

STATE OF NEW YORK  
PUBLIC SERVICE COMMISSION

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

ORDER ESTABLISHING NET METERING SUCCESSOR TARIFF

Issued and Effective: July 16, 2020

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STATE OF NEW YORK  
PUBLIC SERVICE COMMISSION

At a session of the Public Service  
Commission held in the City of  
Albany on July 16, 2020

COMMISSIONERS PRESENT:

John B. Rhodes, Chair  
Diane X. Burman, dissenting  
James S. Alesi  
Tracey A. Edwards  
John B. Howard

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

ORDER ESTABLISHING NET METERING SUCCESSOR TARIFF

(Issued and Effective July 16, 2020)

BY THE COMMISSION:

INTRODUCTION

Through the Value of Distributed Energy Resources (VDER) policy, the Public Service Commission (Commission) has directed the transition of compensation for certain distributed generators (DG) from previous compensation methods with limited accuracy and granularity, such as net energy metering (NEM), to the Value Stack, which provides compensation based on the actual, calculable values that the generator provides to the electric system. These changes have been designed to align compensation with benefits to incentivize deployment of DG in a manner that maximizes benefits for customers, the utility system, and society, while also mitigating the potential for cost shifts onto non-participants at unreasonable and unsustainable levels.

In the VDER Transition Order, the Commission directed the immediate sunset of statutory NEM (NEM) and established the Value Stack as the preferred compensation methodology for eligible DG.<sup>1</sup> The Value Stack provides monetary crediting for net hourly injections based on the actual values provided, including the energy, capacity, environmental, and distribution system values. The Commission also established Phase One NEM as a transitional mechanism which provides compensation generally equivalent to and under the same rules as NEM. Phase One NEM is presently an available compensation option for on-site mass-market<sup>2</sup> DG using NEM-eligible technology, as well as on-site projects serving demand-metered non-residential customers sized under 750 kilowatts (kW).

For projects interconnected after January 1, 2021, the Commission directed Department of Public Service Staff (Staff) to develop a successor tariff to Phase One NEM with stakeholder input. Staff subsequently conducted an extensive collaborative process, including opportunities for submission of proposals and multi-stage evaluation of various options. That process culminated in Staff filing the Rate Design for Mass Market Net

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<sup>1</sup> Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017) (VDER Transition Order).

<sup>2</sup> The VDER Transition Order defines mass market on-site projects as those interconnected behind the meter of a customer within a utility's residential or small commercial service class, not billed based on peak demand, and not used to offset consumption at any other site. Whether a customer qualifies as mass market is based on the default rate applicable to that customer and is therefore not impacted by that customer's decision to participate in an optional rate, such as an optional demand or standby rate.

Metering Successor Tariff Whitepaper (Whitepaper) on December 9, 2019.

Staff recommends in the Whitepaper that on-site mass-market DG using NEM-eligible technology, as well as NEM-eligible on-site projects serving demand-metered non-residential customers sized under 750 kilowatts (kW), continue to have the option to choose Phase One NEM compensation, based on existing delivery rates, for all new projects, but that customers with new on-site solar photovoltaic (PV) generation should be required to continue contributing to the funding of public benefit programs by the application of a monthly Customer Benefit Contribution (CBC) charge of between \$0.69 per kW direct current (DC) of installed PV generation to \$1.09 per kW DC depending on utility and customer class. This modest CBC is in contrast to the monthly \$3.00 per kW DC to \$7.00 per kW DC in estimated potential cost shifts from on-site solar PV adopters using NEM to non-adopters, identified in the Whitepaper.

This Order adopts Staff's recommendations with modifications. NEM has successfully incentivized DG in New York by its simple design and familiarity, and therefore retaining Phase One NEM, with modifications, is the best means currently available to support continued solar development while beginning to address cost shifts and improve incentives. DG projects shall also continue to be eligible for the range of delivery rate options presently offered in utility tariffs, including standard, time-of-use (TOU), and standby rates. Customers that install solar PV technology, interconnected on or after January 1, 2022, shall be charged a monthly CBC charge based on compensation option chosen, customer class, and utility service territory. Staff is instructed to continue its efforts in the Value Stack Working Group process to further refine DG compensation, particularly for technologies other than solar PV.

These actions appropriately balance the need to move the market gradually towards more cost-reflective rates, while at the same time protecting the vibrant DG industry from abrupt and unanticipated rate changes.

#### BACKGROUND

In the VDER Transition Order, the Commission directed the immediate sunset of NEM rates under Public Service Law (PSL) 66-j and 66-l, and established the Value Stack as the preferred compensation methodology for DG technologies like solar PV, farm waste-based anaerobic digesters, wind, micro-hydroelectric, fuel cell, and micro-combined heat and power generation systems. The Commission required new Community Distributed Generation (CDG) projects, remote net-metered projects, and large on-site projects using these technologies to immediately transition to Value Stack compensation.

The VDER Transition Order also established a number of transitional mechanisms to moderate the changeover from NEM to the Value Stack. One of these mechanisms, Phase One NEM, is similar to NEM except that projects are only eligible to receive Phase One NEM for a term of 20 years from the date of interconnection and are not entitled under any circumstance to a cash out of any excess bill credits. Projects eligible for Phase One NEM compensation may also opt into the Value Stack and receive other transitional mechanisms such as the Market Transition Charge (MTC), and its successor, the Community Credit.

In the VDER Transition Order, the Commission directed the use of Phase One NEM for eligible on-site mass-market projects that are interconnected before January 1, 2020. Similarly, in the VDER Compensation Order, the Commission directed that eligible on-site commercial projects with a rated

capacity of 750 kW or lower also have the option to receive Phase One NEM if interconnected before January 1, 2020.<sup>3</sup> For projects interconnected on or after January 1, 2020 (later modified to January 1, 2021),<sup>4</sup> the Commission directed Staff to develop a successor tariff through the VDER Working Group process.

In the VDER Transition Order, the Commission directed that these new compensation rules improve the alignment of DG compensation with the values the resources provide and anticipated that further stakeholder outreach would be initiated by Staff to develop the successor tariff. Staff subsequently formed a number of working groups, including the Rate Design Working Group, to assist in developing recommendations.<sup>5</sup> In recognition of the alignment between the issues identified in the VDER Transition Order regarding mass-market DG projects and the issues raised in the Reforming the Energy Vision (REV) Track Two Order regarding mass-market rate design, Staff explained that the study of mass-market rate design reforms directed in

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<sup>3</sup> Case 15-E-0751, supra, Order Regarding Value Stack Compensation (issued April 18, 2019) (VDER Compensation Order). The project must have the following characteristics: (a) a rated capacity of 750 kW AC or lower; (b) at the same location and behind the same meter as the electric customer whose usage they are designed to off-set; and (c) an estimated annual output less than or equal to that customer's historic annual usage in kWh.

<sup>4</sup> In response to a Staff request on December 9, 2019, the Secretary to the Commission extended the implementation date of the Phase One NEM replacement tariff from January 1, 2020, to January 1, 2021. See Case 15-E-0751, supra, Ruling on Extension Request (issued December 20, 2019).

<sup>5</sup> See Matter 17-01277, the Value of Distributed Energy Resources Working Group Regarding Rate Design.

the REV Track Two Order would be conducted as part of the Rate Design Working Group's activities.<sup>6</sup>

In the REV Track Two Order, the Commission determined that a more refined rate design, with improved price signals and opportunities for participation in distributed energy resource (DER) markets, would benefit consumers and facilitate the accomplishment of REV objectives. The Commission noted that improvements in rate design are essential to a modern electric system and the efficient operation of customer-oriented markets. The Commission found that existing rate design practices contain implicit price signals that discourage customers from engaging with DERs in a manner that optimizes both customer and system benefits. At the same time, the Commission made it clear that efficient cost recovery is only the beginning of rate design and that rates must also be designed to encourage price-responsive behavior to advance policy objectives, including achievement of environmental policies with managed impacts on customer bills.

With that guidance,<sup>7</sup> the REV Track Two Order directed Staff to examine a range of mass-market customer rate reform

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<sup>6</sup> See Case 14-M-0101, Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) (REV Track Two Order) (directing Staff to address a number of rate design issues); Notice of Rate Design Issues to be Addressed in VDER Proceeding (issued July 21, 2017) (assigning a number of the REV Track Two Order Rate Design issues to the VDER Rate Design Working Group); Matter 17-01277 supra, VDER Value Stack and Rate Design Working Group Process and 2018 Schedule (filed December 22, 2017) (including rate design issues in schedule).

<sup>7</sup> The REV Track Two Order also adopted rate design principles to guide the process, including cost causation, encouragement of outcomes, policy transparency, fair value, customer-orientation, price stability, low- and moderate-income access, gradualism, and economic sustainability. Staff utilized these principles to assist in developing the recommendations in the Whitepaper.



scenarios, including consideration of the wider use of TOU rates. TOU rates can encourage customers to move their peak demands to a time that is off-peak for the system (or for the local distribution circuit), when the system savings exceed the cost of shifting. The Commission directed that TOU rates be considered for both commodity and delivery rates and directed evaluation of demand charges and peak-coincident demand charges within mass-market rate designs. The Commission directed Staff to consult with stakeholders to define the scope of a study to analyze the potential impacts of a range of mass-market rate reform scenarios.

Subsequently, Staff conducted an extensive stakeholder process through the Rate Design Working Group, which included opportunities for submission of proposals and multi-stage evaluation of various options. That process and related studies and evaluations culminated in Staff filing the Whitepaper on December 9, 2019. The Whitepaper makes recommendations regarding a successor NEM tariff for on-site mass market projects and other eligible on-site resources sized at under 750 kW and details the stakeholder process used to develop those recommendations. In addition to requesting general comments on the Whitepaper, Staff also requested specific responses on other topics, including rate design principles, delivery rate and compensation options, rate design grandfathering, and other related matters needing stakeholder input.

#### SUMMARY OF WHITEPAPER

The Whitepaper details the work conducted in the Rate Design Working Group and presents the recommendations of Staff based on those efforts. Those recommendations include: (1) continuation of a Phase One NEM compensation option for all eligible on-site mass-market and commercial projects under 750

kW; (2) continuation of eligibility for the range of delivery rate options presently offered in utility tariffs for these projects; and (3) application of a CBC for onsite mass-market solar PV systems. In addition, the Whitepaper requested comments on a number of implementation and other related matters.

Staff proposes that all Phase One NEM eligible projects continue to have the range of options available currently in delivery rates, including standard, TOU, and new optional standby rates.<sup>8</sup> Customers would be allowed to remain on standard rates or TOU rates for a period of twenty years. Staff also recommends that customers with eligible projects should be treated similarly to other customers without DERs, so that, as delivery rates change, the rates for all customers would correspondingly change. As new rate options become available, customers will be allowed to switch to a new underlying rate option. Customers would be allowed to switch among the currently available options once per year at their selected anniversary date, but if the switch is to standby rates the grandfathering rights would be revoked.

While an underlying rate design with more sophisticated rate elements and demand-based price signals is preferred from a system benefits and technology-enabling perspective, Staff notes that the lack of existing customer interval data presents a barrier to sizing DER solutions and estimating adopting customer economics. Given the pending implementation of advanced metering infrastructure (AMI) in some utility service territories and the current lack of historical interval data for residential and small commercial customers,

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<sup>8</sup> Under Staff's proposal, customers opting to use standby rates would receive Value Stack compensation.

Staff concludes that more time is needed to unlock the full suite of rate design reforms envisioned in the REV Track Two Order.

The Whitepaper details the analysis performed in the VDER Rate Design Working Group. This analysis identified estimated potential cost shifts from on-site solar PV adopters using NEM to non-adopters of between \$3.00 per kW DC per month to \$7.00 per kW DC per month, of installed PV generation, depending on utility and customer class. For a typical 6 kW DC project, completely eliminating this cost shift would require approximately \$19 to \$44 per month, depending on customer class. Included in those amounts, along with a number of costs related to the maintenance of the utility distribution system, are the costs of key policy programs that aid low-income customers as well as fund energy efficiency and clean energy programs. NEM customers avoid paying for these programs but directly and indirectly derive benefits from them.<sup>9</sup>

Under Staff's proposal, onsite solar PV projects choosing Phase One NEM compensation, along with standard or TOU delivery rates, would be required to contribute to public benefit programs by the application of a monthly CBC charge of between \$0.69 per kW DC to \$1.09 per kW DC, depending on utility and customer class. Staff notes that these CBC charges are relatively minor amounts compared to the cost shifts identified, and the impact on the economics of solar is also small, ranging from a 3.6% to 7.8% impact on the simple payback of a typical solar system and averaging 5.8% across all utilities and customer classes.

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<sup>9</sup> The Whitepaper identifies the public benefit programs funded through volumetric charges, including low-income programs, utility-administered energy efficiency programs, NY-Sun, the New York Green Bank, and other Clean Energy Fund programs.

Further, under Staff's proposal, eligible Phase One NEM customers would be incentivized to opt into Value Stack compensation. Projects receiving Phase One NEM could continue to opt into the Value Stack and be eligible for the Community Credit. In addition, the CBC would only be applied to self-consumed energy for these customers because the Value Stack already compensates injections based on value, whereas the compensation for self-consumed energy is based on the volumetric kilowatt hour (kWh) retail rate. Self-consumed energy is assumed to be approximately 50% for a typical residential solar project and 30% for a small commercial project.<sup>10</sup>

For other projects using NEM-eligible technologies besides solar, for mass-market solar customers choosing new optional standby rates, and for commercial projects up to 750 kW, the CBC applicability has not yet been determined. Staff requested comments in the Whitepaper on the CBC applicability and amount for these other project types.

The Whitepaper also requested stakeholder comment on a number of implementation and other related matters: (1) are there recommended alternative ways to apply the rate design principles detailed in the Whitepaper in establishing the successor tariff; (2) are the proposed delivery rate and compensation options sufficient to allow projects to be economically viable; (3) should customers choosing standard or TOU delivery rates be allowed to remain on those options for some period of time (e.g. 20 years); (4) are higher or lower CBC levels appropriate and if so, what levels, based on what methodology, and according to what principles of rate design; (5) how should the CBC change in the future; (6) how should New

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<sup>10</sup> See Case 15-E-0751, *supra*, Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding (issued October 27, 2016).

York transition to more cost reflective electric delivery and supply rates, both as a default and as an option; and (7) what specific outreach and education approaches and tools (e.g. online rate calculators) would enable customers to increase uptake of the new rate design options?

#### PUBLIC NOTICE

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rulemaking was published in the State Register on December 24, 2019 [SAPA No. 15-E-0751SP31] (SAPA Notice). The time for submission of comments pursuant to the SAPA Notice expired on February 24, 2020. In addition, the Secretary to the Commission issued a Notice Soliciting Comments on the Staff Mass Market Net Metering Rate Design Whitepaper on December 17, 2019 (Secretary's Notice). Pursuant to the Secretary's Notice, initial comments were due on February 24, 2020, with reply comments due on March 16, 2020. The comments received are summarized in Appendix C, and are addressed in relevant part below.

#### LEGAL AUTHORITY

As described in the VDER Transition Order, the Commission has the authority to direct the treatment of DER by electric corporations pursuant to, inter alia, PSL §§ 5(2), 66(1), 66(2), and 66(3). Pursuant to the PSL, the Commission determines what treatment will result in the provision of safe and adequate service at just and reasonable rates consistent with the public interest.

#### DISCUSSION

The Commission's policies, including VDER and NY-Sun, have driven the rapid deployment of DG resources, particularly

solar PV, in New York State. More than 2,200 megawatts (MW) of distributed solar PV is currently in service, with more than 1,000 MW more in advanced stages of development. To meet the ambitious target established in the Climate Leadership and Community Protection Act (CLCPA) of 6,000 MW of distributed solar PV by 2025,<sup>11</sup> the Commission recently authorized additional funding for NYSERDA's successful NY-Sun program.<sup>12</sup> At the same time, the Commission's careful stewardship of ratepayer funds has resulted in more solar PV being built at a lower cost to ratepayers. As noted in the recent NY-Sun Expansion Order, while approximately \$1 billion was allocated to NY-Sun to support the initial 3 GW target, the State expects to be able to stimulate the development of an additional 3 GW with only approximately \$500 million in additional funds. This cost reduction is even more dramatic when taking into account the fact that the VDER policy has resulted in a substantial reduction in the cost of additional solar PV to nonparticipating ratepayers and the appropriately large portion of the incremental funds allocated to supporting disadvantaged communities. The NY-Sun incentive program and the VDER compensation policy are complementary policies that the Commission has managed and will manage in a coordinated manner to stimulate solar development at the necessary levels to support the clean energy economy and meet State policy goals, while also appropriately managing ratepayer funds and ensuring

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<sup>11</sup> See PSL §66-p; Chapter 106 of the Laws of 2019.

<sup>12</sup> See Case 19-E-0735, New York State Energy Research and Development Authority Requesting Additional NY-Sun Program Funding and Extension of Program Through 2025, Order Extending and Expanding Distributed Solar Incentives (issued May 14, 2020).

that solar PV is deployed in ways that provide the greatest benefits for customers, the utility system, and society.

The Whitepaper's recommendations, developed through considerable stakeholder input and an extensive working group process, strike a careful balance between these goals. They reflect the Commission's intention to better align compensation with the values created by DERs, while also following the rate design principles articulated by the Commission in the REV Track Two Order, including gradualism and customer orientation. They represent an appropriate first step towards more cost-reflective rates and economic sustainability by recognizing the need for changes to be measured, gradual, and appropriately scaled based on conditions in the marketplace.

The Whitepaper accomplishes this balance by maintaining the basic NEM structure for on-site mass-market projects while beginning to gradually adjust the rates for new projects to address identified cost shifts. This addition of the relatively minor monthly CBC charge to the existing and well-understood NEM compensation methodology will ensure that solar developers and prospective customers are not required to conduct a complex and potentially impractical analysis in order to understand the benefits and costs of installing solar PV.

The Whitepaper is also consistent with long-standing Commission policy on rate-design. As explained in the REV Track Two Order, rates should encourage desired market and policy outcomes, but changes to rate design formulas and rate design calibrations should not cause large abrupt increases in customer bills or delivery rate impacts. According to the Whitepaper, for a typical 6 kW solar PV project, completely eliminating the estimated cost shift from participants to non-participants would violate all of these principles by potentially requiring \$19 to \$44 per month from a participating customer. Applying these

charges to solar PV adopters would have detrimental effects on the clean energy industry, would violate the rate design principles described in the REV Track Two Order, and would threaten achievement of the State's clean energy goals.

However, the Commission must balance the need for stability of rates and support of the clean energy industry with the reality of cost shifts. In particular, the costs that on-site NEM customers are able to avoid include contributions to key policy programs that aid low income customers and support energy efficiency and clean energy programs. NEM customers avoid contributing to these programs at the same level as non-participating customers, but nevertheless directly and indirectly derive benefits from the programs. According to the Whitepaper, most, if not all, of the mass-market customers installing on-site generation received an incentive from NY-Sun or a similar program paid for through these charges. As these customers have received support in their adoption of clean energy technology from these programs, it is appropriate for them to continue to support these programs to help others receive the benefits of clean energy. Through the transition to Value Stack compensation, subscribers to CDG projects and large customers with on-site or remote net metering projects now contribute fully to these public benefit programs. Adopting the recommendations in the Whitepaper will ensure that, at least for now, solar DG customers will contribute to these important programs.

#### Phase One NEM

The Commission adopts Staff's proposal to continue the availability of Phase One NEM for on-site mass-market projects with the addition of the CBC. Phase One NEM remains a simple and effective mechanism for smaller DER projects. As discussed in the Whitepaper, applying the Value Stack or a similarly



complex mechanism to these projects would, in many cases, require expensive metering and would require mass-market customers to understand a complex crediting framework that is very different from the billing models they are familiar with. Furthermore, unlike in the case of CDG, it would be difficult or impossible for a third party, like a CDG sponsor, to act as an intermediary and take responsibility for reviewing credits received and ensuring that customers benefit. Maintaining a close variation of today's structure will retain this simple model by giving customers and vendors an option with which they are familiar, while AMI continues to be deployed and more sophisticated mass-market rate designs are developed.

The Commission also adopts the extension of the Phase One NEM compensation option to all on-site projects below 750 kW serving non-residential, demand-metered customers. As these customers are already subject to demand rates, this option results in minimal or no cost-shifting impacts. These commercial customers receive compensation from Phase One NEM that is much more aligned with utility costs than non-demand-metered customers, since the delivery portion of their bill is primarily based on a demand charge that is only reduced by distributed generation to the extent that the generator actually lowers the customer's demand.

While most commenters support the continuation of Phase One NEM, the Joint Utilities<sup>13</sup> argue that NEM pricing does not conform to the Commission's rate design principles and has outlived its original purpose of incentivizing early adopters of

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<sup>13</sup> The Joint Utilities are Central Hudson Gas & Electric Corporation (Central Hudson), Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation d/b/a National Grid (National Grid), Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas and Electric Corporation (RG&E).

a nascent technology. The Joint Utilities argue that NEM perpetuates the unwarranted shifting of cost burdens among customer groups and does not create efficient price signals. The Joint Utilities further argue that rate designs, like NEM, are not an appropriate vehicle for encouragement of particular technologies, and should be replaced by programmatic incentives like NY-Sun. The Joint Utilities argue that demand-based rates for delivery and time-varying rates for supply should be used instead. The CEP, by contrast, comment in opposition to demand-based rates for mass-market DER customers, arguing they do not reflect cost causation principles, will act to discourage investment in DERs, reduce low- and moderate-income (LMI) customer participation in energy efficiency programs, and act only to support utility revenues.

While the Commission recognizes that Phase One NEM will continue to result in some level of cost shift, Phase One NEM is an appropriate transitional mechanism and will begin to address those cost shifts. Phase One NEM, with the addition of the CBC, balances the need to move compensation towards a more cost-based orientation with the importance of offering a simple and well-understood methodology to the DER industry. Moreover, NEM is not limited to a single technology and treats all eligible technologies equally. The focus on solar PV in the Whitepaper is a result of the current dominance of solar PV among new mass-market NEM projects and the complexity of the cost-shift evaluation.

The New York Power Authority (NYPA) argues for a consistent application of proposed delivery rate and compensation options to projects that self-consume and net-inject energy. NYPA and the New York State Office of General Services (OGS) argue that the Value Stack is flawed and suggest that Tier 1 renewable energy credits (RECs) should be made

available to behind-the-meter (BTM) projects ineligible for Value Stack compensation. NYPA also notes that customers that forgo the Environmental Value for the opportunity to participate in the voluntary market lose this form of payment. Finally, NYPA suggests that the Commission permit aggregation of smaller projects in a managed REC project portfolio.

The Commission rejects NYPA's Environmental Value suggestions since its proposals would in most cases lead to double recovery for environmental attributes, either through the voluntary market or through Phase One NEM. Moreover, recent actions by the Commission to require energy service companies (ESCOs) offering "green" electric service to purchase RECs with the same locational and delivery requirements as Tier-1-eligible RECs should increase the value of RECs in the voluntary market by increasing the demand for renewable generation in the State.<sup>14</sup>

#### Delivery Rate Options

The Commission adopts Staff's proposals on delivery rate options, with modifications. Customers receiving Phase One NEM compensation shall be permitted to elect any underlying delivery rate design of their choosing, including standard, TOU, and standby rates, with standard rates remaining the default. While rate designs with more sophisticated rate elements and demand-based price signals better align utility costs with customer bills, the lack of existing customer interval data presents a barrier to sizing DER solutions and estimating customer economics. Given the pending implementation of AMI in some utility service territories and the current lack of historical interval data for residential and small commercial

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<sup>14</sup> See Case 15-M-0127 et al., Eligibility Criteria for Energy Service Companies., Order Adopting Changes to the Retail Access Energy Market and Establishing Further Process (issued December 12, 2019).

customers, more time is needed to unlock the full suite of rate design reforms envisioned by the REV Track Two Order.

However, TOU rates that accurately capture seasonal and intraday cost fluctuations will play an important role in an electric system with significant amounts of variable renewable energy, and will likewise ease the transition to more complex rate designs in the future. Phase One NEM customers choosing the TOU option shall receive monetary crediting for injections so that these intraday and seasonal pricing differences are fully captured.

The new standby rates will also be an option available to mass-market DG customers.<sup>15</sup> These rates are most likely to benefit customers with multiple DER technologies, such as solar PV coupled with energy storage and electric vehicle charging, who are interested in more actively managing their energy usage. Since the new standby rates will be more cost-based than existing standard and TOU rates, and will be used by more engaged prosumers, it is appropriate to value their injections via the Value Stack. Therefore, customers choosing standby rates shall receive compensation for injections based on Value Stack compensation, rather than Phase One NEM.

In adopting a new policy, it is important to offer adopters some level of certainty that they can rely on that new policy for a meaningful period of time. Consistent with the recommendations in the Whitepaper, customers that install solar PV or another eligible resource and choose to receive Phase One NEM consistent with the decisions made in this Order, shall

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<sup>15</sup> The Commission directed the utilities to develop optional standby rates for mass market customers, and it is anticipated these rates will go into effect in the second or third quarter of 2020. Case 15-E-0751, supra, Order on Standby and Buyback Service Rate Design and Establishing Optional Demand-Based Rates (issued May 16, 2019).

continue to be entitled to remain on Phase One NEM along with the rate type they choose, such as the standard or TOU rate, for a period of no less than twenty years. However, any changes in standard rate design, or another selected rate type such as TOU, that apply to mass-market customers served under the same rate type without DG, shall similarly apply to mass-market customers with DG. This is consistent with long-standing Commission policy, under which NEM and Phase One NEM customers have been subject to the same rate level and rate design changes as non-NEM customers.<sup>16</sup>

In addition, Phase One NEM customers shall be allowed to switch underlying rate options once per year at their selected anniversary date. Phase One NEM Customers may switch to any rate design available at the time when they switch, including new options that become available subsequent to this Order. The Commission will allow the same switching rights for customers opting into standby rates, in contrast to Staff's proposal. To do otherwise would inhibit the incentives for customers to switch to these more cost-reflective and beneficial rates. Finally, to the extent that new NEM customers require new meters that differ from meters used for non-DG customers, the Commission adopts Staff's recommendation that those costs shall continue to be charged to NEM customers rather than socialized to non-participants.

The City of New York (the City) and Distributed Sun, LLC. (DSUN) comment that Phase One NEM customers should be grandfathered into a particular rate design, such as the current standard rate design or the current TOU rate design, because the potential for the delivery rate design to change could undermine

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<sup>16</sup> This policy is also consistent with PSL §§ 66-j and 66-l and will continue to apply to NEM customers served under those statutes.

the economics of DER projects. This sort of delivery rate grandfathering is not appropriate, as it would offer Phase One NEM customers a greater degree of protection from rate design changes than any other customers receive.

The Joint Utilities disagree with rate design grandfathering and argue that existing volumetric TOU delivery rates are not the most effective approach for charging Phase One NEM customers. The Joint Utilities also argue that combining TOU rates with monetary crediting will result in further cost shifts to non-participants because monetary crediting allows customers with on-site DER to inject during peak hours and then offset the increased cost through greater usage in off-peak periods. Furthermore, the Joint Utilities state that using monetary crediting with TOU rates encourages DER system oversizing and therefore increase impacts upon non-participants. Contrary to these arguments, the Commission directs that TOU rates remain an option for Phase One NEM customers as monetary crediting will incentivize DER adopters to consume less energy and to inject energy at peak times when it is most valued, and to shift energy usage to non-peak times. As the analysis in the Whitepaper demonstrates, TOU rates result in supply compensation better aligned with system value but can result in increased delivery cost shifts. Staff should continue to work with the utilities and other stakeholders through the Rate Design Working Group to design improved TOU rates.

#### CBC Applicability

The Commission adopts Staff's proposal to begin recovery of public benefit program costs from mass-market customers installing solar PV through the application of a monthly CBC charge of \$0.69 per kW DC to \$1.09 per kW DC, depending on utility and customer service class, as detailed in Appendix B. The CBC amounts are relatively minor in comparison

to the total estimated cost shifts identified in the Whitepaper, but represent an important first step, and ensure that certain Phase One NEM customers fairly contribute to these important programs. The impact on the economics of solar is also small, ranging from a 3.6% to 7.8% impact on the simple payback of an average mass-market on-site solar PV project.

The level of the CBC charge shall be updated regularly to account for changes in public benefit program costs. Adjustments will not impact the solar adopter's original investment, but instead will minimize windfalls that could occur if collections for the public benefit programs are increased in the future. The updates to the CBC will be based directly on changes to collections for the public benefit programs from non-NEM customers; therefore, the CBC charge could go up or down, as public benefit program collections change, and in no case will a Phase One NEM customer see a greater increase in their bill from the change in the CBC charge than non-NEM customers see from an increase in collections for the public benefit programs.

For customers choosing Value Stack compensation instead of Phase One NEM, the Commission adopts Staff's proposal to reduce the CBC charge for these customers. The CBC charge shall only be applied to estimated self-consumed energy for these projects. This discounting is appropriate because the Value Stack compensation for injections has been fully decoupled from the retail rate and therefore does not result in avoided contributions to public benefit programs.

For other projects, such as large on-site solar projects, those using the new mass-market standby rates or TOU rates, and all other projects using NEM-eligible technologies besides solar, a specific CBC level was not proposed in the Whitepaper. The CBC charge calculations in the Whitepaper are based on passive, non-tracking, solar PV customers using

standard rates. Additional eligible DER technologies include residential micro-combined heat and power, fuel cells, micro-hydroelectric generators, and farm waste digesters. As the characteristics of these resources are substantially different from solar PV, the same CBC will not be applied. Therefore, utilities are directed to file proposed CBCs for PV adopters choosing standby or TOU rates and for non-PV NEM eligible technologies adopters by November 1, 2020. Staff is directed to evaluate the filings and hold stakeholder discussions of such in the VDER Rate Design Working Group. This schedule should allow for Commission review and decision followed by utility compliance filings that include CBCs for all combinations of NEM-eligible technologies and rates, to be filed by July 1, 2021, to become effective on January 1, 2022.

Commenters are mixed on whether Staff's proposed CBC strikes the correct balance. The Joint Utilities argue that the recommended CBC does not capture approximately 82% of the residential cost shift identified in the Whitepaper, and supports an increasing CBC over five years, followed by implementation of demand rates for mass-market DER adopters. The Joint Utilities believe that the CBC should recover both public benefit program costs and other costs incurred by utilities to serve customers and the public. They add that, at a minimum, the CBC should be updated to account for changes in volumetric delivery rates and public policy costs.

In addition, the Joint Utilities support applying the CBC to all NEM-eligible technologies, consistent with technology neutrality, as all would otherwise avoid payment toward customer benefit programs. The Joint Utilities propose that the CBC for customers receiving Value Stack compensation vary by utility, with a discounted CBC possibly being appropriate for utilities that have fully exhausted their MTC or Community Credit



allocations. They point out that Con Edison customers who opt into the Value Stack have eligibility for the \$0.12 per kWh Community Credit, and therefore a fully discounted CBC is not necessary until the Community Credit is fully subscribed.

While the CEP generally supports a modest CBC to recover costs for specific public benefit programs, it argues that the proposed CBC is a significant increase for future solar customers. If the CBC is adopted, the CEP requests that Staff should provide clear guidelines as to what cost categories should be included and argues that only the LMI program costs should be included. The CEP contends that a clear statewide process for updating the CBC should be adopted. The CEP recommends the CBC be capped at a fixed amount, suggesting \$0.50 per kW per month as a potential cap. DSUN similarly recommends a limit on any annual increase of the CBC to enable financial models to accurately describe future cost exposure and its impacts to total returns of the project.

The CEP opposes the Joint Utilities proposal to gradually increase the CBC over five years and then implement demand-based rates. The CEP opines that such continual adjustments to the CBC would introduce serious uncertainty in the DER market which would act to reduce solar deployment. The CEP states that when the Salt River Project utility in Arizona assessed higher fixed charges and demand charges upon solar adopters, there was a 75% decrease in solar rooftop installations.

The City supports the CBC as a long-term solution, and possibly the ultimate successor tariff, because an as-yet unknown successor tariff could have a negative effect on certainty. However, the City cautions that that future adjustments to the CBC should be predictable and gradual, not be assessed to LMI households who already face barriers to adoption

of DER, and should be informed by further analysis of the economic impacts associated with different delivery rates, compensation methods, and DER models to balance impacts upon non-participants and supporting robust DER deployment. The City also warns that different models of DER implementation could be adversely affected by the CBC. In a PPA model, for example, the customer receives only a portion of the NEM benefits but pays the entire CBC. The City requests that Staff analyze these disparities and address them accordingly.

The City proposes that until such time as there is evidence of an undue impact from rates other than standard and TOU delivery rates, the CBC should not be applied to customers electing such alternate rates. The City agrees that there is no evidence that DERs on standby rates shift costs to non-participants and therefore there is no need to impose a CBC on standby rate customers. DSUN agrees that the CBC should be assessed in a technology-neutral manner. NYPA argues that the CBC should not be imposed upon its economic development customers.

The Commission is cognizant of the utility costs that are still being avoided by customers who adopt Phase One NEM, including for items such as cyber security, emergency services, and safety programs, as well as costs associated with the secondary distribution system used to deliver injected power into neighboring load sources. However, a CBC based specifically on public benefit programs is an appropriate first step. As discussed above, it results in a CBC level that will not unreasonably impede solar PV deployment but will begin to address the cost shifts. In addition, the CBC will ensure that Phase One NEM customers contribute at an appropriate level to programs that create broad societal benefits, some of which many solar PV customers have themselves taken advantage of. This

decision is also consistent with California's decision to impose non-bypassable charges on NEM customers to recover costs of low-income and clean energy programs.

Most commenters argue that commercial solar projects under 750 kW with a demand meter and those opting into the new mass-market standby rates should not pay the CBC. The Joint Utilities argue that properly designed demand charges should reflect customer benefit charges and that the new standby rates should also limit any cost shift because the vast majority of delivery costs would be recovered in demand charges. They qualify these remarks by declaring that a small CBC may still be appropriate for these customers to capture costs not covered in demand charges. The CEP and the City argue that commercial customers paying demand charges, typically those with demand greater than 10 kW, should be exempt from the CBC. DSUN undertook financial analysis of this issue and determined that imposing a CBC on NYSEG, RG&E and National Grid customers in this category would make these projects not viable even with a reduced CBC. While the Commission believes these arguments have merit, as described above the Commission directs utility filings followed by further evaluation in the VDER Rate Design Working Group to fully analyze the appropriate CBC to apply to such customers.

#### Implementation Timeline

The Commission is delaying the implementation of the changes adopted herein for an additional year due to the direct and indirect effects of the COVID-19 pandemic on businesses, including the critical clean energy economy of New York. The Whitepaper recommended that the NEM successor tariff become effective by January 1, 2021. On May 7, 2020, the CEP filed a request with the Commission to delay the implementation of the NEM Successor Tariff to December 31, 2022, due to severe

industry disruption caused by COVID-19. In its request, the CEP noted some estimates suggesting that new DG business will decline by up to 75% as a result of the COVID-19 pandemic and stated that it expects the New York solar industry to lose more than 9,000 jobs in June 2020. New York installation activity for 2020 is forecasted to be at least 48% lower than 2019, with the residential market facing the steepest forecasted decline at 59% below 2019 installations.

Both the Commission and NYSERDA have taken action to address these impacts, including suspending interconnection deadlines and accelerating certain incentive payments. The Commission takes this further action to support affected industries during this period of uncertainty. Therefore, the Commission directs the Joint Utilities to file proposed tariff amendments implementing the decisions herein by November 1, 2020 for Commission review, with the expectation that the Commission will direct final tariff leaves to be filed by July 1, 2021, to be effective on January 1, 2022.

#### CBC Calculation

The Commission directs the utilities to recover the public benefit program costs identified in the Whitepaper through a separate CBC surcharge calculated on a dollar per kW DC installed per month basis, updated annually. The CBC surcharge should be effectuated by filing tariff amendments incorporating the directives discussed herein, as well as filing a separate tariff statement, "Customer Benefit Contribution Statement" (CBC Statement), that shall contain the CBC for each service class, rate category, and project type and shall be updated annually. The CBC surcharge contained in the CBC Statement should be calculated based on collections for the Utility Low Income Programs, the Utility Energy Efficiency Programs, and the Clean Energy Fund, including NY-Sun and the

New York Green Bank. For each public benefit program, the utilities shall recover the associated costs from new Phase One NEM customers through the CBC surcharge.

In order to calculate the CBC surcharge, each utility must first determine the amount collected for each public benefit program from non-NEM customers in the appropriate service class on a \$/kWh basis. Clean Energy Fund costs are recovered through the System Benefits Charge on a \$/kWh basis that is updated annually. Therefore, the portion of the CBC based on the Clean Energy Fund will be calculated each December for each service class using the \$/kWh surcharge amount for the upcoming year to be collected from the applicable service class for Clean Energy Fund programs. Where a utility recovers part or all of the costs of its Utility Energy Efficiency Program through the SBC and the related Energy Efficiency Tracker mechanism, the utility shall also include those \$/kWh surcharges for the applicable service class when calculating the CBC. For Utility Energy Efficiency Program costs collected through base delivery rates, the utility shall calculate the portion of the CBC related to those costs each December by using the actual Commission approved program budget for the upcoming calendar year. That program budget shall be first allocated to the individual service classes based on the percentage of delivery revenues assigned to each service class from the most recent approved utility rate case filing. Then the portion allocated to the applicable service class shall be divided by the total kWh sales volume for that service class for the previous twelve months, resulting in a \$/kWh figure for those costs. Similarly, Utility Low Income Program costs are embedded in and recovered through each utility's base delivery rates. To determine the appropriate CBC amount for those programs, the utility shall take actual expenditures during the previous twelve months for

Utility Low Income Programs, allocate those expenditures to the individual service classes based on the percentage of delivery revenues assigned to each service class from the most recent approved utility rate case filing, and divide the portion allocated to the applicable service class by the by the total kWh sales volume for that service class for the previous twelve months. This will result in a \$/kWh figure for Utility Low Income Programs.<sup>17</sup>

For each service class, the utility shall then add together the \$/kWh figures for the Clean Energy Fund, Utility Energy Efficiency Programs, and Utility Low Income Programs. The resulting \$/kWh figure shall then be multiplied by the expected annual generation for 1 kW DC of rooftop solar, shown in the below table, to determine the CBC per kW DC of solar per year.<sup>18</sup> That number shall then be divided by 12 to arrive at the monthly CBC. The monthly CBC for each service class shall be listed in the Customer Benefit Contribution Statement and each customer to whom the CBC applies shall be billed each month at the current CBC multiplied by the nameplate capacity in kW DC of that customer's solar PV system.

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<sup>17</sup> Phase Two of the Commission's Energy Affordability Policy is ongoing and is considering modifications to the policies and benefits for low income consumers. Case 14-M-0565, Programs to Address Energy Affordability for Low Income Utility Customers. If the Commission adopts changes to the development of the annual low-income budgets in that proceeding, the low-income surcharge calculation process described above shall be modified to use the budgets established in that proceeding.

<sup>18</sup> In calculating the proposed CBC for other technologies, utilities should start from the same \$/kWh figure and multiply it by the expected annual generation of the relevant resource.

Average Annual Generation of 1 kW DC Solar by Utility Territory<sup>19</sup>

Central Hudson	Con Edison	National Grid	NYSEG	O&R	RG&E
1176	1244	1144	1126	1246	1152

The utilities are also directed to update the CBC surcharge on an annual basis, with the first update to be effective on January 1, 2023. The annual CBC Statement shall be filed at least 30 days prior to the January 1 effective date of the CBC update. The CBC Statement shall reflect the CBC surcharge as calculated and recovered from customers consistent with the description for each of the public benefit costs discussed above. The utilities' annual CBC surcharge filings should include supporting workpapers.

Other Matters

Staff recommends in the Whitepaper that the VDER Rate Design Working Group use the prioritization framework identified in the Whitepaper to rank options and narrow down mass-market successor rates that can also serve as broader technology-agnostic rates able to meet State goals. Through the continuation of the Rate Design Working Group, stakeholders should craft rate options that enable new technology adoption and meet State policy goals in an economically efficient manner. While widespread implementation of these rates may have to wait until a full year of detailed AMI data is available to a customer, these new rate designs can be offered as additional customer options much earlier. The Commission encourages Staff

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<sup>19</sup> These values were derived from the solar production data for south-facing roof-mount solar PV systems collected by NYSERDA and available in the NYSERDA Value Stack Calculator, available at <https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Contractors/Value-of-Distributed-Energy-Resources/Solar-Value-Stack-Calculator>.

to perform these analyses as the Rate Design Working Group continues to meet through 2020 and 2021.

A number of commenters also provided input on tools that increase customer awareness and understanding of different rates and how to manage their usage and costs, including online rate calculators and utility messaging. The Commission supports continued consideration of such tools as part of the Rate Design Working Group and development of tools deemed beneficial.

As recommended by the Whitepaper, the standard customer disclosure forms that must be provided to mass-market DG customers under the Uniform Business Practices for Distributed Energy Resources Suppliers (UBP-DERS) must be updated, prior to the effective date of the CBC, to include clear disclosure of the CBC charge. The Commission directs Staff to issue an updated form by December 31, 2020.

#### CONCLUSION

Continuing and accelerating the pace of distributed solar deployment in New York will support the continued development of a clean, distributed, dynamic, and efficient electric grid. The decisions made in this Order, coupled with our recent NY-Sun Order, will support the continued deployment of distributed solar at scale in New York while managing impacts on non-participating ratepayers. This Order also takes the first steps towards better aligning residential rate design with cost causation and towards encouraging mass-market customers to deploy DERs in a manner that provides the greatest benefits to customers, the utility system, and society.

#### The Commission orders:

1. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State



Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation are directed to file, in conformance with the discussion in the body of this Order, proposed draft tariff leaves and a proposed draft tariff statement implementing the Customer Benefit Contribution charge by November 1, 2020, for Commission review.

2. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation are directed to file, in conformance with the discussion in the body of this Order, proposed Customer Benefit Contribution calculations for solar photovoltaic (PV) customers choosing standby or TOU rates and for customers with non-PV net energy metering eligible technologies by November 1, 2020, for Commission review.

3. Department of Public Service Staff shall issue an updated standard disclosure statement for mass-market distributed generation customers including information on the Customer Benefit Charge by December 31, 2020.

4. In the Secretary's sole discretion, the deadlines set forth in this order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least one day prior to the affected deadline.

5. This proceeding is continued.

By the Commission,

(SIGNED)

MICHELLE L. PHILLIPS  
Secretary

SUMMARY OF NEM SUCCESSOR TARIFF

NEW ON-SITE SOLAR PV PROJECTS				
Project Type	Delivery Rate	Compensation Options	CBC Applicability (% of Total Charge)	Other
Mass Market	Standard	Phase One NEM	100%	
		Value Stack	50% residential 30% small commercial	
	TOU	Phase One NEM	TBD	Monetary crediting
		Value Stack	TBD	
	Optional Standby	Value Stack	TBD	
Commercial (<750 kW)	Standard, TOU, Legacy Standby	Phase One NEM	TBD	
		Value Stack		

NEW ON-SITE NEM-ELIGIBLE PROJECTS (Non-Solar PV)				
Project Type	Delivery Rate	Compensation Options	CBC Applicability (% of Total Charge)	Other
Mass Market	Standard	Phase One NEM	TBD	
		Value Stack	TBD	
	TOU	Phase One NEM	TBD	Monetary crediting
		Value Stack	TBD	
Optional Standby	Value Stack	TBD		
Commercial (<750 kW)	Standard, TOU, Legacy Standby	Phase One NEM	TBD	
		Value Stack		

Estimated CBC Charges



Customer Benefit Contribution Statement

Customer Benefit Contribution Statement		
Service Classification	Compensation Options	CBC Rate (\$/kW DC)
Residential	Phase One NEM	
	Value Stack	
Small Commercial	Phase One NEM	
	Value Stack	

SUMMARY OF COMMENTSCommenters

City of New York (City)  
Joint Utilities<sup>1</sup> (JU)  
Distributed Sun, LLC (DSUN)  
Clean Energy Parties<sup>2</sup> (CEP)  
New York Power Authority (NYPA)  
New York State Office of General Services (OGS)  
New York State Utility Intervention Unit (UIU)

I. General CommentsCity

The City conceptually supports the implementation of the CBC because it is a reasonable approach to supporting City and State policy objectives while achieving rate design principles of gradualism, cost-causation and customer orientation. The City believes that the CBC should not apply until one year after the Commission approves a final CBC structure, and any future changes to the CBC must be predictable and gradual. Also, the City argues that LMI customers and affordable housing projects should be exempt from the CBC. Lastly, the City suggests that Staff should conduct further analysis of the economic impacts associated with different delivery rates, compensation methodologies, and DER business models to properly balance impacts on non-participating customers (if any) with maintaining robust DER deployment.

In reply comments, the City cautions that imprudent implementation of the CBC could inhibit the decarbonization efforts of increased solar generation deployment. The City recommends the CBC proposed by Staff and further argues for

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<sup>1</sup> Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

<sup>2</sup> Solar Energy Industries Association, the Alliance for Clean Energy New York, Coalition for Community Solar Access, the Natural Resources Defense Council, the New York Solar Energy Industries Association, and Vote Solar.

implementation in a statewide proceeding, rather than as a result of individual rate cases. The City contends that statewide proceedings can attract a wider range of stakeholder participation, in addition to offering advantages of statewide ratemaking consistency not possible when rates are developed in separate rate case proceedings.

#### CEP

The CEP is concerned about the uncertainty and scope of the CBC, and believes it is loosely defined in terms of what costs could be included in such a charge in the future, as well as the process by which the charge would be updated by individual utilities. The CBC should only include costs related to utility low income programs. The customers that would be subject to the CBC are already making significant financial investments in support of New York's clean energy goals and it would be unreasonable to require them to pay public benefit charges for programs designed to meet these goals. The Commission should outline a clear process for updating the CBC that will allow adjustments to the CBC levels in a statewide process without the need to litigate this issue in each utility rate case. The CEP requests that any changes to the CBC during the bridge rate period be proposed in a statewide process outside of individual utility rate cases.

The Commission should reject the Staff proposal to directly assign the costs of new meters to solar customers. Costs associated with new customer meters should be collected through the customer charge on an average customer basis, consistent with historic practice. The Commission should reject movement toward three-part rates for mass market customers in future phases of this proceeding. The Commission should order greater data transparency in later phases of this proceeding to ensure all parties have access to metering data necessary to evaluate rate options that will succeed bridge rates. To provide a level playing field and transparency, CEP asks the Commission to order anonymous data access protocols be established to ensure all parties have access to AMI data in future phases of this proceeding.

If the Commission adopts the CBC, it should be assessed based on the AC size of the installed system, not DC as proposed by Staff. The Commission should order that utilities

exempt any commercial customer on demand rates from paying the CBC. The Commission should order the JU to update TOU rates. The current TOU rates in New York are undersubscribed and very poorly designed. The CEP recommends the JU update these rates to include a much shorter on peak time period that would allow customers to employ behavior and technological changes to reduce peak demands.

Further, the CEP is generally supportive of a CBC to recover costs for specific public benefit programs; however, the structure and details of this charge are critically important in assessing how it will affect the solar industry. The CEP finds that for all six utilities, the CBC levels proposed by Staff would increase total annual bills by 20%. The CEP believes that Staff's proposal also introduces additional uncertainty into future project economics, which will instill reluctance from customers to invest in solar. Additionally, the CEP disagrees with the inclusion of several cost categories into the CBC.

The CEP recommends the Commission limit the CBC cost categories to only include costs associated with the Low-Income Program. The CEP recommends the Commission cap the CBC charge at a fixed amount, potentially \$0.50/kW per month, to provide certainty on the ceiling of this potential charge for the bridge rate period and would only remain active during the bridge rate period and would be revisited when Staff considers the replacement to the bridge rates. The CEP recommends the Commission allow utilities to update the costs related to the Low-Income Programs. These updates should occur on an annual basis and allow participation, review, discovery, and response from stakeholders. The CEP also recommends the Commission disallow any foundational changes to the CBC for the bridge rate period.

The CEP argue that utilities are in the process of installing new metering infrastructure either currently or soon. By charging NEM customers directly for new meters, a utility would over-collect metering costs from that customer. The CEP recommends that costs for all new meters be collected in the customer charge on an average basis, regardless of if any NEM technology has been installed or not.

The CEP believes that the three-part rates for mass market customers are not cost-based, and the Commission should reject them. Further, the three-part rates are an antiquated

electric rate design and should not be considered for mass market customers. The CEP states that AMI will allow utilities to implement much more sophisticated and advanced rate designs, such as a time-of-use with critical peak price or a variable peak price. The CEP contend that the imposition of this type rate design has been very harmful to solar markets in other states.

The CEP opposes Staff's view that a large-scale cost shift existed between DG and non-DG customers. The CEP suggests that the alleged "cost shift" cannot be considered without also considering the numerous benefits that distributed generation provides to the grid, which are fundamentally different from embedded utility costs. Finally, the CEP recommends that any commercial customer on demand rates, which for most utilities is any customer with greater than 10kW of peak demand, be exempt from paying the CBC.

On May 7, 2020, the CEP filed with the Commission a Request to Delay Phase One NEM Decision Until December 31, 2022 due to Severe Industry Disruption caused by COVID-19. The CEP details the negative effects on the DG industry being caused by the COVID-10 pandemic, including a new DG business decline of up to 75%, the New York solar industry losing more than 9,000 jobs in June 2020, a 100% reduction in DG installations for the second quarter of 2020 for all market segments, and a likely decline of 48% for 2020 New York DG installation activity.

#### JU

The JU supports an expedited transition to cost-based rate designs that require mass market DER customers to more fairly contribute to the variety of utility programs, offerings, and investments that benefit these customers. The JU argue that the proposed CBC charge should be modified to both accomplish this goal and create a more sustainable platform for attaining the State's clean energy goals. The JU urge the Commission to retain volumetric crediting for existing TOU rates because monetary crediting exacerbates the very challenge this proceeding is seeking to resolve.

The JU states that traditional NEM pricing does not conform to the Commission's rate design principles and has long outlived its original purpose of incentivizing early adopters of a nascent technology. The JU believes that NEM perpetuates the



unwarranted shifting of cost burdens among customer groups and does not create efficient price signals for customer DER adoption or even accurately reflect the value provided by DER. The JU requests relief from this mounting burden and urge the Commission to take decisive action to end this inefficient rate design as soon as practicable.

The JU believes that the CBC should recover both public benefit program costs and other costs incurred by utilities to serve customers and the public. Further, the CBC does not capture both types of such costs will simply further extend the unfair shifting of cost burdens that the Commission sought to end when it began this process in 2015. The JU argue that the proposes approach will not align compensation with the value provided. The JU recommend phasing in a modified CBC over a period no longer than five years to appropriately capture these costs. The JU argue that rate design should send appropriate price signals that encourage customers to use and generate electricity in ways that benefit the system and thereby benefit all customers. Direct incentives should be provided for technologies that need support. The JU oppose the Whitepaper's proposal to grandfather customers under certain rate designs, but supports retaining volumetric crediting for all NEM customers with volumetric delivery rates.

The JU state that bills for non-participants will increase without a timely NEM successor. The JU believes that combining monetary crediting with existing volumetric TOU rates may exacerbate NEM cost shifts for non-participating customers. The JU state that the use of monetary crediting with TOU delivery rates can encourage oversized installations to maximize monetary credits and, as a result, increase bill impacts for non-participating customers. The JU argue that a better rate design approach would establish demand-based rates for delivery service and time-varying rates for supply.

The JU opposes CEP recommendations to limit the CBC solely to costs related to low-income programs. The JU believe that such a narrow restriction would continue to exempt NEM customers from fairly contributing to the recovery of all other utility costs. The JU agree with the City that LMI customers should not face limited participation in solar deployment. The JU emphasizes that providing technology-agnostic, clean energy market support through transparent funding mechanisms such as

the NY SUN program would improve access within the LMI community. The JU argues that explicit incentives provided through programs external to rate design would buy down the cost of clean energy projects, reducing the project costs that would need to be covered under an ongoing contract with the developer.

#### UIU

UIU supports Staff's concept of a CBC charge based on the size of the solar system. However, to minimize cost shifts that will likely benefit these customers, UIU recommends that this charge should only have a duration of ten years, after which participating customers should then be required to participate in rate design rules. UIU supports the longstanding principle that a gradual approach to help continue public benefits is in the best interest to all consumers.

UIU suggests that CBC charges applied to new onsite solar projects, at a minimum, include the costs associated with all public benefit programs as mentioned in the Whitepaper. UIU also recommends that the Commission consider the JU's recommendations the CBC charges be increased to a level that avoids unfair cost burdens to non-participants.

UIU understands that there are many elements besides cost of service methodologies that are essential to an informed discussion on rate design. Staff does not identify how to handle revenue neutral rate design when some utilities already have multiple residential service classes that are not designed revenue neutral to each other. Cost assignment in utility ratemaking is not standardized statewide. If the amount of money allocated to a service classification is not correct, it is unlikely that a rate design will send a correct price signal. A standardized approach for the application of revenue neutrality in the design of future rates needs to be defined among NY utilities.

While New York utilities have not yet fully implemented AMI, Staff does not identify how utility load research programs should be setup to handle future rate design discussions and analysis. Moving away from traditional rate design requires a redefinition of each NY utility load research program. Additional load research data is essential to developing statistically reliable and meaningful rate design for all mass market customers and may take time to obtain.

## II. Principles of Rate Design

### DSUN

DSUN concurs that Staff was diligent in considering rate design principles in its proposal for new tariffs for mass-market and on-site commercial projects less than 750 kW.

### City

The City argues that a continuation of familiar NEM policies will maintain market certainty for vendors and customers. Consequently, the City favors the customer benefit charge over alternative successor tariffs, claiming it supports preferable policy outcomes by avoiding fundamental changes to current net energy metering operations that could diminish market certainty. The City also expresses concerns about the timeline for the development of a successor tariff. At least one year of AMI data are required to develop an applicable successor tariff and the City contends that it is unlikely that sufficient information will be collected to design and implement a tariff within the timeframe proposed by Staff.

Instead, the City recommends designating the CBC as the successor tariff, or failing that, calls for it to function as an interim tariff for a longer period than Staff proposes. Additionally, the City notes that many details of the CBC remain intentionally incomplete in Staff's proposal to allow for stakeholder input. The City recommends delaying implementation of NEM successor tariffs for a year after the tariff details are finalized.

### JU

JU argues that the development of cost-based rates and transparent incentive programs is the most effective way to promote viable, sustainable, and cost-effective technologies and resources, and concurs that the CBC construct put forward in the Whitepaper provides an opportunity for such a transition.

In their reply comments, the JU allege that approaches proposed by the City, CEP, and DSUN will only further delay a transition to the equitable rate design goal the Commission adopted in 2015. The JU maintains that the present proceeding already supports market certainty in adherence to timelines, the transparency achieved in the current process to alter NEM, and

in the development of the CBC. The JU view the modified CBC as a reasonable transition mechanism between current NEM policy and the more equitable, cost-based rate designs sought by the Commission.

### III. Delivery Rate and Compensation Options

#### City

The City finds that the CBC rate estimated in the whitepaper is accurate, and, assuming that the proposed rate is sound, would allow projects to be economically viable. However, the City is concerned that any increases to the CBC will affect the economic viability of solar generation projects and hamper future adoption. Moreover, the City notes that Staff presented its economic evaluation of rooftop solar installation without identifying which financing and ownership situations were considered, making it difficult to assess the effects of the CBC on various solar business models. The City requests that Staff include in its economic analysis the entire range of solar business models to identify any disparate effects. The City also argues that LMI customers and affordable housing residents should be exempt from the CBC.

In reply comments, the City endorses the Staff proposal as reasonable, balanced, and based on fundamental rate design principles. In particular, the City supports its focus on reversing only those cost shifts associated with avoided contributions to public benefit programs, and generally commends the Staff proposal for its gradualist approach and concern for effective policy outcomes.

While the City agrees with the recommendation by CEP for future consideration of CBC issues in a generic statewide proceeding, it rejects the CBC level proposals by both CEP and the JU. In endorsing the Staff proposal, the City hopes to avoid any rate shock caused by abrupt increases to customer costs, in addition to promoting adequate customer understanding to ease the departure from volumetric mass-market rates represented by the new CBC charge.

#### JU

The JU argues that configuring rate designs to promote the adoption of specific energy technologies is inconsistent

with the fundamental rate design principles of technology neutrality, cost causation, and transparency. Similarly, the JU contends that the economic viability of any particular technology should not be used as criterion for reviewing the practicality and reasonableness of a rate design. Rather, the JU insists that assessing the effects of any rate on a projects economic viability and financing should be premised on whether the technology in question is economic to install and operate under cost-based rate designs.

The JU argues that the future use of rate design as an incentive mechanism to promote solar installations and other NEM-eligible technologies will continue to expose nonparticipating customers to increased costs, perpetuate current economic inefficiencies, and impede the State from effectively responding to inevitable future technology improvements and innovations.

The JU disagrees with NYPA's recommendation to allow BTM resources to generate RECs, and note that the Commission previously rejected this arrangement in 2017. If the Commission reverses its decision, the option to generate and retain RECs should be restricted to a one-time, irrevocable election.

#### NYPA

NYPA recommends Tier 1 renewable energy credits be made available for behind-the-meter projects ineligible for value stack compensation to ensure complete valuation for the greenhouse gas emissions reductions and other environmental benefits provided by such installations. NYPA also advocates making available a greater variety of compensation options for projects with net injections to the grid. It notes that customers that forgo the Environmental Value for the opportunity in order to participate the voluntary market lose this this form of reimbursement and should instead be permitted to choose between value stack compensation and Tier 1 RECs. Finally, NYPA argues for a consistent application of proposed delivery rate and compensation options to projects that self-consume and net-inject energy in order to better support DER projects. NYPA also suggests that administrative burdens could be reduced if the Commission permitted aggregation of smaller projects in a managed REC project portfolio.

OGS

OGS concurs with NYPA and generally agrees that the Staff proposal would advance State policy objectives. OGS contends that behind-the-meter projects are not compensated equitably as are other projects, and agrees with NYPA that these barriers should be eliminated. It agrees that all BTM projects should be eligible for Value Stack compensation including Tier 1 RECs, and requests that Staff address this matter so these resources can contribute fully to State energy policy goals. According to OGS, the current structure effectively forecloses the full use of all available opportunities for DER deployment.

OGS argues that compensation for distributed generation should be based solely on a DER's value to the grid and contends that compensation of DER output with the Environmental Value could promote the development of DER, even if the customer benefit contribution is deducted. OGS contends that this would be especially beneficial, as the development of BTM distributed resources generally avoids land and customer acquisition costs associated with other projects.

IV. Delivery Rate GrandfatheringCEP

CEP states that the CBC proposed by Staff are significant and the substantial reduction in bill savings will reduce customer incentives to install solar. While solar customers may generally have lower energy bills, CEP disputes the extent of this cost shift, noting also that without access to the data used in the development of the Staff proposal, it is unable to support it. Nevertheless, the CEP allege that the avoided totals costs is likely minimal, considering the number of solar customers in New York. The CEP continues to advocate for other rate options as more effective ways to achieve policy goals with cost-reflective ratemaking, particularly time-of-use rates paired with critical peak pricing or peak-time rebates.

In its reply comments, the CEP reiterated their argument that not allowing grandfathering will cause market uncertainty for solar installation customers and vendors. According to the CEP, the JU consistently support rate options like high fixed charges and demand charges that diminish customer interest in residential solar installations, an

unreasonable approach that could ultimately inhibit the solar industry in New York State and forestall achievement of solar installation and climate policy goals. The CEP restated their prior support for time-of-use rates coupled with critical peak pricing or variable peak pricing, which it argues provide better price signals than demand-based rates and can achieve greater demand reduction.

#### City

City maintains that NEM customers should be allowed to remain on a delivery option for a significant period of time to capture the benefits of on-site DER. It supports the proposal by Staff to allow projects into standard or TOU rates with the CBC for twenty years, arguing that altering rates of an existing project would undermine its present economic viability and contribute to future uncertainty.

#### DSUN

DSUN proposes allowing customers to remain on standard or TOU delivery rates for a 20-year period, though its primary argument is that this will allow a fuller understanding of the economic effects of renewable energy deployment.

#### JU

JU opposes the exemption from rate changes recommended by Staff, the City, and DSUN. They argue that the Commission should not insulate customers from reasonable rate design changes that reflect maturing markets, shifting economic situations, and evolving regulatory priorities. The JU predicts that allowing customers to remain on obsolete rates would create a complex and confusing regulatory environment that contravenes well-established Commission policies that hold that customers are subject to changes in both rates and rate designs.

The JU argue in reply comments that unrestricted exemptions recommended by the CEP would result in customers artificially avoiding the effects of evolving rates, and add that they see no justification in allowing rational rate design changes that reflect market maturation and other fundamental economic effects.

V. Optional Standby RatesDSUN

DSUN has not analyzed the financial effects of the CBC on internal rate of return for customers who choose the optional standby rates. However, because the rate is optional, DSUN does not object to imposing the CBC to these customers, aside from the problem of future rate increases noted by DSUN in response number six.

JU

JU argue that draft standby rates filed by the utilities in September 2019 will limit cost shifts from standby rate customers and the need for a CBC to apply this class, as most delivery costs will be recovered through demand charges. However, the JU suggest that a minimal CBC may still be appropriate to capture costs not recovered through demand charges.

VI. Reduced CBC for Value StackCEP

CEP advises that the CBC for customers opting into Value Stack compensation might vary according to utility. For example, a discounted CBC might be appropriate for utilities that have fully exhausted their MTC or Community Credit allocations.

City

City notes that the data used to estimate self-consumed energy for Value Stack projects was not included in the Whitepaper, meaning that stakeholders were unable to review Staff's calculations, or to propose alternative discounts. The City suggests that more information is needed to assess the degree of the CBC's application - if it applies at all - to customers choosing value stack compensation. Further, the City notes that the CBC is likely to have economic effects on value stack projects and that no analysis of these outcomes appears to have been undertaken. The City requests that the Commission ensure that the CBC will not have any undue effect on value stack projects before it is implemented.



JU

JU notes that because Con Edison's mass market customers opting into the Value Stack are eligible for a \$0.12/kWh community credit, these customers effectively receive as much compensation as they would have received under traditional NEM.

VII. Demand-Metered CustomersCEP

CEP objects to the proposal by Staff to move to demand-based rates for mass-market customers in later phases of this proceeding. Not only are demand-based rates for mass-market customers not cost reflective according to the CEP, but they are likely to discourage investment in most distributed resources and decrease access to energy efficiency measures for low and moderate-income customer. The CEP alleges that the primary function of such demand-based rates is to stabilize utility revenues.

City

The City argues that there is no reason to apply the CBC to these customers.

DSUN

DSUN recommends that no CBC be imposed on commercial project under 750 kW, noting that its own analysis indicates that such charges in the NYSEG, RG&E, and Niagara Mohawk service territories will render such projects economically infeasible, even at reduced rates.

JU

The JU agree that demand-metered customers should not be subject to the CBC, noting that properly designed demand charges should inherently reflect customer benefit costs. However, if demand charges do not adhere to the rate design principle of cost causation in practice, implementation of a CBC may be necessary to reflect any remaining delivery and customer benefits costs not otherwise captured by the demand charge structure.

In its reply comments, the JU argues that it is inappropriate to preclude demand charges in the absence of a successor rate, noting that these are some of the more cost-effective rate designs already in use for commercial customers. The JU urge the Commission to reject this proposal to eliminate three-part rates.

### VIII. Non-Solar Technologies

#### DSUN

DSUN supports the calculation and application of a CBC using a technology-neutral approach to achieve appropriate policy outcomes.

#### JU

The JU recommends that the CBC should be applied to all NEM-eligible technologies, arguing that without this charge, customers with such measures would avoid paying for customer benefit programs. The adoption by the Commission of a timely transition to demand-based rate designs for delivery service could minimize the administrative complexities related to devising various CBC for specific technologies. Such a technology-neutral approach aligns with the Commission's long-established rate design principles.

### IX. CBC Changes

#### CEP

CEP maintains that an increase to the CBC will impose extremely high fixed charges on solar customers, which would almost double the CBC in some service territories. Noting that the JU offers no justification for such increases, the CEP argues that they go beyond the original purpose to recover cost for public benefit programs and that they would ultimately discourage continued investment in residential solar installations.

#### The City

The City states that if changes to the CBC are necessary, they should be gradual and predictable to achieve a reasonable balance between effects on nonparticipating customers

and the achievement of policy objectives. It declines to recommend a specific policy to achieve this but supports advance notice of such changes to customer to allow adequate time for decisions about projects with extended development and economic payoff schedules.

#### DSUN

DSUN expresses concern over the effects of unrestricted increases to the CBC, and recommends that limits on annual increases be established. It argues that this will permit the development of financial models for investors that accurately describe future costs of the CBC and their effects on internal rate of return.

#### NYPA

NYPA advocates for an exemption from the CBC for NYPA economic development customers, remarking that the Commission has previously concluded that NYPA program customers should be excluded from such charges that support the economic development objectives of these programs.

#### JU

The JU recommends a transitional period beginning on January 1<sup>st</sup>, 2021, and ending either within five years of that date, or one year after sufficient interval data are available for each individual utility to suspend the CBC and implement a demand-based NEM successor rate. Once cost-reflective, demand-based delivery rates are developed in a NEM successor rate, the CBC would become unnecessary. The JU add that a NEM successor rate should reflect all fixed costs in fixed charges and all demand-based costs in demand charges. However, the JU argue that while the CBC is in place during this bridge period, it should be increased to reflect fixed and demand-based costs previously recovered from mass-market customers through volumetric rates for mass-market customers.

## X. Transition to Cost-Reflective Rates

### DSUN

DSUN supports the transition to more cost-reflective electric delivery and supply rates, both as a default and as an option.

### JU

The JU urges the Commission to begin this transition without delay and without exemptive provisions that would insulate certain customers from rate design changes. The JU suggests that a bridge period may also be needed to allow time for needed historical interval meter data to become available to inform customer decision-making for adopting DER under demand-based rates. The JU notes that some of the Commission's thresholds related to NEM mass market capacity targets have been met or exceeded and further delay only means that the bill impacts of NEM on non-participating customers will continue to grow.

The JU proposes the following transitional approach based on the CBC construct reflected in the Whitepaper. The JU support the CBC construct as an appropriate approach for the transition to cost-based rates, but also agrees that the Whitepaper's initial CBC does not reflect any remaining costs that utilities incur to serve NEM customers and the public that are collected volumetrically and currently avoided by mass market NEM customers. The JU argues that on average, the recommended CBC fails to collect approximately 82 percent of the residential cost shift identified in the Whitepaper. Therefore, the JU recommends a higher initial CBC and gradual increases in the CBC.

The JU suggests that given the need to transition to more cost-based rates in a timely manner, the transition to the full CBC should occur over a period of no more than five years, and the Commission should increase the CBC in equal annual increments to implement the transition. The JU urges the Commission to adopt a transitional approach that will move toward more cost-based rates in no more than five years. The JU states that this illustrative CBC phase-in should be considered the minimum appropriate levels for the CBC. The NEM cost shifts and resulting CBCs for each utility should be more thoroughly

examined and this review is likely to result in CBCs greater than those in the Whitepaper, according to the JU.

The JU states that to the extent that the elimination of subsidies inherent in the current rate structure creates the need for additional incentives for NEM-eligible technologies, NYSERDA's clean energy programs are the appropriate sources of additional funding. If funding beyond NYSERDA becomes necessary, the JU suggest that the Commission could consider the establishment of a non-bypassable charge or some other equitable mechanism for customers to fund the development of clean energy resources in a transparent manner.

## XI. Outreach and Education

### The City

The City states that the best approach to familiarizing customers with new rate design options is to focus on the tangible outcomes of different rates. The City suggests that bill inserts should include easy to follow comparisons of customer consumption and (assuming AMI rollout is complete) customer demand against different rate options, and examples of shifting consumption away from particular time intervals. The City further cautions against relying wholly or primarily on rate calculators because calculators that do not provide accurate results would further mystify and discourage uptake of new rate design options.

### DSUN

DSUN supports any tool that provides clarity in the calculation of the CBC and future increases. DSUN supports further examination of the cost shift and avoidance of public benefit charges for commercial projects under 750 kW in future Rate Design Working Group activities.

### JU

The JU agrees with the importance of these efforts and tools and widescale outreach and education are an essential requirement for implementing new rate designs. Additionally, the JU suggests that utility-enabled tools and materials should supplement outreach and education activities. These include: (1) the use of utility web portals, (2) text and email alerts

regarding peak hours, (3) increased use of energy efficiency measures including programmable Wi-Fi-enabled thermostats, weatherization, and increased appliance efficiency, (4) an increased ability by the utility to control customer load, and (5) other technologies including battery energy storage.

NYPA

NYPA supports the proposed development of an online rate calculator to use as an outreach and education tool to teach customers about the new rate design. Further, NYPA argues that the calculator should allow customers to compare what they would have paid for the prior year under various rate designs so they can learn which rate is beneficial.