Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding

15-E-0751

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1 Introduction

1.1 Precise DER Valuation and Compensation is Essential to New York's Energy Future

1.1.1 Reforming the Energy Vision in New York

Compelled by technology changes, consumer demands, and environmental exigencies, the State of New York is undertaking substantial efforts to "reform the energy vision." These efforts are transforming New York's energy economy to one that is consumer centric, economically and environmentally efficient and sustainable, and embraces market and business model innovation. Under Governor Cuomo's leadership, the Public Service Commission's Reforming the Energy Vision proceeding (REV) is a foundational initiative of the State's efforts. REV aims to "transform New York's electric industry, with the objective of creating market-based, sustainable products and services that drive an increasingly efficient, clean, reliable, and customer-oriented industry."[1]

REV embodies the fundamental precept that clean energy deployed at scale holds the potential to address the pressing environmental and energy challenges of our time while providing enormous economic opportunity for New York. REV further embraces the commitment to reexamine and realign regulatory practices and policies that accelerate the successful and sustainable transition to a modern clean energy economy that can benefit all New Yorkers.

Today, the customer side of the grid represents an enormous and largely untapped resource to optimize value throughout the electricity system. REV will establish markets so that customers and third parties can be active participants, to achieve dynamic energy management on a system-wide scale, resulting in a more efficient and secure electric system, including better utilization of bulk generation and transmission resources.

As a result of this market animation, the role of distributed energy resources (DERs), including end-use energy efficiency, demand response, distributed storage, and distributed generation, will become integral tools in the planning, management and operation of the electric system. By exercising choices made available by an animated market, customers can create new

[1] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Instituting Proceeding (issued April 25, 2014).

value opportunities while they provide new resources to the system. Harnessing DERs for the service of the broader system will reduce system costs overall for the benefit of all customers.

The modernization of New York's electric system will involve a variety of products and services that will be developed and transacted through market initiatives. Products, rules, and entrants will develop in the market over time, and markets will value the attributes and capabilities of all types of technologies. As Distributed System Platform (DSP) capabilities evolve, procurement of DER attributes will develop as well, from a near-term approach based on requests for proposals (RFPs) and load modifying tariffs, towards a more sophisticated auction approach.[2] The market construct aims to support the proliferation of cost effective and innovative clean energy related products and services provided by all service providers, in support of customer energy needs as well as grid support services. Products transacted and purchased by the DSP will be focused on two areas:

- distribution grid services that will enable the DSP to optimize the distribution system, including through offsetting or deferring both immediate and long-term costs; and
- aggregated energy resources and ancillary services that can be sold to the New York Independent System Operator, Inc. (NYISO) or through NYISO markets to optimize the generation and transmission system.

An integrated grid that enables dynamic operation of DERs will require more accurate pricing for the products and services that such DERs will provide. Such products and services will evolve as the current construct is unbundled and the necessary tools and capabilities to determine the value of such products and services are developed. This will enable the utilities to continue to operate a reliable system in the most efficient manner while providing value to customers and society. The EPRI Integrated Grid Paper[3] provides a reference point for the types of products and services envisioned under an integrated system, including the following examples:

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2 Case 14-M-0101, supra, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Track One Order).

3 Electric Power Research Institute, The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources (February 14, 2014), available at http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002002733.

Distribution voltage support and ride-through – DERs can provide distribution grid voltage and system disturbance performance by riding through system voltage and frequency disturbances to ensure reliability of the overall system, provided there are effective interconnection rules, smart inverters, or smart interface systems.

Optimize distribution operations – This can be achieved through the coordinated control of distributed resources and the use of advanced inverters to enhance voltage control and to balance the ratio of real and reactive power needed to reduce losses and improve system stability.

Improve voltage quality and reduced system losses – Included in this are improved voltage regulation overall and a flatter voltage profile, while reducing losses.

Defer capacity upgrades – With proper planning and targeted deployment, the installation of DERs may defer the need for capacity upgrades for generation, transmission, and/or distribution systems.

Improve power system resiliency – Within an integrated grid, distributed generation can improve the power system's resiliency, supporting portions of the distribution system during outages or enabling consumers to sustain building services, at least in part.

Participate in demand response programs – Combining communication and control expands customer opportunities to alter energy use based on prevailing system conditions and supply costs.

Reduce environmental impacts – Renewable distributed generation can reduce power system emissions, and an integrated approach can avoid additional emissions by reducing the need for emissions-producing backup generation. Also contributing will be the aggregation of low-emissions distributed resources such as energy storage, combined heat and power, and demand response.

This new level of customer and third party participation requires more precise price signals for these new products and services that will, over time, convey increasingly granular system value further enabling increasingly accurate compensation and driving informed and therefore effective investment decisions. As described in the Commission's Order Adopting a Ratemaking and Utility Revenue Model Policy Framework,[4] customers and other market participants must have sufficient information about value creation potential to make the best choices about how they purchase and use power, and how they invest in and use DERs. Electricity retail pricing experienced by customers must provide efficient value signals, both in the rates paid by customers for utility service, and in compensation earned by customers for

[4] Case 14-M-0101, supra, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) (Track Two Order).

value that energy management and distributed generation can provide to the system. Thus, as the Commission stated in its Order Establishing a Community Distributed Generation (CDG) Program,[5] achieving a more-precise articulation of the value of DERs is a "cornerstone REV issue."

1.1.2 The Need for More Precise Valuation and Pricing

To date, net energy metering (NEM) has been an important and effective tool in fostering the growth of New York's distributed generation industry, especially solar photovoltaic (PV) generation. NEM has provided a simple and easy to understand compensation mechanism as an approximation for the system contribution made by customer-sited generation. NEM is a powerful mechanism for supporting an emerging market and providing customers with an intuitive value proposition. However, especially when combined with traditional volumetric rate structures, NEM provides an imprecise and incomplete signal of the full value and costs of DERs. NEM therefore provides insufficient information on which to base informed investment and usage decisions that could benefit both the system and customers under REV. As a result, investment in new DER capacity is often made without regard to how the design, siting and operation of those resources can maximize benefits to the electricity system overall.

The purpose of this ongoing proceeding is to develop accurate pricing for DERs that reflects the actual value DERs create. The distributed grid that REV envisions requires far greater DER penetration than currently exists. Indeed, some DER values may not be fully available until there is sufficient penetration to allow a dynamic, transactive system managed by a DSP. Reaching this sort of distributed system requires business models and pricing that offer compensation mechanisms and accurate signals to encourage utilities and DER developers and customers to design, site, and operate their projects to optimize the economic, environmental, and reliability value of the integrated networks for the benefit of individual actors and all consumers. The goal of this proceeding is therefore to enable an increase in both overall DER

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[5] Case 15-E-0082, Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program, Order Establishing a Community Distributed Generation Program and Making Other Findings (issued July 17, 2015) (CDG Order).

penetration and the benefits that DER installations, individually and collectively, provide to the system by making compensation accurately match those benefits.

While deployment of DERs provides a long-term asset to the system, the NEM construct does not enable accurate compensation for all the value streams DERs offer, including those that today may not be quantifiable or even identified. In the dynamic and transactive market envisioned by REV, more precise and granular pricing will be critical to better value and compensate the future products, capabilities, and services provided by DERs. Failing to identify and compensate for the value of DERs to the grid limits the incentive to add smarter integration technologies, such as smart inverters, and to motivate customers to make investment decisions that would mutually benefit the customer and the grid. At the penetration levels of DERs that REV seeks to enable, future markets will depend on DER facilities that have the technical capability to interact with the DSP to enhance system operations. Compensation mechanisms must therefore be developed to enable the realization of those values. The failure to install these capabilities in new projects represents a lost opportunity and therefore a cost for the system and all New York ratepayers.

At low levels of DER penetration, the economic inefficiencies resulting from the incomplete price signals embedded in NEM are less consequential, but as adoption increases, these potential misalignments—and the uneconomic effects associated with them—will increase. Under REV, NEM will insufficiently drive the penetration and intelligent design, siting, and operation necessary to establish an integrated and dynamic grid managed by the DSP for the benefit of ratepayers. While the market structure, products, and transactional mechanisms will evolve over time, the successfully animated market will need to provide clear short and long-term signals to customers as to the benefits and costs of their market activity. A transition to more-precise DER valuation and compensation is necessary now.

Price signals must enable DER providers to monetize products and services that will provide value to the transmission and distribution systems and thus to all customers. These signals must offer the information and incentives that DER providers need to locate, size, and design their projects based on the benefits and costs that will result from a particular DER interconnected in a particular location. Providing these price signals will enable effective and efficient investment in and utilization of DERs, which will expand the benefits that these resources provide to the electric system through improved design and enhanced network capability. Doing so will require more granularity in valuation and pricing along key dimensions that differentiate value in planning and operating the electricity system, including timing, location and performance.

Accurate and granular price signals are also critical to ensuring efficient market operations. The current market and price designs were developed to prioritize the dispatch of bulk power resources based exclusively upon physical and economic constraints. The local marginal pricing applied in the wholesale markets does not segregate out the ancillary supports, load shifting, and environmental and performance benefits that are essential design features of a fully optimized bi-directional power system and decarbonized network. Under a modernized grid wherein the DSP plays an active role in coordination with the Independent System Operator, accurate and granular pricing of all of the monetizable elements of the networks will help ensure that the markets are efficiently designed and operated. Since under the REV model utility compensation will be based, in part, on their ability to use DERs and other third party investments to ensure efficient and reliable operations, the accurate pricing of DERs will enable to the PSC to monitor the retail market to ensure that fair and economic design for, reliance on, and dispatch of DERs is occurring.

To date, the Commission has initiated several REV-related efforts to enable more precise valuation and pricing, including the development of a Benefit Cost Analysis (BCA) framework and utility Distributed System Implementation Plans (DSIPs). The Commission ordered the creation of the BCA framework to ensure “an accurate and consistent analysis methodology” for comparing potential investments that will enable an animated market at the distribution system level. The Framework informs a range of utility expenditures including the procurement of DERs via selective processes and tariffs. It establishes a starting point for valuing DERs by delineating the approach for estimating the traditional electricity system costs that can be avoided.

In conjunction with the creation of the Framework, the Commission ordered utilities to create BCA Handbooks that describe and quantify the utility's benefit and cost components, and their respective application, when evaluating DER projects for possible development. The BCA Framework also serves to inform utility DSIP filings, which “identify [utility] system needs, proposed projects for meeting those needs, potential capital budgets, particular needs that could be met through DER or other alternatives, and plans for soliciting those alternatives in the marketplace.”

Together, the BCA Framework works in coordination with the DSIPs to lay important groundwork for the development of improved valuation and compensation. Utilities have filed the BCA handbooks and Initial DSIPs, which are open for public comment.[6] A Supplemental DSIP, filed jointly by the utilities, is expected in November 2016. When finalized, utility BCA Handbooks and DSIPs will provide key inputs for the continued evolution of DER valuation and compensation.

1.1.3 Determining the Value of Distributed Energy Resources and Developing Appropriate Compensation

Efficient competitive pricing reflects the marginal costs, including external (or "societal") costs, which are incurred or avoided for specific goods or services, when and where these are provided. The significant benefits that clean distributed generation provides to the electric system and society fall into four broad and general categories:

Category	DG Value Provided:
Avoided System Energy Costs (including avoided zone-to-zone transmission value and avoided losses)	per kWh, varies by hour and loacation
Avoided Generation Capacity Costs (including avoided reserves per kW of load and avoided losses)	per kW coincident with System Peak
Delivery Costs	per kW coincident with local (e.g. network) peak
Avoided Societal Damage/Mitigation Costs*	typically per kWh*

*Per the BCA Framework Order, this report addresses the net damage costs (or in the case of NYGATS Certificates, the avoidable mitigation costs captured by Clean Energy Standard Tier 1 Renewable Energy Certificate (REC) prices) that are monetized per kWh. Other externalities, such as those associated with environmental justice issues, are more specific, discrete and local and should be addressed by utilities (for example, in Non-Wires Alternatives (NWA) BCA analyses) rather than generically in monetized tariff pricing.

In theory, all resources that deliver these benefits—when, where, and in the quantitative units required—should receive the same price signal reflecting that precise marginal value. This is what is meant by "technology neutrality." This, however, does not mean that there would be no distinguishing among technologies; it means that any distinguishing among technologies will reflect the different capabilities of technologies to deliver these values.

[6] Case 16-M-0412, In the Matter of Benefit Cost Analysis Handbooks, Notice of New Case Number and Soliciting Comments on the Benefit-Cost Analysis Handbooks (issued July 27, 2016); Case 16-M-0411, In the Matter of Distributed System Implementation Plans, Notice of New Case Number and Soliciting Comments on the Initial Distributed System Implementation Plans (issued July 26, 2016).

The effort to better identify, quantify, and monetize more granular costs and values at the distributed level has really just begun. Achieving perfectly efficient, optimally granular, and instantaneously dynamic pricing is a necessary goal, but not immediately achievable given today's costing methods, available data, current utility tariffing, and the technology infrastructure in place. This is especially true under NEM, where the de facto compensation amount, for example for residential customers, is the volumetric, or per kWh, portion of default retail rates. As has been discussed, default mass market rates have been designed to address many issues other than setting efficient price signals for DG development.[7]

While these issues remain important considerations for retail rate setting, they have not resulted in efficient price signals for widespread DER development. First, because simple mass market rate designs only have a fixed charge and a per kWh charge, and because many fixed distribution system costs are recovered through the kWh charge, NEM price signals will tend to overstimulate kWh-based values and understimulate kW-based values. Second, default mass market retail rates do not reflect the time-varying differential in commodity prices. Third, retail delivery rates are set in a "postage stamp" fashion, rather than reflecting location-based cost causation. Relatedly, retail delivery rates are fairly static and, thus, even if differentiated by location at a given point in time, would have difficulty keeping pace with changing locational distribution cost causation. Fourth, retail rates have no way of valuing any of the other benefits DERs can offer, such as location reliability, demand shifting, flexible operation, and quick response. Fifth, any de facto price signal to reflect the environmental consequences of consumption (and, thus, the benefit of lower consumption) is coincidental, based solely on the extent to which retail kWh charges happen to exceed private kWh-related costs, and not any calibration to monetized environmental damage or mitigation costs.

One final issue is particularly challenging in a regulated utility setting. Many DER options are long run investments, competing against a combination of spot purchases and traditional, long run utility investments, the latter receiving regulated rate treatment, with all that such treatment entails. In more competitive sectors, market participants react to short run and long run price signals, and balance risks with a combination of spot purchases and sales, and

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[7] See, e.g., Case 14-M-0101, supra, Track Two Order.

long run contracts and investments. Retail utility tariffs, however, represent a blended combination of short-run and long-run, and competitive and regulated, price signals.

Despite, and sometimes because of, these imperfections, NEM has successfully stimulated DER deployment and access to the accompanying, albeit incompletely unbundled, benefits. Efficient businesses and customers will naturally try to minimize the costs to achieve the benefits that NEM price signals provide. Thus, one should not be surprised that some potential values that DERs might otherwise provide have not materialized under the existing NEM construct and current mass market rate design. Further, although the DSIP, BCA Framework and related Non Wires Alternative RFPs under REV seek to address the long run planning aspect of some of the issues raised above, any transition towards more accurate pricing also must acknowledge and address the stable price signal that NEM has provided in enabling the investment in these smaller, widely distributed, long-lived resources.

Figure 1 below depicts this situation graphically for a hypothetical utility NEM rate and a hypothetical 2 MW PV system in upstate NY. The first bar represents the credit that NEM currently provides for each kWh the PV system produces. (It is broken down into the retail rate's most significant kWh components: commodity, delivery, and public benefit surcharges). Under this compensation scheme, there is no incentive to sacrifice kWhs for kWs (say, by angling the system differently), even if there is system or distribution capacity value to doing so. Nor is there any reason to locate where there is even more value to the system in that location or to add storage (even if the reliability, VAR and energy arbitrage values exceed the cost of said storage). Thus, the second bar represents the hypothetical collection of values such incomplete price signals might produce.[8] Alternatively, a compensation methodology that better combines and balances per kWh price signals with kW price signals aligned with the system peak, other kW signals aligned with local peaks, and price differentials to reflect temporal and locational differences in value could encourage DG providers to incur the costs necessary to produce the much higher value stack represented by the third column. It should be noted that the two "value" bars reflect the *price*, that is, the marginal cost, of potential value categories that would be

8 Even though all values are expressed in "per kWh" terms for graphing purposes, the capacity values were first calculated by the respective peak contribution provided per kW.

received per kW or kWh (although shown averaged per kWh for presentation purposes). This is not addressing the *quantity* of each benefit provided, which may change to receive some of the enhanced values in the "REV Distributed Gen. Value" bar. For example, a PV system owner might receive more value by tilting the system, which would sacrifice some daily kWh to achieve greater values through coincidence with local and system peaks reflected in increased energy values through Locational Based Marginal Pricing (LBMP), installed capacity (ICAP) values, and distribution system values.

In addition to these retail issues, there remain administrative "seams" between wholesale and retail markets that cause compensation to diverge from the value that is created. An extremely large portion of the value created by distributed resources derives from them acting as "load modifiers" to the commodities and services that retail load-serving entities (LSEs) must purchase from the wholesale market. The most straightforward administrative approach to crediting DERs for this portion of benefits is to reflect the actual impact such load modification has on the bills the NYISO renders to LSEs. Unfortunately, some of the administrative mechanisms employed by the NYISO to allocate costs for such commodities and services to LSEs do not precisely follow the actual cost causation or value creation. In those instances, the wholesale bill rendered to the LSE will not accurately capture the benefit provided by distributed resources.

One such commodity is "Installed Capacity," or "ICAP." The NYISO's administrative mechanism for assigning a year's responsibility for ICAP to LSEs is to base it on each LSE's peak load in the actual single system peak hour of the prior year. In turn, utilities base each retail hourly customer's ICAP responsibility on the customer's metered load in that same peak hour (known as the customer's individual "ICAP Tag").[9] Unfortunately, that ex post single peak hour isn't always the best indicator of the current year's load's impact on the need for more or less installed capacity, or its underlying value impact to resource adequacy. While some in the past have suggested alternatives, such as spreading the load responsibility to more than one single peak hour, this issue has never risen up to a high enough priority level to be addressed by NYISO working groups.

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[9] Staff has been a strong proponent of such an approach, as it reflects the actual cost impact on the LSE.

Another example is the NYISO's charge for ancillary services such as regulation, voltage support, synchronous and non-synchronous reserves, and black start. The method that the NYISO uses to allocate these costs to LSEs is insensitive to actual LSE load levels. Thus, utilities have argued that distributed resources provide no reduction to their NYISO bills and should receive no credit even if, in actuality, some level of these resources generally reduce the need for such services over time. One utility suggestion is that a distributed resource become a direct provider of such services to the NYISO to receive credit for the service. However, it is typically impractical or impossible for smaller distributed resources to become direct providers to the NYISO. Staff intends to lead and facilitate discussions among DER companies, the utilities, and the NYISO to develop recommendations to address these issues.

Of course, such dramatic changes from the existing compensation framework to an improved one cannot be achieved overnight. Further, recognizing the conceptual drivers of various types of costs is one thing; designing practical, tariff-based methods and systems to signal and compensate for those values is another. Finally, there will continue to be a tension between the need for dynamic price signals reflecting short run changes to marginal costs and the long run (investment) nature of some of the costs that are potentially avoidable and that, in turn, need to be incurred in order to avoid them. Nonetheless, as we work to improve retail rate design, the granularity of retail and wholesale price signals, and the proper pricing of wholesale commodities and services, the methods and systems for compensating DERs should remain flexible enough and will continuously evolve to incorporate some or all of these improvements.

Below, Staff presents recommendations (with alternatives) to address these and other transitional and balancing issues.

FIGURE 1


NEM Compensation vs. DG Value
Hypothetical 2 MW PV
$/kWh
$0.000
$0.020
$0.040
$0.060
$0.080
$0.100
$0.120
$0.140
$0.160
$0.180
$0.200
$0.16/kWh
Surcharges, $0.010
Delivery, $0.080
Commodity, $0.070
$0.13/kWh average
"Avoidable D", $0.020
E, $0.030
ICAP, $0.030
LBMP, $0.050
LBMP Coincidence, $0.010
ICAP Storage, $0.030
D Reactive, $0.005
D Storage, $0.010
D Location, $0.010
"Avoidable D", $0.020
E, $0.030
ICAP, $0.030
LBMP, $0.050
Retail NEM Credit
Old Distributed Gen. Value
REV Distributed Gen. Value
Notes:
1. The "retail NEM Credit" column represents compensation NEM provides per kWh.
2. The "Old Distributed Gen. Value" column represents the potential value that may be provided under NEM price signals, when the kWh and kW benefits are calculated and then expressed on a per kWh basis
3. The "REV Distributed Gen. Value" represents the potential locational kW and kWh value that could be created if NEM price signals are replaced with more efficient price signals.

1.1.4 The Transition Path

To ensure forward progress that supports New York's emerging DER markets while avoiding policy cliffs that could hinder DER business model development, the Commission has required that the design and implementation of changes in DER valuation and compensation begin now.[10] The Commission has also recognized that necessary technical capabilities, including the planning and operational tools that will be key to more precise valuation and transaction of system benefits and costs, are in the early stages of development. As the Commission stated in its Order Adopting Regulatory Policy Framework and Implementation Plan, DER valuation and compensation will be an ongoing process that will proceed in tandem with technical and market capabilities: As market capabilities evolve, procurement of DER attributes will develop as well.[11]

To balance the need for action with the need for continual adaptation, the Commission ordered the development of an "interim methodology" as the initial step toward more-precise DER valuation and compensation.[12] As such, an interim (or "Phase One") value of DER (VDER) methodology will be developed initially, at which point the development of a Phase Two methodology will begin immediately. The Phase One VDER methodology should seek to take significant first steps toward more-precise valuation and compensation, recognizing and operating within the constraints that continue to exist. At a minimum, the Phase One methodology should establish a valuation and compensation foundation that can evolve as new knowledge and capabilities are developed. It should also recognize environmental attributes, while providing for a market transition consistent with the principles of gradualism and predictability. Moving from Phase One to Phase Two methodology will reflect an ongoing process that incorporates the ever increasing capability to identify and value benefits, leveraging

[10] Case 15-E-0407, Petition of Orange and Rockland Utilities, Inc. For Relief Regarding Its Obligation to Purchase Net Metered Generation under Public Service Law §66-j, Order Establishing Interim Ceilings (issued October 16, 2015) (NEM Interim Ceilings Order).

[11] Case 14-E-0101, supra, Track One Order at 33.

[12] Case 15-E-0407, supra, NEM Interim Ceilings Order at 14.

the expanded set of tools and data produced through parallel REV efforts. This iterative approach will enable a smooth transition to improved valuation and compensation.

1.2 Developing This Staff Report and Recommendations

1.2.1 Procedural Background

In its order establishing a community distributed generation program, the Commission directed Staff to develop a report and recommendations on valuation of distribution system benefits provided by DERs.[13] Subsequently, in the context of establishing floating capacity limits for NEM, the Commission directed the Secretary to issue a notice of a new proceeding to establish a new regulatory approach to valuing DER products and designing rates for DER providers which would lead to potential alternatives for NEM.[14]

The Commission did not establish a deadline for developing a new methodology for valuing DERs, instead noting that the process would likely involve a long term effort. But the Commission expressed its expectation that more precise interim methods for valuing DER benefits and costs, and designing rates and valuation mechanisms, could be achieved by December 31, 2016.[15] The Commission said such measures could serve as a bridge until an approach based on the "value of D" is more fully developed and implemented.[16]

By notice issued December 23, 2015, the Secretary commenced a proceeding to (1) identify for the Commission an interim approach to valuing DERs including a transition plan for moving from NEM to DER valuation that can be adopted prior to December 31, 2016; and (2) establish a methodology and process for determining the full value of DER for the purpose of developing DER compensation mechanisms built upon an "LMP+D" approach. In that notice, the Secretary invited interested parties to file comments, on or before April 18, 2016, in the form

13 Case 15-E-0082, supra, CDG Order at 32–33.

14 Case 15-E-0407, supra, NEM Interim Ceilings Order at 14. The CDG Order had directed Staff to file a report on the outcome of this process by January 15, 2016. That deadline was deemed to have been subsumed by the matter undertaken in the instant proceeding.

15 Case 15-E-0407, supra, NEM Interim Ceilings Order at 15.

16 Id. at 9, 11, & 15.

of responses to a number of specific questions and in the form of detailed proposals for an interim successor to NEM tariffs in New York State.[17]

Pursuant to that notice, a preliminary conference was held on January 7, 2016, to provide interested parties an opportunity to ask questions and seek clarification about the process and scope of the case. Thereafter, on or about April 18, 2016, a large number of interested parties filed comments and detailed proposals.

On April 22, 2016, a notice was issued announcing a technical conference to be held on May 10, 2016, to allow some of the parties that submitted initial filings to make presentations on their filings and allow other parties a forum for asking clarifying questions.[18] That notice also allowed parties to make filings on or before June 10, 2016 in response to the initial filings in the case.

At the technical conference on May 10, 2016, presentations were made by New York University School of Law, Institute for Policy Integrity/Environmental Defense Fund; Solar Energy Industries Association/Vote Solar; Advanced Energy Economy Institute/ACENY/NECEC; and the Solar Progress Partnership. At the end of the technical conference, the parties were invited to submit comments on the procedure to be employed in this proceeding, given its goals and purposes. A number of parties timely filed comments, and procedural recommendations ranged from a fully-litigated proceeding to a collaborative process.

Based upon a review of those filings, on May 25, 2016, the Administrative Law Judge issued a procedural ruling adopting an informal and collaborative process, consisting of meetings and conferences on notice to all active parties and structured to promote the development of joint recommendations for Commission action. Parties would be encouraged to share information as appropriate to facilitate meaningful discussions and compromise in order to promote agreement to the greatest extent practicable.[19]

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[17] Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources, Notice Soliciting Comments and Proposals on an Interim Successor to Net Energy Metering and of a Preliminary Conference (issued December 23, 2015).

[18] Case 15-E-0751, supra, Notice of Technical Conference (issued April 22, 2016).

[19] Case 15-E-0751, supra, Procedural Ruling (issued May 25, 2016).

On or about June 10, 2016, comments were filed in response to the initial filings made on April 18, 2016. The first collaborative conference was held on June 14, 2016, and subsequent conferences were held on July 6, July 19, August 4, August 23, September 7, September 20, and October 7, 2016. To minimize the burden on parties, the meetings were held alternately at the Commission's offices in Albany and New York City, and attendance via teleconference and webcast was permitted. To facilitate the process, Staff created a number of straw proposals that were solely intended to facilitate discussion and explore approaches that reflected the discussions of the collaborative. Subsequently, participating parties provided input to the straw proposals at collaborative conferences as well as smaller working groups established to address specific topics within the straw. The public comment period will offer an additional opportunity for parties and other stakeholders to continue the discussion.

1.2.2 About This Report

This Report culminates the initial Phase One work of the stakeholder collaborative. Authored by Department of Public Service (DPS) Staff, the report presents options and recommendations that were informed by the comments and contributions of the participating parties. While the Commission has recognized that DERs comprise a full range of energy resources,[20] the focus of the report and the stakeholder collaborative was technologies currently eligible for NEM. However, additional DER technologies were considered by the collaborative and this report (see Section 2.2, below, for more detail).

The collaborative discussions and the options and recommendations presented by Staff were shaped by the Commission's established timeline for the presentation of a proposed interim methodology in 2016. To enable Commission consideration of the interim methodology in January 2017, the report had to be finalized for issuance and public comment in October 2016.

A wide range of views and perspectives were represented over the course of the stakeholder collaborative. The process enabled alignment and, to differing extents, some agreement and common ground on issues and principles. At the start of the process, Staff and parties developed a set of first principles that a new methodology should provide:

- Increased **precision** and **alignment** of valuation of benefits and costs from DERs;

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20 Including distributed generation, demand response, energy efficiency, and energy management technologies.

- **Clarity** and **simplicity** to ensure customers and developers can use and respond to the methodology;
- **Certainty**, **predictability**, and **stability** to allow market and financing efficiency;
- **Gradualism** to avoid sudden disruption of DER markets;
- **Technology neutrality** that accounts for the unique characteristics and performance of different technologies;
- **Support for public policy** to acknowledge the goals of multiple jurisdictions;
- **Breadth** to include a greater number of value components than are present under NEM;
- **Transparency** of valuation methods;
- **Flexibility** to allow valuation methods to evolve over time;
- **Equity** and **fair access** for all customers to the full range of DER technologies; and
- **Customer affordability**, balancing between support for DER market growth and impacts to ratepayers.

Staff believes the recommendations presented in this report reflect these principles. Further, the recommendations are shaped by the recognition by Staff and all parties that currently available tools and data may prove imperfect for calculating certain value streams. Thus, the recommended Phase One VDER methodology is designed to accommodate the need for market transition to avoid a sudden disruption in the DER market and ensure that imperfect value calculations do not undermine the intent to send more-accurate price signals about the benefits and costs that DERs provide to the grid.

While this report addresses recommendations for a Phase One methodology, there is a consensus among Staff and the active parties to the proceeding that work on Phase Two can and should begin immediately following issuance of this report. In addition, there is a consensus that a Phase Two methodology can and should be adopted by the Commission by or before December 31, 2018. Accordingly, Staff recommends that the Commission require Staff to present further recommendations for valuing and compensating DERs for consideration by the Commission before the end of 2018.

Staff would like to acknowledge and express its appreciation for the detailed work, contributions and deliberations of all participants, which greatly benefited the process and ultimate recommendations. The Staff proposal set forth herein was developed in large part based on the extensive input and active participation of numerous active parties in the collaborative process. Without the substantial commitment of the collaborating parties' time, effort, expertise, and insights, it would not have been possible for Staff to develop this proposal. While agreement on many important issues was not reached, the process was productive and informative, and the input of all active parties to this proceeding was invaluable.

2 Discussion, Recommendations, and Alternatives

2.1 Organization of Discussion

The following discussion presents Staff's recommended approach or alternatives regarding valuation and compensation of eligible generating facilities. It first presents several recommendations of general applicability, then details the elements of Staff's proposed valuation and compensation methodology, along with when and how that methodology should apply to various market segments, and finally describes the Market Transition Credit (MTC) that Staff proposes be available to certain projects. In the context of developing a Phase One VDER methodology, Staff identified distinctions among four major market segments:

- **On-site, mass-market projects and customers**
  For the purpose of this Report, mass market customers are defined as customers that are within a jurisdictional electric utility's residential or small commercial service class and that are not billed based on peak demand. On-site mass market projects are eligible generating facilities connected behind a mass market customer's meter.

- **Community distributed generation (CDG) projects and customers**
  CDG projects are defined as consisting of an eligible generating facility located behind a nonresidential host meter. CDG projects may include both mass market customers and large customers as subscribers. CDG projects are subject to further eligibility rules as described in the Commission's CDG Order.[21] The recommendations in this report take into account both the physical CDG projects and their customer members.

- **Remote net metering (RNM) projects and customers**
  RNM projects are cases where non-residential customers, as well as residential customers who own or operate farm operations, receive credits for excess generation by an eligible generating facility they own, lease, or operate at a site they own or lease and use those credits to offset the bill for meters at one or more other properties that they own or lease.

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[21] Case 15-E-0082, supra, CDG Order.

- **On-site large projects and customers**

  Large customers are defined as customers within a jurisdictional utility's non-residential demand-based or mandatory hourly pricing (MHP) service classifications. On-site large projects are eligible generating facilities connected behind a large customer's meter and not used to offset consumption at any other site.

In this Section, the currently applicable policy under Public Service Law (PSL) Sections 66-j and 66-l as implemented through Commission orders and utility tariffs is referred to as "NEM" or "NEM compensation," while Staff's proposed new compensation mechanism is referred to as the "Phase One tariff." Furthermore, the Commission's order acting on the recommendations within this Report and subsequent comments is referred to as the "Phase One Order."

2.2 DER Technologies Considered

Consistent with the direction provided by the Commission in the NEM Interim Ceilings Order, the collaborative focused on technologies and projects that are currently eligible for NEM. While those technologies are a diverse group, they share some basic similarities, including the ability to produce electricity for on-site usage and for export to the grid, limitations on size, and environmental attributes. In addition, the collaborative examined the potential of energy storage. While a variety of other DER technologies exist, further consideration is needed to determine whether and how the methodology developed in this report could be applied to compensate those technologies.

2.2.1 Technologies and Projects Included in Phase One

The recommendations in this Report apply to all projects and technologies that are eligible for net energy metering under current rules.[22] Those technologies can be divided into two categories, in recognition of their different characteristics:

- **Intermittent And Non-Dispatchable Technologies**

  This category consists of solar photovoltaic generation, wind generation, and micro-hydroelectric generation, where the operator has no ability to control when the facility

22 PSL §§ 66-j and 66-l.

generates electricity or at what percentage of its capacity it generates, other than by limiting it or taking it out of service, once it has been put into operation.

- **Dispatchable Technologies**

  This category consists of farm waste generation, fuel cell generation, and micro-combined heat and power (CHP) generation, where the operator has a meaningful ability to control when and at what percentage of its capacity the facility generates.

Consistent with PSL §§ 66-j and 66-l, eligible projects must have a rated capacity of 2 MW or less, except for CHP projects, which must have a rated capacity of 10 kW or less. Projects must also meet certain other eligibility rules under PSL §§ 66-j and 66-l, including fueling requirements for farm waste generation and compliance with relevant government and industry standards for construction and operation.

2.2.2 Energy Storage

Energy storage technologies, such as batteries, are not addressed in PSL §§ 66-j or 66-l. Staff recommends that storage be included in Phase One. Projects that pair any energy storage technology with an eligible generation facility, including for the purpose of exporting stored energy, will be permitted to receive compensation under the Phase One tariff. In addition, mass market and small wind systems that include storage will be permitted to retain NEM compensation. For CDG, RNM, and large on-site systems, the installation of storage will require participation in the Phase One tariff, rather than NEM. The presence of energy storage will not result in any change in compensation except that compensation for environmental value should only be provided for net monthly exports. While the use of system power to charge storage should be permitted, and even encouraged to the extent that it can support the system by reducing peak demand and variability, environmental compensation should not be provided for the export of stored system power.

Staff notes that NYSERDA is already examining support for solar-plus-storage on an expedited basis in anticipation of a program announcement in the early part of 2017. In addition, Consolidated Edison Company of New York (Con Edison) is pursuing a demonstration project that combines multiple solar plus storage systems linked together to improve grid resiliency and provide a dispatchable “virtual power plant” that Con Edison can control and rely on in real time. Con Edison is also pursuing grid-scale energy storage through a request for information seeking to demonstrate how large-scale utility storage can improve company operations, and establish how a singular type of energy storage can offer multiple kinds of value. Such interventions should seek to maximize system value derived from the integrated product where possible. Staff encourages NYSERDA and the utilities to examine an intervention and demonstration strategy that can help to further monetize system value, especially in high value locations of the distribution system, as successor tariffs are adopted.

Projects that include energy storage but no eligible generator are not included at this time but a methodology for their inclusion will be developed for implementation at or before Phase Two as further described below. The possibility of including such projects was discussed but Staff and other collaborative members, including representatives of the storage sector, agreed that separate consideration of the values of such projects would produce a better result.

2.2.3 Treatment of Existing Non-NEM Projects and Technologies

A number of existing tariffs and programs govern the treatment and compensation of projects that are not eligible for NEM.[23] Inclusion of those projects in VDER tariffs will require a thorough analysis of how a transition from those tariffs and programs can best be achieved. Due to the limited time available to develop Phase One, that analysis has not yet been performed. For that reason, those projects will not be eligible for the Phase One tariff. Categories of projects not included are:

- Projects larger than 2 MW;
- CHP projects larger than 10 kW;
- Projects involving generation using non-eligible fuel sources, such as natural gas and diesel, other than eligible fuel cells and eligible CHP generators; and
- Non-Generation DERs, such as demand response and energy efficiency.[24]

[23] For example, buy-back rates provide compensation for net injections and standby rates allow for the output of a generator, installed in-front of a customer's meter, to be netted against the usage of one or several buildings on the premises. In addition, the opportunity to earn compensation via a reliability credit under standby rates is now available.

[24] Customers that are otherwise eligible for participating in Phase One may, of course, also employ non-generation demand response and energy efficiency technologies without losing their eligibility.

Staff recommends ongoing work in the VDER proceeding to determine how best to transition those projects from current programs into a comprehensive VDER tariff. These recommendations are outlined in Section 2.11.

2.3 General Recommendations

This section details recommendations that apply generally to all classes of eligible projects. Some of these recommendations apply to both projects compensated under NEM and those compensated under Phase One tariff, while others apply only to projects compensated under the Phase One tariff.

2.3.1 Legacy Projects

Customers and developers with projects in service have made investments, entered into contracts, conducted financial planning, and organized business practices on the assumption that NEM compensation would continue to apply to their projects. While NEM compensation includes some variability, primarily through monthly changes in commodity prices and changes to delivery rates in rate cases, it is relatively stable and predictable. Applying the Phase One tariff to in-service projects would disturb those expectations and interfere with existing contracts.

Therefore, projects that are in-service at the time of the issuance of the Phase One Order will continue to receive compensation under existing NEM rules until 20 years after their in-service date, as described below.

2.3.2 Opt-In Availability

All projects that are entitled to continue to receive NEM based on the current policy may elect to opt-in for compensation under the Phase One methodology instead. Mass market customers and CDG projects that opt-in will be placed in the active tranche at the time of their opt-in for the purpose of calculating an MTC. This opt-in is irreversible and is only available before the implementation of a Phase Two methodology. Compensation under the Phase One tariff requires a utility meter capable of reporting net hourly exported generation. While utilities should make all reasonable efforts to install such meters for customers that wish to opt-in, customers without such a meter will continue to be compensated through NEM mechanisms until such a meter is installed.

2.3.3 Cost Allocation

As further described below, a significant portion of the compensation to projects under the Phase One tariff reflects direct, immediate or short-term utility savings. In order to avoid unnecessary reallocation of net revenue requirement across customer classes, recovery for that compensation should come from the same group of customers who benefit from the savings. For compensation that does not reflect a value that has been identified and calculated at this time, including the MTC, recovery should come from customers within the same service class as the beneficiaries to avoid revenue reallocation between service classes.

Those principles lead to the following recommendations:

- Compensation for energy and capacity values will be recovered from the same customers that benefit from reduced utility purchases of energy and capacity;
- Compensation for environmental values will be recovered from the same customers that benefit from reduced utility purchases of Tier 1 RECs;
- For demand reduction and locational system relief values, utilities should identify what portion of the value results from avoided lower voltage level costs and what portion results from avoided higher voltage level costs. The portion of compensation reflecting avoided lower voltage level costs will be recovered from all lower voltage level delivery customers. The portion of compensation reflecting avoided higher voltage level costs will be recovered from all delivery customers; and
- MTC compensation will be recovered from the service class of the project subscribers for CDG projects, with the total MTC for a project divided between service classes based on the percentage of the project serving subscribers from each class.

2.3.4 Limited Net Revenue Impact

Due to the imprecision of NEM discussed above, as well as the fact that more work is required to calculate all values provided by DERs, both NEM and Phase One tariffs are expected to result in net revenue impacts on utilities, which will be reflected in customer bills. While the existence of uncalculated and unascertainable values makes it impossible to determine the precise impact, it is possible to determine an upper bound for Phase One by calculating the remaining revenue impact after currently calculable benefits are netted out. To avoid the possibility of unreasonable impacts on non-participants during Phase One, the two portions of this proposal that may impose significant incremental net annual revenue impacts, the continuation of NEM for mass market customers and the offering of an MTC to certain projects, should be designed within a boundary of possible net revenue impact during Phase One.

Staff determined that a reasonable upper bound to use in developing this recommendation was a 2% incremental net annual revenue impact for all projects interconnected after the date of the Phase One Order. A 2% level reasonably balances the possible impact with the needs of the market while also taking into account the currently non-monetized benefits that these systems provide. It also ensures that there will be meaningful opportunities for customers in each utility service territory to install distributed generation or participate in a CDG project. The 2% will not result in a hard cap on MWs installed but instead, as described below, is used to design tranches of MTC for CDG projects, such that any CDG projects developed and interconnected after the final tranche is full in a particular utility service territory will impose no net revenue impact. Similarly, the MW trigger for mass market projects discussed below will prompt Commission consideration of appropriate action, as opposed to dictating a particular consequence.

2.3.5 Term

In order to determine whether a project should move forward, secure financing, and make and meet long term contractual commitments, customers and developers require certainty that a defined compensation methodology will apply to their project for a meaningful period. In the collaborative, a number of positions were expressed on how long this period should be; recommendations ranged from 15 years to life of system. In the RNM Transition Plan Order, the Commission grandfathered eligible projects for 25 years and allowed projects to petition for a longer period if pre-existing financing or other contractual agreements contemplated a longer period.[25]

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[25] Case 14-E-0151, Petition of Hudson Valley Clean Energy, Inc. for an Increase to the Net Metering Minimum Limitation at Central Hudson Gas & Electric Corporation, Order Granting Rehearing in Part, Establishing Transition Plan, and Making Other Findings (issued April 17, 2015) (RNM Transition Plan Order). One customer submitted such a petition and it was granted. Case 16-E-0007, Petition of Distributed Sun LLC, Building Energy Development US, LLC, and Cornell University to Extend the Monetary Crediting Period to 30 Years for Five Solar Photovoltaic Projects, Order Granting Modified Relief and Making Other Findings (issued April 27, 2016).

Staff recommends that projects retain the compensation methodology in effect at the time they are put into service for 20 years after their in-service date.[26] A twenty-year period is consistent with the term of contracts for Tier 1 RECs that NYSERDA will offer through auctions as part of the Clean Energy Standard (CES). A twenty-year period is also consistent with policy trends in other jurisdictions.[27] Developers or customers may file petitions requesting a longer term than 20 years if pre-existing financing or other contractual arrangements contemplated a longer period. After the twenty-year period ends, projects still in operation will be compensated based on the tariff then in effect.

2.3.6 Monetary Crediting Based on Locational and Temporal Values

Under a volumetric crediting system, the value to a customer of a kWh generated is based on that customer’s service class rather than on the value of that generation to the system. Volumetric crediting therefore cannot reflect locational values or temporal values but instead offers greater compensation to customers who are charged more on a per kWh basis. In order to implement a more granular and accurate compensation system, each individual kWh must be assigned an individual value based on when and where it is generated. This requires monetary crediting, where each kWh imported into the system is translated into a monetary amount based on the value it provides and that monetary amount is then used as compensation to reduce the customer’s bill.

2.3.7 Metering Requirements

In order to provide temporally granular compensation, a utility meter that can measure and record the net hourly import or export is needed. Many large projects, particularly RNM and CDG projects, are already equipped with such advanced metering. In order to be eligible for the Phase One tariff, all RNM, CDG, and large on-site projects must be equipped with metering with hourly recording capabilities. For RNM and CDG projects, this metering must be installed at the

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[26] Projects grandfathered under the RNM Transition Plan Order should continue to maintain their compensation mechanism for 25 years from their in-service date.

[27] See, e.g., California Public Utilities Commission Rulemaking No. 14-07-002, Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering, Decision Adopting Successor to Net Energy Metering Tariff (issued February 5, 2016).

time of interconnection. For large on-site projects, where an insufficient meter may already be present, the metering should be installed as soon as practicable.

2.3.8 Carryover of Credits

In any given month, a customer may create or a subscriber may receive more credits in compensation than the amount of their bill. In such cases, that amount will be carried over to the next month and applied as a credit on that bill. There will be no limit to the amount carried over by a customer or subscriber or the duration that a credit may be carried over, nor will carried over credits be paid out at any time.

2.3.9 Transfer of Ownership

For mass market, small wind, and large on-site projects, the project is closely tied to the underlying property and the customer as its owner or lessor. Modifying the compensation methodology when a property is sold may impair the value of that property. Furthermore, any transfer of such a property would involve the actual customer moving their residence or business location, and therefore no longer being able to take advantage of credits generated by the project. For that reason, the compensation methodology of a mass market, small wind, or large on-site project will be determined at the time it pays 25% of its interconnection costs, or at the time of the execution of a Standard Interconnection Contract if no such payment is required, and will not change during 20 year term based on changes in ownership or subscription.

For RNM projects, in some cases the project is on land where the customer also has a residence or business location. In other cases, the project may be on a site with no other use and the transfer of a project may not involve a customer moving their home or business. However, in either case, the value of the project is tied with the land once it is put into service. Furthermore, the payment of 25% of interconnection costs reflects a significant investment in the project. For that reason, the compensation methodology of an RNM project will be determined at the time of it pays 25% of its interconnection costs, or at the time of the execution of a Standard Interconnection Contract if no such payment is required, and will not change during 20 year term based on changes in ownership or subscription.

For CDG projects, subscribers may be added or removed regularly, both during the planning and development phases of a project and during the operation of the projects. Using different compensation methodologies for different subscribers would lead to significant complications for the utility and developer and confusion for the subscribers. Furthermore, changing compensation methodologies when there is a change in the owner or operator, where that owner or operator may be the anchor subscriber, the developer, or another entity, would unreasonably change the compensation for subscribers. Therefore, the compensation methodology of a CDG project will be determined at the time of it pays 25% of its interconnection costs, or at the time of the execution of a Standard Interconnection Contract if no such payment is required, and will not change during 20 year term based on changes in ownership or subscription.

2.3.10 DER Incentives

DER technologies eligible for the Phase One tariff may also be eligible for a number of other incentives, including incentives offered by NYSERDA and federal and state tax incentives. The receipt of any of these incentives will not impact their eligibility for or compensation under NEM or the Phase One tariff. These incentives were designed to meet a variety of policy goals and were instituted while NEM compensation was applicable to eligible generating facilities. The designers of those programs therefore clearly intended them to supplement, rather than replace, NEM. Inasmuch as the Phase One tariff will only offer greater compensation than NEM if the generation facility is providing greater value to the system than NEM recognized, any compensation above actual value provided by the Phase One tariff will be at most equal to, but often smaller than, any compensation above actual value inherent in NEM. For that reason, altering Phase One compensation based on the availability of other incentives would go against the intent of those incentives as a supplement to NEM.

2.3.11 Future Rate Changes

Customers that receive NEM have always been subject to changes in rates and in rate design, including increases and decreases in fixed customer charges, allocations between service classes, use of time-based or demand-based rates, and allocation of costs between various billing categories. Customers compensated under continuation of NEM or the Phase One tariff will similarly remain subject to such changes. For projects involving multiple sites, such as CDG and RNM projects, this applies to all sites and meters. Similarly, customers were not and should not be protected from changes in the price of fuel or electricity.

2.3.12 Subsequent DER Tariffs

Once subsequent DER compensation tariffs or mechanisms have been implemented, including through Phase Two of this proceeding, eligible projects receiving compensation under the NEM methodology or the Phase One tariff will be able to opt-in for compensation under the new tariffs or mechanisms. These opt-ins will be irreversible and will only be available while those tariffs are available to new projects.

2.4 Continuation of NEM for Projects in Service after the Date of the Order

As discussed above, all projects in-service as of the date of the Phase One Order will continue to be compensated based on the applicable NEM methodology. In addition, continued application of NEM compensation is appropriate for some other categories of projects.

2.4.1 Mass Market and Small Wind Projects

As described below in Section 2.6, Staff recommends that all mass market and small wind projects interconnected after the issuance of the Phase One Order and before January 1, 2020 receive NEM based on the current compensation methodology, subject to the MW trigger as discussed below.

2.4.2 Monetary Crediting Remote Net Metering Projects

The RNM Transition Plan Order created a process for the grandfathering of remote net metering projects into the monetary crediting compensation methodology for 25 years. As customers and developers made plans and investments based on this process, it would be unreasonable to create different rules for those projects now. Therefore, all projects that qualify based on that order will be grandfathered into monetary crediting remote net metering for 25 years, regardless of whether they are interconnected before or after the date of the Phase One Order.

2.4.3 Other Projects in Development

Staff recognizes that developers and customers plan projects and make significant investments long before those projects are put into service and that those activities are based on analyses focused on the current policy. However, if all projects for which development activities were initiated before the date of the Phase One Order, or even all projects for which preliminary interconnection applications were filed before the date of the Phase One Order, were permitted to elect crediting under NEM methodologies, potentially hundreds or even thousands of MWs of projects that have not advanced could move forward under the NEM methodology before the Phase One tariff comes into effect, effectively preventing the application of the Phase One methodology in some or all utility service areas.

Staff believes there should be an appropriate transition for the market that will enable a reasonable number of projects to proceed while market participants adapt to the Phase One methodology. Moreover, significant compensation changes should not be based solely on a metric, like in-service date, that is at least partially out of a developer's control. Accordingly, Staff recommends that a certain segment of projects put into service after the issuance of the Phase One Order be offered compensation through current NEM policy. This category of projects will be limited by both a deadline and by capacity. Projects will only be offered NEM compensation if they pay 25% of the interconnection costs, or execute a Standard Interconnection Contract if no such payment is required, as required by the interconnection queue management proposal and current Standardized Interconnection Requirements (SIR),[28] within ninety business days following the issuance of the Phase One Order. This will ensure that only projects that were far along in the development process prior the Order will be included. In addition, for CDG projects,[29] a limited capacity will be established for Tranche Zero, which will contain CDG projects interconnected after the issuance of the Phase One Order that receive NEM compensation. The proposed calculation of this capacity limit is described in Sections 3 and 4. To the extent that capacity in Tranche Zero remains unused after the ninety business day deadline has expired, that excess capacity will form Tranche One, as discussed further below.

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28 Case 16-E-0560, Joint Petition for Modifications to the New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 5 MW or Less Connected in Parallel with Utility Distribution Systems, Joint Petition (filed September 30, 2016).

29 No capacity limitation will be imposed on large on-site or volumetric RNM projects because the net revenue impact resulting from those projects is, depending on the utility, minimal or non-existent and because, under the Phase One tariff, such projects will receive no MTC so no tranches will be necessary.

2.5 Phase One Compensation Methodology - The Value Stack

2.5.1 Explanation of Approach

Staff proposes a Phase One VDER methodology that takes a significant first step in basing compensation on calculated value streams associated with eligible generation facilities. This first step includes values that were able to be considered and discerned with currently available data. Phase One reflects numerous months of successful work conducted by participants in the collaborative, and lays important foundation for continued investigation and deliberation in Phase Two. Staff anticipates that the overall impact of the Phase One VDER methodology will be significant, but at the same time will that it will also be bounded by structural design elements and by the limited duration of the Phase One methodology. A fully developed Phase Two methodology is expected to be presented for the Commission's consideration within two years, but further development is expected even before that, including through increased locational granularity in certain compensation streams, the development of portfolios that can serve as virtual generators, and the development of fully unbundled values by utilities, as described below.

The recommendations and proposal of alternatives are also informed by Staff's appreciation of the principal of gradualism, the existence of uncertainty in terms of what values exist and how they can be quantified, and the extent to which some values that may be limited by the current legacy utility system may be unlocked in the future by improved capabilities to plan for and make use of a modern, bidirectional electric system.

2.5.2 Structural Design

The Phase One VDER mechanism will compensate customers using a tariff based on calculations (and proxy calculations) of specific value sources and as applied to net exported generation from a DER host's account on an hourly basis. When considered together, these values comprise the "value stack" with each stated value serving as a component of the stack. Some of the VDER tariff's value stack components will be fixed for a given project, while some components will vary with fluctuations in energy markets. The following sections explain each value identified and the recommended compensation reflecting that value. Since utility DSIPs and BCA handbooks continue to receive public comment and are under Staff and Commission review, the approach used to determine values for the Phase One methodology is not dependent on methodologies presented in the DSIPs and BCA handbooks. The VDER tariff will result in monetary bill credits that are applied to a customer's or project subscriber's account in each billing cycle, with any excess credit carried over month-to-month, as described above.

In order to avoid disruption in New York's CDG market that could result from the Phase One methodology's limitations that preclude additional or more precise valuations, Staff recommends, as described further below, that the Phase One tariff also includes a market transition credit (MTC) that is stepped down over time for CDG. In addition, and as discussed above, Staff recommends consideration of an initial tranche that would provide limited opportunity for projects put into service after the date of the Phase One Order to receive compensation based on the current NEM methodology.

2.5.3 Energy Value

Staff recommends that both the value and the compensation for the energy that eligible generation facilities inject into the system, and the reduction in utility energy purchases resulting from that injection, take the form of actual day-ahead NYISO hourly LBMP energy prices at the time of generation. This compensation shall be calculated in the same way as charges for mandatory hourly pricing (MHP) customers are calculated and will therefore include avoided losses.[30]

Employing LMBP for energy compensation increases the temporal granularity of compensation and has the potential to increase location granularity. It also precisely reflects the costs that utilities are avoiding based on the injected generation. Furthermore, this method of compensation will recognize that some generation technologies, such as solar, may provide electricity at the most valuable time of the day.

2.5.4 Installed Capacity Value

The NYISO requires utilities to purchase capacity based on the MW usage on their system during the statewide peak hour of the previous year. Consequently, the actual installed

[30] To the extent that MHP kWh charges contain adders to collect costs in addition to LBMP and related losses, such as uplift and ancillary services, these adders should not be credited to net injections, as injections do not reduce these costs at this time. These are the types of costs that should be considered for further unbundling, as discussed below, and included in the discussions among DER companies, the utilities, and the NYISO, noted above.

capacity value that eligible generation facilities provide each year depends on their performance during the peak hour in the previous year. Dispatchable technologies, as well as intermittent technologies paired with storage, should be able to target performance during this peak period; while the hour itself is not known in advance, it will likely occur during an afternoon on a hot summer day.[31] Intermittent technologies not paired with storage, on the other hand, have no control of when they generate and, while solar generation in particular will generally be generating during summer peak hours, may miss the hour due to due to uncontrollable, purely random events, such as a poorly timed cloud.

The Phase One tariff could base compensation for installed capacity on this value by compensating eligible generation facilities each month with a lump sum equal to their MW performance during the peak hour in the previous year multiplied by the actual monthly generation capacity spot prices from NYISO's ICAP market that month. However, this would result in substantial variability for intermittent technologies, which could present issues for project financing. In recognition of this challenge, Staff presents the following compensation methodology for intermittent technologies.

Intermittent technologies will receive per kWh compensation based on the capacity portion of the utility's full service market supply charges. The capacity portion of the supply charge for the service class with a load profile most similar to a solar generation profile could be used for each kWh of generation all year. Alternately, that capacity portion could be assigned to specific summer hours to better reflect system needs. For that method, each June, the prior 12 months of Service Class 1 monthly capacity statements would be used to determine the $/kW per year. The $/kW/year amount would then be credited to the 460 peak summer hours: hours 14:00 through 18:00 each day in June, July and August. Compensation for the ICAP value would be calculated for kWh generation during those hours, and none during other hours. This would result in a similar potential capacity value as providing smaller compensation for each kWh generated all year but would encourage project siting and design focused on peak summer hours.

Dispatchable technologies, as well as intermittent technologies that opt-in, for example after installing storage, will be compensated each month with a lump sum equal to their MW performance during the peak hour in the previous year multiplied by the actual monthly

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31 Though it has occurred as late as September.

generation capacity spot prices from NYISO's ICAP market that month. In a project's first year, it would receive capacity compensation based on an average generation profile for a project of its technology and rated capacity in its service territory. To apply any other alternative to dispatchable technologies would not properly incentivize those technologies to perform during peak hours and would undercompensate those generators who do perform during those hours.

2.5.5 Environmental Value

Consistent with the BCA Order, Staff recommends that the Commission find that the environmental value of eligible behind the meter generation is at least equal to the Social Cost of Carbon (SCC) as calculated by the U.S. Environmental Protection Agency. However, the SCC may not reflect the full value of the environmental attributes of the generation. That value may be more fully reflected in the price of Tier 1 Renewable Energy Certificates (RECs) in New York's market. Furthermore, energy sources included in this proposal are eligible to produce Tier 1 RECs.[32] The CES includes a state goal for clean energy consumption that will be achieved by a combination of mandatory purchases by LSEs and voluntary actions.[33]

Starting in 2017, the CES will require the purchase of Tier 1 RECs by LSEs. The energy exported by eligible DER facilities can provide environmental value to LSEs by offsetting the LSE obligation to purchase Tier 1 RECs from NYSERDA or other large-scale generators. The value of that reduction will be equal to the cost of one REC per MWh, or one-thousandth of a

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32 There are two exceptions. CHP generators using non-renewable fuels are not eligible to produce Tier 1 RECs and therefore will not receive compensation for Environmental Value at this time. The eligibility of technologies to produce RECs will continue to be reviewed as part of the ongoing implementation of the CES. In addition, compensation for any environmental values provided by technologies that do not produce Tier 1 RECs will be part of Phase Two of this proceeding. Energy storage is not eligible to produce NYGATS Certificates. To compensate projects that combine storage with eligible generation for environmental values for kWh produced by that generation and exported to the grid but not for kWh imported from the grid, stored, and then exported back from the grid, those projects should receive environmental compensation based on their monthly net injections instead of all injections.

33 Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order Adopting a Clean Energy Standard (issued August 1, 2016) (CES Order).

REC per kWh. The cost of a Tier 1 REC will be based on NYSERDA's latest published Tier 1 REC sale price.[34] Because the purposes of the CES include capturing the benefits of carbon reduction, the Tier 1 REC value should be considered as a substitute for, rather than an addition to, the Social Cost of Carbon.

As is the case with other elements of value provided by DERs, the environmental value cannot be fully ascertained at this point in time. While Staff anticipates that the Tier 1 REC price will remain higher than the SCC, it is possible that NYSERDA's latest published sale price of a Tier 1 REC may fall below that amount. Therefore Staff recommends that the Phase One tariff include environmental compensation as the higher of the applicable Tier 1 REC price per kWh generated or the SCC per kWh value, as calculated by Staff consistent with the BCA Order. Because the NYSERDA CES auctions will procure Tier 1 RECs for a 20-year period at a fixed price and to offer greater stability to developers and customers, the environmental value per kWh for a given project will be fixed for a twenty-year period based on the higher of the Tier 1 REC price most recently published by NYSERDA at the time of interconnection or the SCC per kWh value as most recently calculated by Staff at the time of interconnection.

Because the customer-generator or CDG member is being compensated for the environmental value the DER provides, and is in fact being compensated based on the value of Tier 1 RECs, compensation under the Phase One tariff precludes any DER generator from participating in the CES Tier 1 auctions administered by NYSERDA and the separate sale of Tier 1 RECs for CES compliance or other purposes. Exported generation compensated through the Phase 1 tariff will be tracked in the New York Generation Attribute Tracking System (NYGATS) to support attainment of the CES obligation by the interconnecting LSE by enabling a reduction of the obligation of that LSE. Alternatively, in the event the certificates tracked in NYGATS are claimed for the purpose of environmental and sustainability certifications, the exported generation can be recognized as contributing to the state's overall CES goal but not the CES Tier 1 obligation.

Non-exported behind-the-meter generation will reduce LSE compliance obligations in the same manner as energy efficiency and therefore does not create a Tier 1 REC for separate sale.

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34 NYSERDA expects to publish the quantity and price of Tier 1 RECs for 2017 LSE compliance on or about November 1, 2016.

Certificates associated with such on-site generation will be tracked in the NYGATS. Similar to the case of exported energy, NYGATS certificates associated with energy consumed on-site can be retired for the purpose of environmental and sustainability certifications. Whether or not retired for voluntary claim, the NYGATS certificates associated with non-exported behind-the-meter generation can be recognized as contributing to the state's overall CES goal but not the CES Tier 1 obligation.

2.5.6 Demand Reduction Value and Locational System Relief Value

All parties agree that DERs can reduce delivery costs, but recognize that we are at the beginning stage of calculating that value. The Value of DER process has not produced a valuation methodology that identifies and includes all potential distribution system values and this is an area where significant evolution is expected during Phase Two. Many distribution system values may already exist but data for accurate calculation is not yet available. Other value streams, such as the benefits of local reactive power or the valuation of quick local response, are not modeled in either the wholesale or retail markets. As further discussed below, the MTC is in part based on recognition that these values exist but cannot be calculated at this time. For that reason, for projects that receive an MTC, no additional separate compensation based on distribution value will be provided, except for Locational System Relief as discussed below.

However, for projects that do not receive an MTC, some additional compensation must be provided. Sufficient information does exist to offer one piece of the value provided to the distribution system by these projects, the Demand Reduction Value. As part of developing Demand Response tariffs as required in the Dynamic Load Management proceeding, the electric utilities have filed Marginal Cost of Service (MCOS) studies and used those studies to calculate the value to the distribution system of reducing demand during distribution peaks. Currently, compensation for providing this value is available to demand response resources. However, participation in those demand response programs is difficult or impossible for most projects that will be compensated under the Phase One tariff, either because the resource is intermittent and therefore cannot respond to calls in the same way as the dispatchable demand response assumed by the programs or because the resource is in operation most of the time and therefore acts as "baseload" rather than "response." While efforts are underway to improve these programs and broaden opportunities for participation, it is appropriate to include compensation for the Demand

Reduction Value that distributed generators create, as calculated for these programs, in the Phase One tariffs.

In recognition of the different character of these technologies, a separate method for determining compensation is proposed. The MCOS study $ per kW-year values used for Demand Response tariffs should be "deaveraged" to enable the calculation of two values for delivery cost savings from demand reduction: the Demand Reduction Value that applies across the service territory and an additional "Locational System Relief Value" that applies to high value areas for a limited number of MWs. The resulting $ per kW year will be distributed across the ten highest usage hours in a utility's territory and generators will be compensated based on their performance during those hours. As discussed further below, to the extent possible the values found in the MCOS study will be disaggregated to offer more granular locational compensation; furthermore, where that is done, the ten hours chosen will be based on local peak to the extent possible and appropriate. This compensation will take the form of a monthly lump sum based on the project's kW performance during those ten hours in the previous year. In a project's first year, it will receive Demand Reduction Value compensation based on an average generation profile for a project of its technology and rated capacity in its service territory.

Furthermore, to recognize Locational System Relief values, the utilities will be required to identify high-value locations, as well as any limitation in the number of MW that are required in those locations. A dollar per kW-year compensation should be identified for those areas to reflect the higher value. This compensation should represent the value provided in these locations in excess of the Demand Reduction Value, and will therefore be credited to eligible facilities that locate in those areas and are within the required number of MW as additional compensation on top of the MTC or Demand Reduction Value compensation. The higher dollar per kW value identified by the utility would be locked in for the first ten years for those high-value locations. For all other areas, the dollar per kW value would be subject to modification based on updates to MCOS studies, increased locational granularity, and deaveraging to reflect the separation of the high-value areas.

As with capacity compensation based on performance during the peak hour, this compensation mechanism results in uncontrollable quantity variability for intermittent technologies not paired with storage, though the use of ten hours, rather than one, offers some mitigation. In order to provide greater compensation stability and further reduce risk, the utilities should develop a fee-based portfolio service under which DERs are aggregated into a virtual generation resource with an average nameplate capacity based on the overall capacity and types of resources in the portfolio. The utility would then manage the portfolio to maximize system value and compensate the participants based on that value.

2.5.7 Potential Values Not Included

Several potential values were discussed during the collaborative process but are not included in this proposal. These values include: distribution system values not reflected by the locational demand reduction value, as discussed above; reduced SO_2 and NO_x emissions, to the extent that their damage costs are not already embedded in the LBMP through existing programs; non-energy benefits, including reductions in CO_2 emissions for reasons other than reduced electric generation, land and water impacts; environmental justice impacts, including reduced local emissions; and wholesale price suppression. In addition, this proposal does not address the ability of customers with behind-the-meter generation to avoid contributing towards societal benefits embedded in utility rates or otherwise recovered through kWh charges, such as low-income discounts.

Some of the values not included, including currently uncalculated distribution system values and reduced SO_2 and NO_x emissions, will be considered through the Phase Two process. Others, such as non-energy benefits, are not properly addressed through a Value of DER tariff for the reasons noted in the BCA Framework Order.

Finally, for some, no compensation should be offered. In particular, as recognized in the BCA Framework Order, wholesale price suppression is simply a transfer payment, not a resource or societal benefit. When it does occur, it is appropriately recognized as a mitigator of bill impacts, but likely to be an ephemeral one, evident only until the supply side of the market adjusts and prices fall back to sustainable levels. In fact, in this case, New York State's goals under NY-SUN, the State Energy Plan, and the Clean Energy Standard have been broadcast so publicly, and so far in advance of the resource impact, the supply side of the market's planning has already been affected, and will clearly have completely adjusted to the effects of these resources by the time they are an place. Thus, there is not be any market price suppression from adding these clean resources—they will simply replace the fossil-based resources that, otherwise, would have been provided in the market in the future.

2.5.8 Market Transition Credit

Some projects are likely to receive equal or greater compensation under the Phase One tariff as compared to what they would receive under current NEM mechanisms. For example, many volumetric remote net metering projects would serve primarily to offset commodity costs at usage sites, and therefore a Phase One tariff that continues to compensate them for commodity cost while also compensating them for environmental value and locational demand reduction value should be an improvement. Dispatchable technologies will also have the opportunity to receive increased compensation through performance during peak hours, with respect to both installed capacity compensation and locational demand reduction compensation. For such projects, while Staff recognizes that the value stack is imprecise, Staff recommends that their compensation be set at the value stack for Phase One, while a collaborative immediately embarks upon Phase Two to improve the accuracy of that compensation.

However, other projects are likely to receive lower compensation under the Phase One tariff as compared to what they would receive under current NEM mechanisms. The projects for which that is most clear are solar CDG projects without storage, which would receive volumetric crediting for under NEM mechanisms. For those projects, moving immediately to the value stack could result in market disturbances. Furthermore, as recognized above, the value stack is imprecise in terms of total value provided by generators, and in particular does not reflect full identification of distribution system values. For those reasons, it is appropriate to provide an additional market transition credit to such projects, bounded based on utility net revenue impact and divided into tranches. The calculation of the MTC is further discussed below.

While storage paired with generation offers an intermittent technology the opportunity to provide increased value and therefore receive increased compensation in a similar way to dispatchable generation, the inclusion or installation of storage in an otherwise eligible project will not render that project ineligible to receive the MTC. This avoids creating a disincentive to installing storage, which offers the potential of significant benefits to the system and to the customer. However, the MTC, like compensation for environmental values, will only be provided for net monthly injections of projects that include storage, to avoid permitting uneconomic arbitrage.

2.6 On-Site Mass Market Projects and Small Wind

2.6.1 Definition and Background

For the purpose of this Report, mass market customers are defined as customers that are within a jurisdictional electric utility's residential or small commercial service class and that are not billed based on peak demand. On-site mass market projects are eligible generating facilities connected behind a mass market customer's meter.

2.6.2 Recommendations

On-site mass market projects put into service after the issuance of the Phase One Order will continue to receive NEM based on the current compensation methodology. That is, their kWh usage and generation is netted each billing cycle; if their usage exceeds generation, they pay only for the excess usage; and if their generation exceeds their usage, their excess generation becomes kWh credits that offset their usage in the next billing cycle.

Projects put into service after January 1, 2020 will receive compensation based on the mechanisms developed in Phase Two. Should a new compensation methodology not be in place by January 1, 2020, projects put into service after that date will receive NEM compensation only until the new compensation methodology is developed and implemented and shall then be transferred to the new compensation methodology.

In addition, for each service territory, a MW trigger has been proposed. The MW trigger has been calculated, as further described in Sections 3 and 4 below, to sustain activity based on levels and approximate growth trends from 2014-2016. The rated capacity of all eligible mass market generation interconnected after the date of the Phase One Order will be counted towards this MW trigger, with the exception of small wind. If growth in mass market installations results in this MW trigger being reached prior to the implementation of a new compensation methodology, the Commission will determine what action is appropriate under all the facts and circumstance then applicable. The reaching of the MW trigger will not have any effect on projects put into service prior to that Commission action.

To enable timely awareness of the potential for reaching the MW trigger, utilities will be required to provide monthly public reports on the number and capacity of mass market projects. Furthermore, the utilities should provide public notice, including notice to Staff, when mass market installations reach 85% of the MW trigger and when the trigger is reached. In addition, the utilities should expeditiously develop unbundled values, as described below, such that before the MW trigger is reached they can propose new compensation methodologies for consideration.

Continuation of net metering for mass market customers is appropriate because the maturation of the segment and business models requires notice and a more gradual evolution to a new compensation methodology. In addition, the Phase One tariff will require specific metering, and so applying this stipulation to all mass market customer-generators could disrupt AMI schedules. The increased complexity with Phase One compensation methodology would also pose particular problems in this sector. Transition of this sector onto a new compensation methodology will be a component of the Phase Two deliberations.

Staff and the collaborative also considered whether other requirements should be imposed on this sector, such as the installation of smart inverters or mandatory participation in Time of Use Rates. Discussion of smart inverters reflects consideration of how best to address the growth of the installed base of on-site systems compensated through NEM and of how the value to the system can be maximized. However, further questions remain regarding smart inverters. The Commission should require that Staff, in consolation with interested parties, present a report and recommendations regarding this topic by July 1, 2017. Topics to be addressed include but are not limited to the definition of a smart inverter including operating parameters and the circumstances under which any requirement should be imposed. Comments are invited regarding other topics to be included in the scope of the report. With regard to mandatory participation in Time of Use Rates, it was recognized that there are upcoming utility filing regarding development and implementation of Time of Use rates. The application of these rates will be considered during review of utility Time of Use filings.

2.7 Community Distributed Generation Projects

2.7.1 Definition and Background

CDG projects are defined as consisting of an eligible generating facility located behind a nonresidential host meter. CDG projects may include both mass market customers and large customers as subscribers. CDG projects are subject to further eligibility rules as described in the Commission's CDG Order.[35] It's expected that most CDG projects will export 100% of their

[35] Case 15-E-0082, supra, CDG Order.

generation to the grid to earn credits to provide to subscribers, but some may be behind the meter of a member and include some on-site usage.

The CDG market in New York State is nascent, with CDG authorized by the Commission only one year ago and with many projects in the interconnection queue but very few close to operation or commencing construction. Staff is cognizant of the need to avoid cliffs or uncertainty that could harm this market's development.

2.7.2 Recommendations

CDG projects put into service after the issuance of the Phase One Order and not eligible for continuation of NEM will receive compensation based on the Phase One tariff. These projects are either behind new meters and export 100% of their generation to the grid, like RNM projects, or are behind the meter of a large customer, like On-Site Large projects. In addition, these projects will be managed by CDG developers, anchor members or subscriber organizations that have the capability to manage a more nuanced compensation mechanism.

2.8 Remote Net Metering Projects

2.8.1 Definition and Background

Non-residential electric customers, as well as residential customers owning farm operations, may designate net metering credits created by an eligible generator at one property they own or lease to the meters of other properties they own or lease. This process is commonly referred to as remote net metering.

Prior to the RNM Volumetric Crediting Order,[36] the value of credits was calculated by converting the kilowatt-hours (kWh) of excess generation at the host site to monetary credits based on the per kWh charges applicable to the Host Account, which depend on its location and service class. The bill for the Satellite Account was then reduced by that monetary amount. In many cases, the per kWh charges at the Host Account are significantly larger than at the Satellite Account because the Host Account is in a non-demand-metered service class while the Satellite Account is in a demand-metered service class.

[36] Case 14-E-0151, supra, Order Raising Net Metering Minimum Caps, Requiring Tariff Revisions, Making Other Findings, and Establishing Further Procedures (December 15, 2014) (RNM Volumetric Crediting Order).

In order to avoid uneconomic arbitrage and unreasonable promotion of remote net metering over on-site net metering, the Commission modified the method of calculating the credit value in the RNM Volumetric Crediting Order. Under the volumetric crediting system adopted in the RNM Volumetric Crediting Order, the excess kWh generated at the host site are transferred to the Satellite Account as volumetric credits, which then offset the Satellite Account's kWh charges thereby reducing their bill.

However, volumetric crediting results in very low credit value for many customers because a large portion of their bill is a demand charge, which volumetric crediting does not reduce. Implementation of the Phase One tariff therefore offers the opportunity to increase compensation for those customers to a more accurate value without causing net utility revenue impact.

2.8.2 Recommendations

RNM projects put into service after the issuance of the Phase One Order and not eligible for continuation of NEM will receive compensation based on the Phase One tariff. These types of projects, which involve large, sophisticated businesses as customers, are well-suited for a more accurate, and therefore more complex, compensation system. The Phase 1 Tariff may reenergize this segment, which has found it difficult to development new projects under volumetric crediting.

2.9 On-Site Large Projects

2.9.1 Definition and Background

Large customers are defined as customers within a jurisdictional utility's non-residential demand-based or mandatory hourly pricing (MHP) service classifications. On-site large projects are eligible generating facilities connected behind a large customer's meter and not used to offset consumption at any other site.

2.9.2 Recommendations

On-site large projects put into service after the issuance of the Phase One Order and not eligible for continuation of NEM will receive compensation based on the Phase One tariff for their net hourly exported generation. Generation consumed on-site will not be metered by the utility and will, as it currently does, directly reduce metered usage and therefore bills rather than resulting in compensation. To the extent that an eligible generating facility that would be subject to the Phase One tariff is interconnected on a site without a meter capable of providing data on net hourly imports and exports, that project will be provided with compensation based on NEM methodology until such a meter is installed. These types of projects, which involve large, sophisticated businesses as customers, are well-suited for a more accurate, and therefore more complex, compensation system.

To the extent that a customer who has built or builds a project on-site prefers to receive compensation based on the Phase One tariff mechanisms for all generation, rather than consuming some generation on-site, that customer may arrange for that project to be separately interconnected and metered, such that no generation it produces is consumed on-site but instead all generation is exported to the grid. In that case, as with an RNM project, the customer will receive compensation for all generation based on the value stack.

2.10 Market Transition Credit and Tranches

2.10.1 Eligibility for the Market Transition Credit

CDG solar projects that are included in the Phase One are eligible to receive an MTC, intended to make their estimated compensation equal to NEM in a first tranche (Tranche 1), 10% less than NEM in a second tranche (Tranche 2), and 20% less than NEM in a third and final tranche (Tranche 3). The MTC will be applied to 80% of the generation of eligible CDG projects. The MTC will not be applied to 100% of the generation because the MTC is based on comparing the value stack to the retail rate for residential customers, while up to 40% of the generation may be assigned to large non-residential subscribers, who may pay a substantially lower per kWh rate. Other options for addressing this include:

a. Compensating MTC for 100% anyway;
b. Compensating MTC for 60%, given that projects may include as little as 60% of generation dedicated to residential and small commercial customers; or
c. Compensating MTC based on a project’s actual customer class makeup.

Option A would result in an imbalance of compensation for projects with one or more large non-residential subscribers, while Option B would result in an imbalance of compensation for projects with all residential subscribers. Option C would arguably result in the most appropriate compensation, but could prove too strong a deterrent to including large non-residential subscribers in projects, and would add significant complications for utility billing systems as well as for project developers. Compensating at 80% reasonably limits any imbalance in compensation while also providing greater certainty and simplicity in Phase One.

2.10.2 Calculation of the Market Transition Credit and Tranches

The MTCs for each tranche should be calculated by each utility and set one time following the issuance of Commission's Phase One Order. An initial tranche, Tranche Zero, will not require an MTC calculation because projects in Tranche Zero will receive NEM compensation, as described above. If capacity remains in Tranche Zero after the end of the ninety business day eligibility period, remaining capacity will roll over into Tranche One. The MTC for Tranche One will be calculated by subtracting the estimated value stack from the current total residential retail rate. However, Tranche One will consist only of capacity rolled over if Tranche Zero is not filled; if Tranche Zero is filled, Tranche Two will follow it. Appendix A offers a proposed methodology for calculating the residential retail rate and estimating the value stack in order to calculate the MTC.

No number representing the Demand Reduction Value will be included in the value stack for the purposes of this calculation because the MTC is intended to subsume the values the Demand Reduction Value (DRV) represents. In general, the MTC will exceed the compensation for DRV that an intermittent project would earn in an average year. However, in some cases the compensation received from the MTC over the course of the year may be lower than what a project could theoretically have received if it had been compensated based on the DRV methodology. The use of a fixed kWh MTC rather than a peak-performance-based Demand Reduction Value to compensate certain projects is intended to, among other purposes, respond to developer concerns that application of the DRV methodology would create too much risk and uncertainty because a given year's peak coincident performance is based on factors outside of a developer or customer's control. By providing the MTC to certain projects, both the risk of low compensation and the chance for high compensation are eliminated. However, if a project that would be eligible for an MTC wishes to accept the uncertainty of the Demand Reduction Value in exchange for the chance of higher compensation, it may opt out of the MTC and be compensated based on the value stack, including the Demand Reduction Value. This opt-out will be irreversible.

The MTC for Tranche 2 will be calculated by subtracting the estimated value stack from 90% of the residential retail rate. The MTC for Tranche 3 will be calculated by subtracting the estimated value stack from 80% of the residential retail rate.

In some utility territories, MTC calculations under particular tranches may result in a negative number or zero; for those utility territories, if the MTC calculation for a given tranche results in a negative number or zero, there will be no such tranche, and instead prior tranches will be larger. After the final tranche is filled, projects will be compensated based on the value stack associated with the Phase One methodology, including the Demand Reduction Value, and the MTC would no longer apply.

2.11 Next Steps

2.11.1 Filing of Additional Information for Final Calculation of MTC and Tranches and Identification of Locational System Relief Values

The electric utilities should be required to, as soon as reasonably achievable following the Phase One Order, file any additional information necessary for calculating the MTC and tranches, including information on their load shapes. In addition, they should be required to identify areas where a Locational System Relief Value will apply and identify the compensation for those areas and the number of MW that can receive that compensation, as well as providing deaveraged Demand Reduction Values.

2.11.2 Utility Development of Virtual Generation Portfolios and Unbundling of Values

As the entities responsible in the first instance for charging just and reasonable rates and prudently developing the electric system, the utilities have the obligation of designing tariffs and programs that maximize the value of DER to the system and that fairly compensate DERs for creating that value. Consistent with the principles of REV, the utilities should also receive appropriate compensation for the services they provide. For those reasons, the Commission should require the utilities to begin developing fee-based, virtual generation portfolios through which they work with DER providers so that DERs are installed and operated in a way that best supports the overall system.[37] These portfolios will allow better recognition of the fact that DERs impact the system not solely as individual projects but also as part of an ecosystem that influences system planning, operation, and development.

Furthermore, in order to support further development of VDER tariffs, utilities should be required to begin developing tariffs that more fully unbundle the values and services currently

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[37] As described above, Consolidated Edison has already started a virtual generation program as a demonstration project.

embedded in average bundled rates. The increased granularity offered in these unbundled tariffs will facilitate accurate compensation of DER providers. Staff seeks comment on what values can be unbundled in the next 12 months and what values will require the addition of certain functionalities proposed in utility DSIP filings and the associated timing of unbundling those values.

2.11.3 Unrelated CDG Petitions

This Report focuses on the compensation methodology for DERs and with issues directly related to that methodology. Several unrelated issues regarding CDG rules have been raised in petitions filed by stakeholders.[38] Those issues have not been sufficiently developed for Staff to have a recommendation at this time. This report recommends that those petitions be resolved separately in the CDG proceeding.

2.11.4 Approaches for Additional Non-NEM Eligible Projects and Technologies

As discussed above, further work is needed to transition non-NEM eligible projects and technologies, which are currently addressed by other programs and tariffs, to a comprehensive VDER tariff. The process for continued development of this area should include:

i. For energy storage systems not co-located with NEM-eligible generation, development of a proposal by early 2017 to enable Commission action in 2017.
ii. For CHP larger than statutory maximum but smaller than 2 MW, development of a proposal as part of Phase Two or earlier.
iii. For non-NEM-eligible generation and for projects larger than 2 MW, development of a proposal as part of Phase Two or earlier.

2.11.5 Process for Development of Phase Two Tariffs

Staff will immediately embark on initiating a process leading to the development of Phase Two tariffs, to be considered by the Commission by the end of 2018. To that end Staff intends to convene the members of the collaborative in November 2016 to solicit feedback as to how this collaborative work including the topics for consideration should proceed.

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38 Case 15-E-0082, supra, SolarCity Petition on CDG Credit Payments (filed October 21, 2016); Joint Request for Waiver (filed September 1, 2016).

3 Evaluation of Phase One Impacts and Design

3.1 Background and Context

In developing recommendations for Phase One, Staff undertook analysis of the values provided to and impacts on the recovery of utility revenue requirements associated with deployment of DERs under existing retail rates and Phase One methodology. In approaching this analysis, Staff recognized that the ongoing transition towards more precise identification and quantification of value as part of REV places certain limitations upon this analysis, but deems that the values and impacts on which it has conducted its analysis are sufficient for gauging the degree of impact for a Phase One decision.

It is first important to define what is meant by “values and revenue impacts” for the purpose of this analysis. The “values” refer to Staff’s current best estimate of the ascertainable categories of benefits that distributed resources—and in particular solar PV because that technology will comprise the vast majority of projects—provide to the system and society. These categories were discussed in Section 2.5: avoided LBMP; avoided system capacity (ICAP); avoided delivery system costs; and avoided environmental costs associated with Tier 1 REC obligations.[39] With respect to “revenue impacts,” the analysis estimated the incremental amount of revenue requirement embedded in existing rates that must be collected from all customers resulting from the adoption of DER technologies under NEM or Phase One methodology. Due to the highly speculative nature of predicting future rate levels and rate design changes, Staff adopted a simplified approach that uses a snapshot of existing tariff levels and structures, and customer class revenues.

3.2 Framing for Analysis

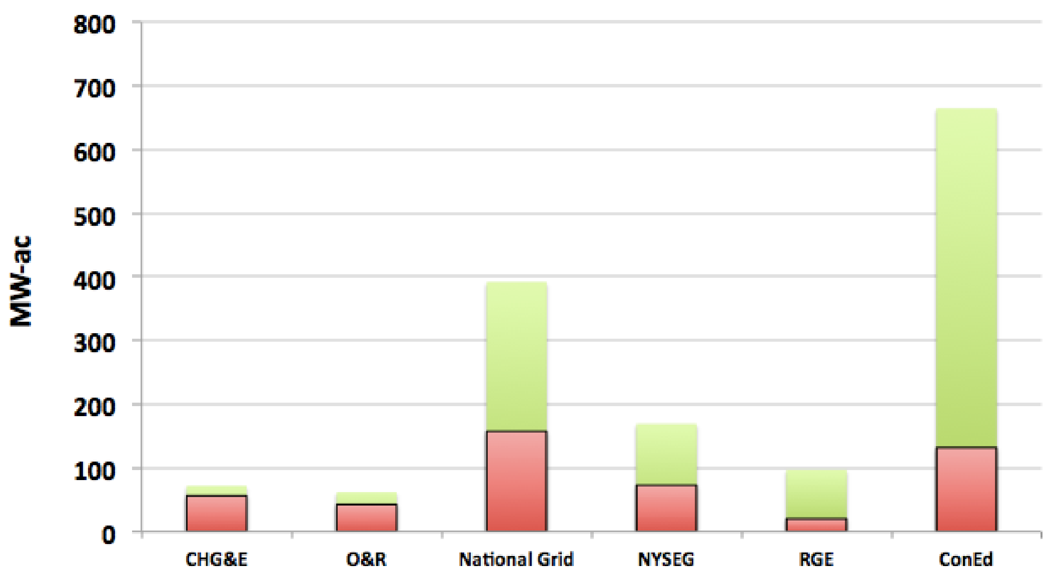
The analysis focused upon several DER deployment scenarios resulting from adoption and implementation of decisions under Phase One. While Phase One will have meaningful influence and make positive steps towards more precise value of DER, the impacts are ultimately bounded by the anticipated two-year period for which projects would be developed under Phase One before transitioning into subsequent phases. To measure the balance between market

[39] All values were “grossed up,” when appropriate, to include the identifiable values, such as losses, that distributed resources provide over bulk resources.

opportunity and revenue impact during Phase One, the analysis is premised upon an incremental 2% annual net revenue impact for each utility's residential and commercial customer class, inclusive of bundled and delivery-only customers. The selection of an incremental 2% annual impact was based upon the need to select an upper boundary for Phase One while also establishing room for market growth in all utility service territories. While all DER projects developed under Phase One would contribute to value and utility net revenue impacts, the analysis focused upon technologies and project types that represent the vast majority of current market potential, which is primarily solar projects and CDG projects.

The development of customer-sited NEM, particularly solar PV, has seen robust growth throughout the state over the past several years. Using the methods described under Section 3.3, Figure 2 presents the penetration of NEM for technologies eligible under Public Service Law §66j as of August 31, 2016 and compares against the former NEM cap of 6% of 2005 utility peak demand.

Figure 2 – Current NEM Penetration Compared to Former NEM Caps



	CHG&E	O&R	National Grid	NYSEG	RGE	ConEd
6% 2005 peak demand	72	62	392	170	98	665
Installed NEM through 8/31/16	57	43	158	73	20	132

Additionally, subsequent to the Commission's adoption of a CDG program on July 17, 2015 and tariff filing by the utilities on October 23, 2015, interconnection applications to the utilities surged dramatically as depicted by Figure 3. Between October 23, 2015 and April 30, 2016, for instance, interconnection queues increased from roughly 984 MW to more than 3,500 MW, the majority of which came in as CDG applications.

Figure 3 – Growth of Net Metering Queues June 2015 through August 2016

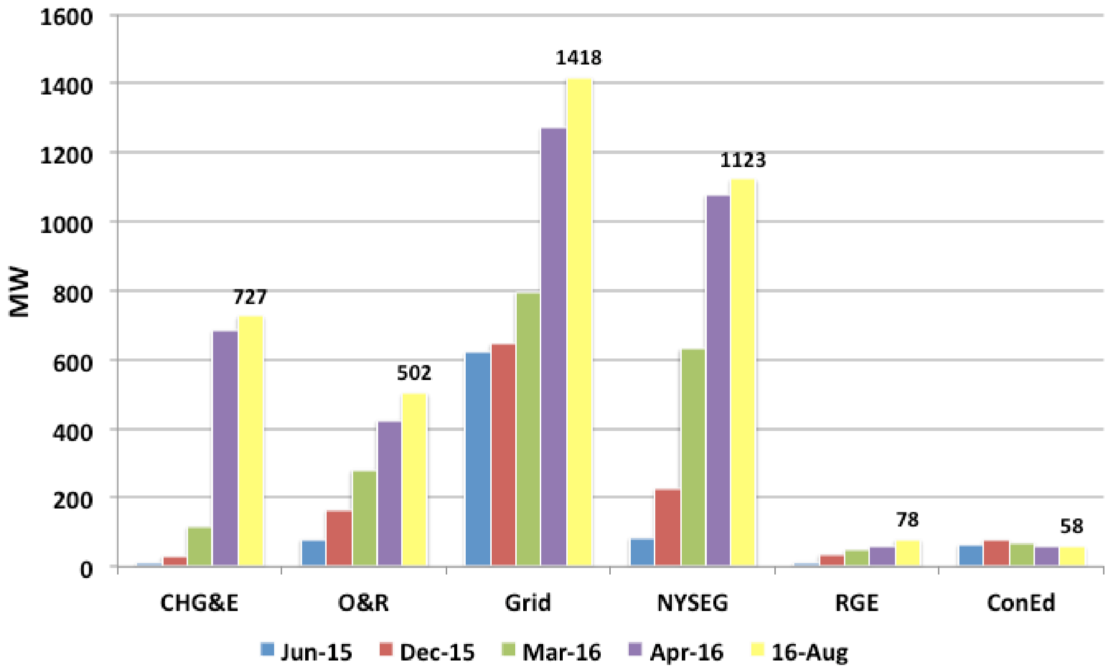
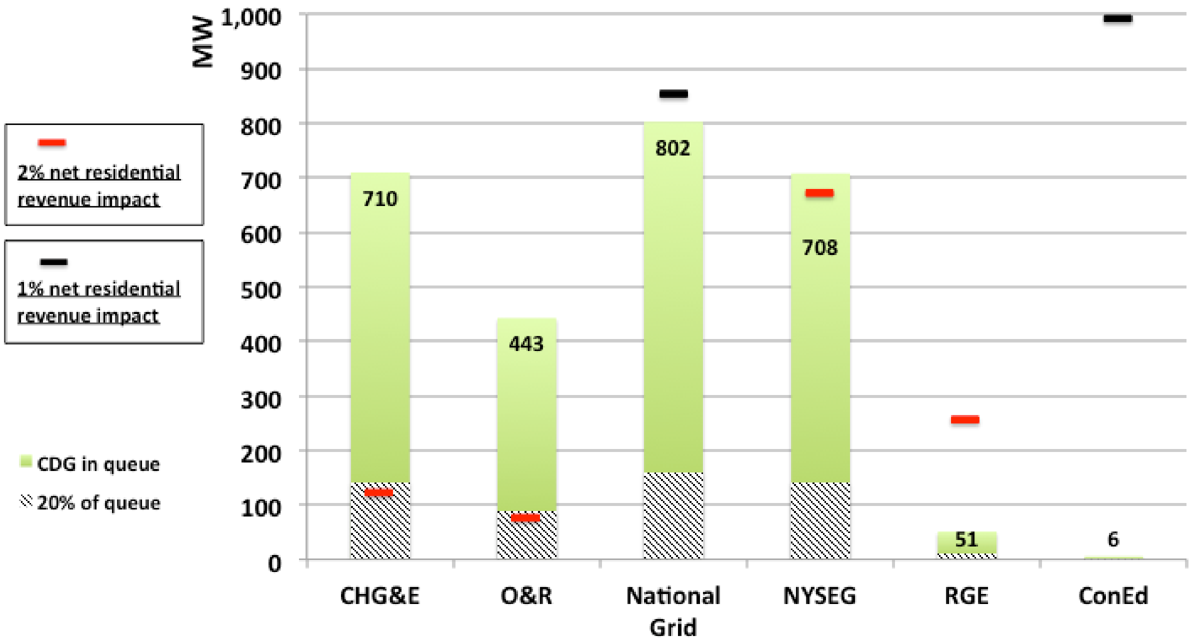


Figure 4 presents CDG projects in the utility interconnection queues as of August 31, 2016 and also compares against the net utility revenue impact for the residential class using the methods described under Section 3.3. For illustrative purposes, Figure 4 also presents 20% of respective CDG queues, based upon a general inference and estimation that only of portion of the CDG queues represent viable projects.

Figure 4 – CDG projects in Utility Interconnection Queues Compared to Net Annual Utility Revenue Impact



3.3 Methods and Approach

Using the incremental 2% net revenue impact, the analysis relied upon various inputs and assumptions in conjunction with Phase One methodology to analyze utility-specific impacts associated with selected market segments and project arrangements. Populations of projects that were analyzed include the following:

1. Two years of estimated residential growth of solar PV under continuation of NEM;
2. Two years of estimated small commercial growth of solar PV under continuation of NEM;
3. CDG projects under continuation of NEM;
4. CDG projects receiving MTC under VDER Phase One methodology; and
5. Monetary remote net metering projects under NEM.

As mentioned, these explicit populations of projects were selected recognizing that these technologies and project types represent the vast majority of current market potential, and therefore the largest potential impact on net utility revenue.

3.3.1 Continuation of NEM for Mass Market Residential and Commercial Projects

Assuming a continuation of recent annual growth rates, the analysis calculated the incremental net annual utility revenue impact associated with continuing NEM for residential and small commercial customers over a two-year period in each utility service territory. The analysis assumed that residential projects are less than 25 kW in size and that small commercial projects are less than 200 kW in size.

For mass market projects under continuation of NEM, the analysis assumed that gross utility revenue impact is associated with a NEM customer's avoidance of its kWh delivery charge, systems benefit charge, and MFC. It is then assumed that these revenue impacts are offset, in part, by the environmental and distribution values provided by these systems, resulting in net utility revenue impacts.[40] As a base case for analyzing mass market systems, the approach applied net utility revenue impact to a system's approximate percentage of generation that is exported to the grid on an hourly basis. The approximation used for residential systems is 50%, and 30% for small commercial systems.

This is not to say that there is no net utility revenue impact associated with the portion of NEM generation that lowers instantaneous on-site load. However, consistent with the recommendations above, instantaneous on-site consumption of generation is treated as load modification similar to energy efficiency, or other methods of instantaneous load reduction. What makes NEM treatment distinct from other forms of behind-the-meter load reduction is that electricity that is actually exported to the grid is treated as if it were an instantaneous, behind-the-meter load reduction. Thus, the incremental revenue impact that is attributed to continuing NEM, here, is that associated with the generation that is exported to the grid and eligible to receive a full retail rate credit under NEM. While the analysis focused its mass market analysis on this hourly exported generation, Staff has also conducted a sensitivity that applies net utility revenue impact to 100% of system generation. A simple inference, based upon the assumed proportion of hourly exports, is that in the case of residential customers, the net impact would be doubled, and in the case of small commercial customers, net impact would be more than tripled.

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40 As discussed in this report, Staff appreciates that there may likely be other values that may not be quantifiable or ascertainable at this stage.

The implications of analyzing export-only versus 100% generation, for on-site NEM generation by mass market customers, are significant in that the available CDG tranche sizes under Phase One detailed below are calculated after first accounting for the impact associated with on-site mass market growth. In other words, the potential number of MWs for CDG under Phase One tranches, and bounded by the incremental 2% net annual revenue impact, is reduced when applying net revenue impact to 100% of mass market NEM generation as compared to hourly export-only. Nonetheless, Staff believes that for the purposes of Phase One, it is appropriate to base this analysis on export-only for the reasons discussed above.

3.3.2 Value of DER Phase One Tranches

For CDG projects continuing under the NEM paradigm during Phase One, net revenue impact is based upon the approach taken for mass market, but is based upon 100% of system generation. For CDG projects under the Phase One methodology, net revenue impact is associated with the market transition credit (MTC). As discussed in the report, the MTC is being recommended to supplement the other value components that cannot now be quantified or ascertained. The MTC will also help to avoid disruption of New York's nascent CDG and DER markets, which could result from the limitations of Phase One methodology to include additional or more precise identification and quantification of DER value.

For this analysis, and as discussed in Section 2.10, the analysis assumed that only CDG projects would be eligible for the MTC under Phase One. Therefore volumetric RNM projects, along with large-scale, on-site DER projects, are assumed not to impose net annual utility revenue impact. Staff has thus assumed that the most material impact under Phase One is related to the calculation, application and cost allocation of the MTC, and has therefore focused its analysis as such.

For net annual utility revenue impact associated with the MTC, net impact is equal to the difference between a residential customer's fully bundled volumetric retail rate and a CDG project's value stack according to Staff's recommended Phase One methodology detailed under Section 2.5. Appendix A shows how the compensation values for the estimated value stack are derived. As discussed in Section 2.5.6, distribution value is not being included explicitly as part of the value stack due to the limitations at this stage to precisely identify and quantify all potential values. However, for the purpose of this analysis, distribution value has been included for calculating the net revenue impact and designing Phase One tranches.

As discussed in Section 2.10.1, Staff recommends applying a residential-based MTC to 80% of generation for eligible CDG projects in order to reasonably limit any imbalance of compensation due to variations in CDG customer composition while also providing greater certainty and simplicity in Phase One.

4 Design of Tranches and Analysis Results

4.1 Phase One Tranche Design

To design tranches beneath the incremental 2% net revenue impact boundary, the analysis first estimated the net annual revenue impacts associated with two years of residential mass market growth. When subtracted from the MW volume derived from the 2% boundary, this established sizing to allocate among the CDG tranches. The next step was to decide how to allocate this remaining opportunity to individual tranches. The approach taken balanced the desire to maximize the viability of CDG project development with the desire to maximize the amount of MWs developed given the 2% boundary. In other words, the higher the MTC, the greater the likelihood of project development, and the lower the MTC, the greater the number of potential MWs developed under Phase One. As discussed in Section 2.10.2, the analysis considers the following CDG tranches.

Tranche 0 – Compensation based upon current CDG and NEM rules;

Tranche 1 – Based upon the Phase One methodology, with an MTC set at a level that, when added to Staff's estimated "value stack," yields compensation approximately equal to a residential customer's existing fully bundled volumetric retail rate;[41]

Tranche 2 – Based upon the Phase One methodology, with an MTC set at a level that yields compensation approximately equal to 90% of a residential customer's existing fully bundled volumetric retail rate;

Tranche 3 – Based upon the Phase One methodology, with an MTC set at a level that yields compensation approximately equal to 80% of a residential customer's existing fully bundled volumetric retail rate.

To size the various tranches in each utility, the analysis has weighted 60% of opportunity beneath the 2% boundary to Tranche 0 and Tranche 1, with the remaining 40% evenly distributed to any subsequent tranches.[42] As mentioned, in some utility service territories, MTC calculations under particular tranches may result in a negative number. For those utility

[41] As previously discussed, Tranche 1 will be based upon any remaining capacity left over from Tranche 0.

[42] It should be noted that this weighting has material impact on not only the sizing of tranches, but also the total aggregate MWs under Phase 1, considering that beneath the 2% boundary more opportunity is available under Tranche 3 as compared to Tranches 0 and 1.

territories, if the MTC calculation for a given tranche results in a negative number, there will be no such tranche, and instead prior tranches will be larger. If and after the final tranche is filled, projects will be compensated based on the value stack associated with the Phase One methodology.

For the final step in sizing tranches under Phase One tariffs, the analysis adopted a similar approach to that which was utilized for calculating the MTC. Staff has assumed that CDG projects are comprised of 80% residential customers and 20% commercial customers. Doing so provided a method by which to calculate tranche sizes for Phase One tariffs, which in aggregate, would not exceed the incremental 2% annual net revenue impact for the residential class after accounting for mass market growth. Although this tranche design, bounded by the incremental 2% net revenue impact, would establish opportunity for CDG project development under Phase One, Staff anticipates that the utilities would track and account for actual net revenue impact, and would allocate costs according to the methods described in Section 2.3.3.

Staff anticipates that the queue management restructuring proposal and current SIR rules regarding utility interconnection processes will serve as an important tool for awarding tranche position in an orderly and deliberate manner. This is especially the case with the initial Tranche 0, which Staff suggests opening for 90 business days following a Commission Order on VDER Phase One. Staff recommends that in order for a project to reserve placement in an active tranche, projects must have made an advanced payment to the utility of at least 25% for any system upgrades necessary to accommodate interconnection. If system upgrades are not required, projects that have a fully executed Standard Interconnection Contract with the respective utility would also be eligible to reserve placement in an active tranche.

4.2 Results

Results are provided for illustrative purposes only. These results were arrived at based on numbers as of the issuance of this report. The actual calculation of the MTC, the net revenue impact of mass market projects, and the net revenue impact of projects receiving the MTC will be based on actual numerical inputs in effect at the time of the Phase One Order or a designated date following the Order. Once those calculations have been performed, tranches will need to be recalculated to maintain the fundamental structural recommendations of a maximum incremental net annual revenue impact of 2% and an initial Tranche Zero equivalent to NEM. Upon updating the calculations, reweighting among the tranches may be necessary to achieve these structural recommendations.

Staff observes that net revenue impacts and tranche sizing are influenced by some of the primary inputs and assumptions required for the analysis that were discussed above:

- Two years of estimated mass market solar PV growth;
- Fully bundled volumetric residential retail rates;
- Level of utility revenues per customer class;
- Estimation of value components for representative PV output profiles; and
- Proposed levels of market transition credits and associated allocation of incremental 2% net revenue impact.

Numerical data associated with these and other inputs, which serve as the basis for Staff's analysis, are detailed in Appendix A. Staff fully appreciates that parties will both scrutinize this data and Staff's methodology along with providing feedback. While the results provided here present the products of the analysis, Staff notes that the analysis may be further refined in response to party comment. In addition, as mentioned, numerical inputs will be updated and used for calculation of tranche size at the time of a Phase One Order.

The charts in Appendix B are organized by utility and present the MW capacity associated with the various tranches of projects that Staff has analyzed. Parties will observe that not all utilities include all Phase One tranches 0/1, 2, and 3. As was previously mentioned, in cases where the MTC calculation for a particular tranche results in a negative number, there will be no such tranche and prior tranches will be larger while still remaining under the 2% boundary. Further detail is provided in Appendix C, which will be filed separately in this docket. Appendix C is composed of a series of Excel workbooks which present the data used by Staff for the purposes of illustrating the MTC and tranches that result from the application of the recommendations presented in this report, based on the data available through October 26, 2016.

APPENDICES

APPENDIX A

Methodology for Calculating CDG MTCs ($/kWh produced at DG Meter)

	Definition	Source and Calculation	Unit of Calculation and Result
1.	MTC i = NEM Rate i - Value Stack i	Subtraction, given below calculations	Fixed $/kWh for 20 years
2.	NEM Rate i =		
	SC 1 per kWh Delivery I	Effective on date of NYPSC Order	$/kWh
	+ SC1 MFC	Effective on date of NYPSC Order	$/kWh
	+ SC1 SBC	Effective on date of NYPSC Order	$/kWh
	+ SC1 commodity capacity charge	Monthly average of prior months (for prior 4 capability periods in Hudson Valley; for prior 8 capability periods for other locations), as of NYPSC Order	Average $/kWh for each month of the year, multiply by monthly PV kWh, sum over 12 months, and divide by annual PV kWhs to yield overall $/kWh
	+ SC1 commodity energy charge	Monthly average of prior 5 years, as of NYPSC Order	{Same as above}
3.	Value Stack i =		
	REC Average Annual Price	REC Average Price Reported Publicly by NYSERDA in 2017	$/kWh
	+ SC1 commodity capacity charge	Monthly average of prior months (for prior 4 capability periods in Hudson Valley; for prior 8 capability periods for other locations), as of NYPSC Order	Average $/kWh for each month of the year, multiply by monthly PV kWh, sum over 12 months, and divide by annual PV kWhs to yield overall $/kWh
	+ Hourly DA LBMP	Hourly average of DA LBMP from NYISO for Relevant Zone, grossed up for secondary level losses	each of 8760 hours over the last 5 years, multiply by the hourly PV kWh, sum over the 8760 hours, gross up for secondary level losses, and divide by annual kWh to yield overall $/kWh
4.	Hourly, monthly and annual kWh	From E3 TMY PV Curves for 2 MW facility located in relevant service area	kWh per time period
5.	i	i = each of 6 utilties	

APPENDIX B
Illustrative Results and Tranche Sizes

Figure 5 – Orange and Rockland Utilities, Inc.

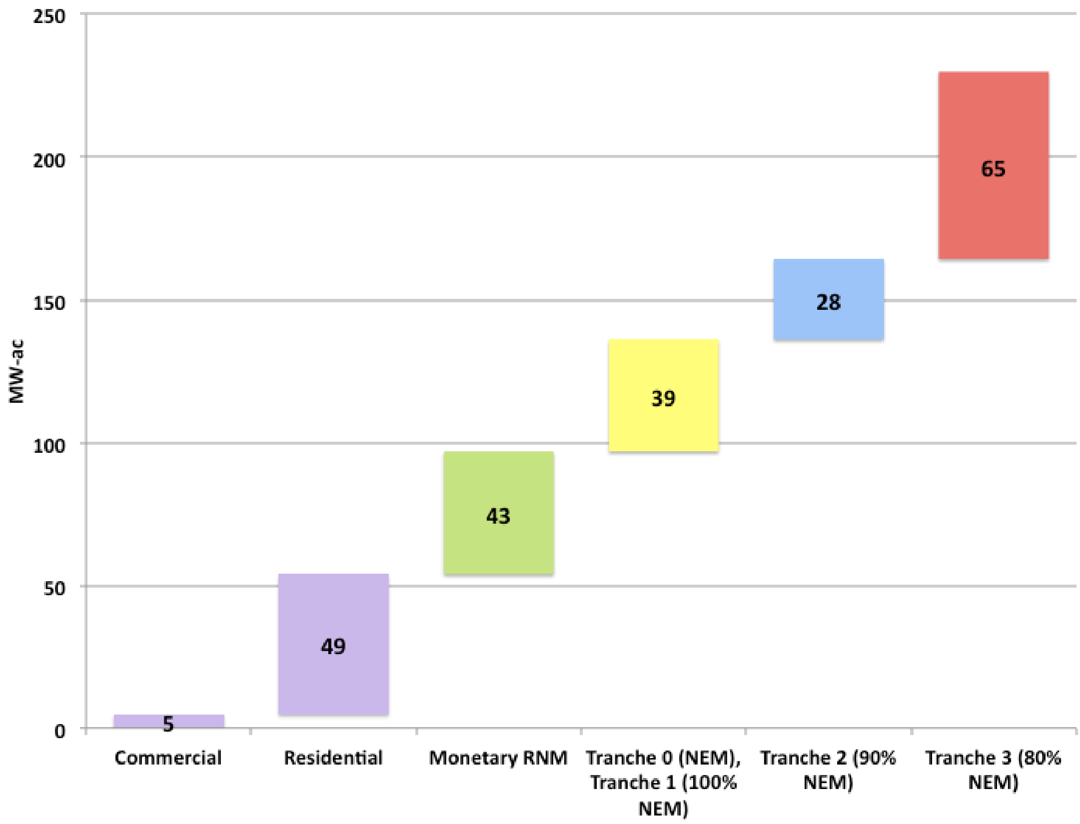
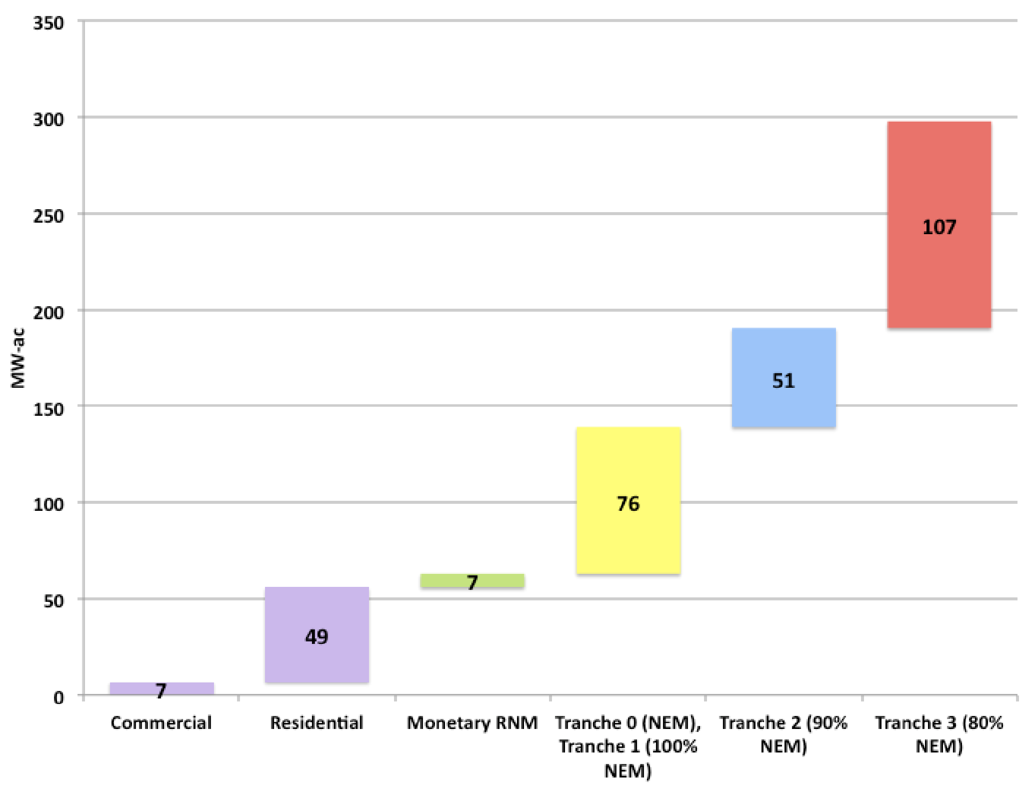


Figure 6 – Central Hudson Gas & Electric Corporation



Appendix B

Figure 7 – New York State Electric & Gas Corporation

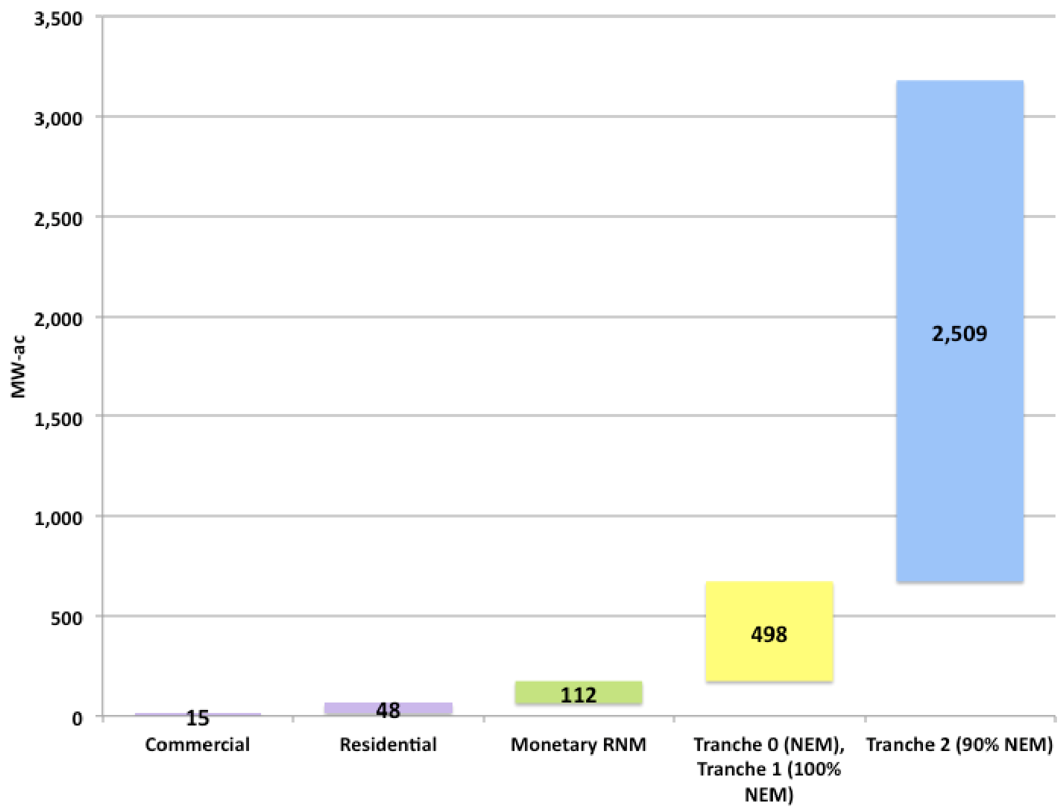
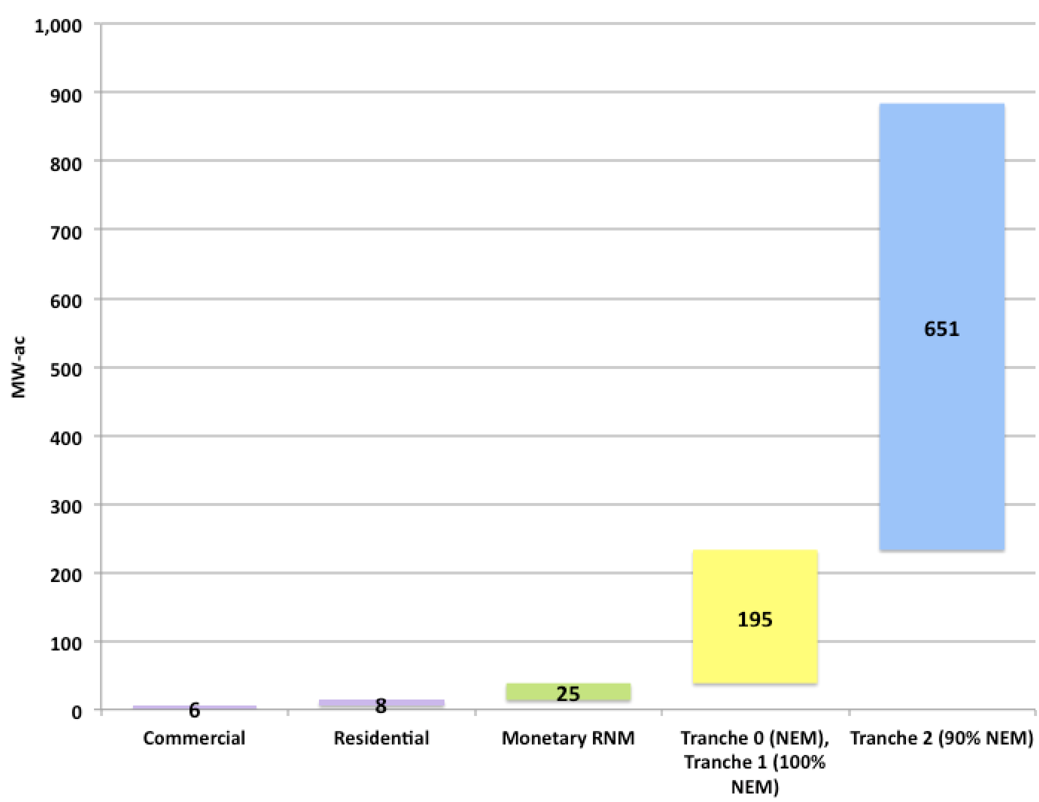


Figure 8 – Rochester Gas and Electric Corporation



Appendix B

Figure 9 – Niagara Mohawk Corporation d/b/a National Grid

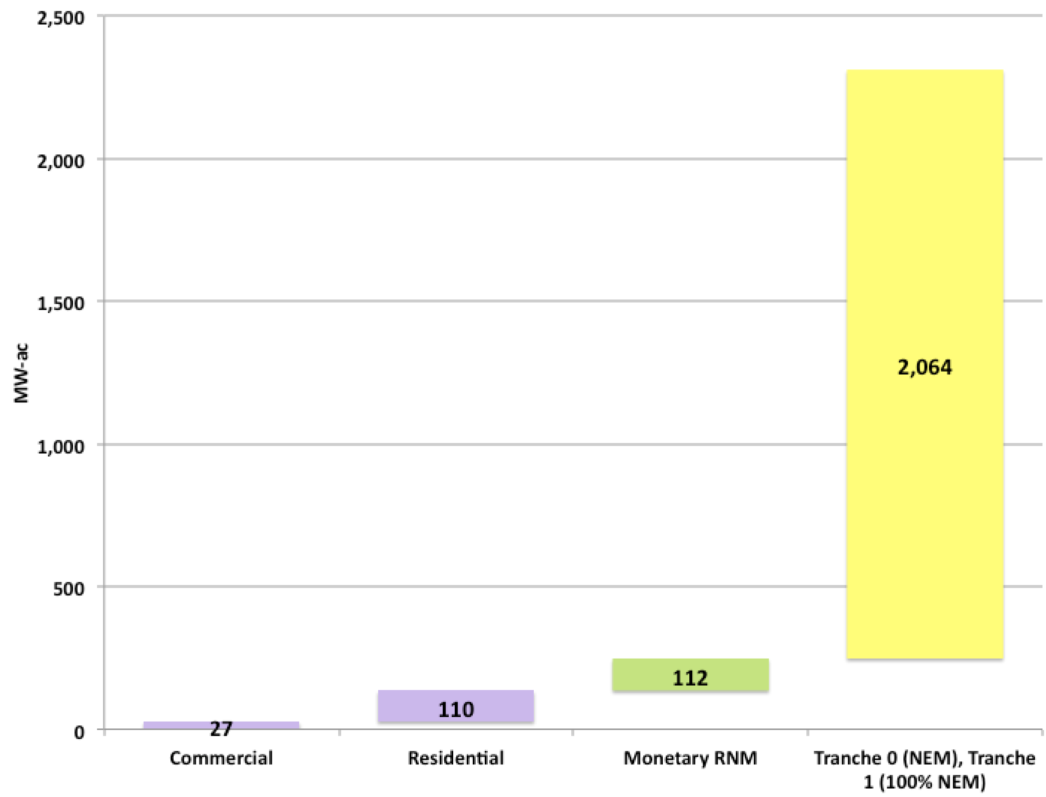
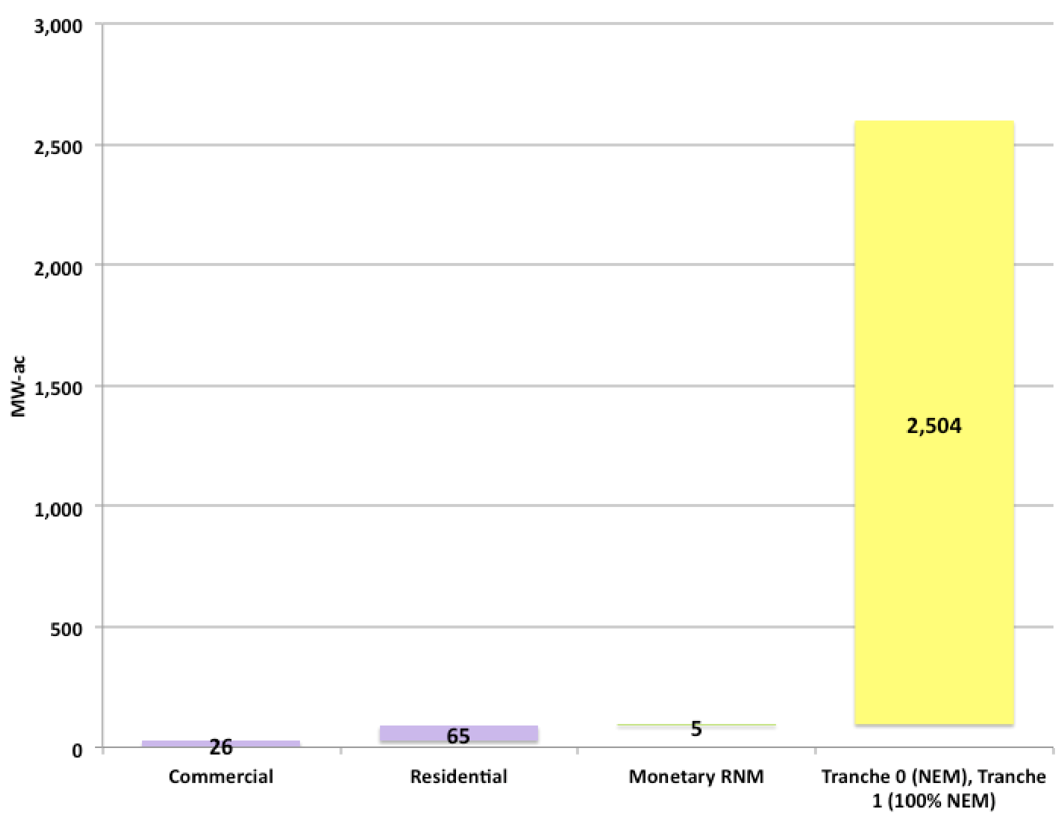


Figure 10 – Consolidated Edison Company of New York, Inc.



APPENDIX C
Excel Workbooks Used for Calculations

Excel workbooks presenting the data used by staff for the purposes of illustrating the MTC and tranches will be available on October 28, 2016 in the Department's Document and Matter Management System (DMM) in Case 15-E-0751. The available workbooks are:

- SUMMARY WORKBOOK.xlsx
- Utility SC 1 Energy Charges.xlsx
- VoD Estimate.xlsx
- Zone B 5 years of DA LBMP.xlsx
- Zone C 5 years of DA LBMP.xlsx
- Zone F 5 years of DA LBMP.xlsx
- Zone G 5 years of DA LBMP.xlsx
- Zone J 5 years of DA LBMP.xlsx
- Solar Simulations for DPS.xlsx
- VDER Staff Report_work papers for tranche sizing.xlsx