they will be counted towards the State's 50% by 2030 renewable energy goal, because that aggressive target is based on the contributions of all actors. The decisions are consistent with the comments of the Center for Resources Solutions, the entity that administers the Green-e certification program, regarding how RECs should be treated to ensure that customers are able to meet additionality standards.

Q: *Where can I ask questions about RECs in NYS?*

A: Please email attributes@nyserda.ny.gov.

Q: *Are any non-transferable RECs created in NYGATS for non-exported generation to be consumed on site?*

A: Yes. NYGATS will mint non-transferable certificates for deposit and retirement in a registered customer's account in NYGATS.

Q: *If an existing project that has received incentives from NYSERDA in the past were to opt into the Value Stack, would that include the value of E?*

A: It depends on the vintage of the generator. The threshold eligibility date (TED) for eligible Tier 1 facilities is January 1, 2015. A project that came on-line prior to that date but opted into the value stack would not receive the E value because the project would not be Tier 1 compliant and the value of E is associated with Tier 1 eligible certificates. Conversely, if the project came on-line after the TED, then it would receive the value of E.

Miscellaneous

Q: *Where can DER developers and customers go to find information on CDG tranches, the Phase One Value Stack numbers, and additional information pertaining to the Order?*

A: . This page contains a tranche capacity chart that will be updated biweekly. As NYSERDA and DPS develop additional resources, we will post them to this site.

Q: *What is the Commission's current position on the applicability of current Uniform Business Practices to DER and CDG developers and providers?*

A: The Uniform Business Practices (UBP) apply to ESCOs, defined in the UBP as "entit[ies] eligible to sell electricity and/or natural gas to end-use customers using the transmission or distribution system of a utility." Development and sale of DER products and services, including CDG credits, does not fall within this definition. As directed in the Order, Staff is working on a revised DER oversight proposal for Commission consideration.

Q: *How will projects be compensated for energy that is generated and instantaneously consumed on-site as opposed to being exported to the grid?*

A: Under the Phase One Value Stack, generation that is exported to the grid on a net-hourly basis will be compensated according to the Value Stack methodology. Energy that is generated and instantaneously consumed on-site and behind the meter of a customer will be treated as load reduction and will therefore offset a customer's consumption and volumetric (i.e., per kWh) charges associated with that consumption.