STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

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

ORDER ON STANDBY AND BUYBACK SERVICE RATE DESIGN AND ESTABLISHING OPTIONAL DEMAND-BASED RATES

Issued and Effective: May 16, 2019

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APPENDIX 1: Standby Service Daily As-Used Demand Elements at NYS Utilities

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on May 16, 2019

COMMISSIONERS PRESENT:

John B. Rhodes, Chair
Gregg C. Sayre
Diane X. Burman, concurring
James S. Alesi

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

ORDER ON STANDBY AND BUYBACK SERVICE RATE DESIGN AND ESTABLISHING OPTIONAL DEMAND-BASED RATES

(Issued and Effective May 16, 2019)

BY THE COMMISSION:

INTRODUCTION

Through the issuance of the VDER Transition Order in March 2017, the Public Service Commission (Commission) began the transition of compensation for Distributed Energy Resources (DERs) from Net Energy Metering (NEM) to methodologies that reflect the actual value provided by those resources to the grid and to society and that enable a distributed, transactive, and integrated electric system.[1] The VDER Transition Order also contemplated the development of methodologies to more accurately reflect the costs that DERs impose on the grid. For example, customers with DERs reduce distribution grid usage but continue

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[1] Case 15-E-0751, et al., 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).

to rely on the availability of the grid, such that if their bills decrease to reflect their reduced usage but have no element that reflects the continued need for grid availability, costs caused by those customers would be shifted to other ratepayers. Selling excess generation from a DER directly to the utility may impose similar grid availability costs. In general, the rates intended to recover appropriate costs for customers in these categories are Standby Service rates and Buyback Service rates.

On December 12, 2018, Department of Public Service Staff (Staff) filed the Whitepaper on Standby and Buyback Service Rate Design and Residential Voluntary Demand Rates (the Staff Whitepaper). The Staff Whitepaper reflects a final version of the Staff Standby/Buyback Whitepaper Draft Outline filed on February 7, 2018 and represents the culmination of an extensive stakeholder process to consider refinements to the Standby and Buyback Service rates and related policies.

The Staff Whitepaper generally recommends: expanding the availability of Standby Service to include opt-in eligibility for all residential and small commercial (mass market) customers; requiring more granularity in the As-Used Demand Charges through Off-Peak, On-Peak, and Super-Peak charge components; requiring utilities to use an Allocated Embedded Cost of Service (ACOS) methodology to develop standby rates; expanding the multi-party campus offset tariff to statewide application; improving the design and administration of Buyback Service tariffs; and, addressing the application of grid access demand charges for energy storage systems.

This Order directs significant improvements and modifications to the Standby and Buyback Service rates currently in place at New York's investor-owned electric utilities[2] to more accurately reflect costs and benefits and to ensure that those rates are available to all interested ratepayers.[3] Among other things, the determinations in this Order: (1) expand the availability of demand rates based on the Commission's Standby Service rate design principles, by requiring opt-in eligibility for all customers to a demand-based rate option, irrespective of whether customers have on-site DERs, thereby enabling all customers to potentially benefit from a rate design that produces an improved alignment between customers' contributions to system costs and the rates they pay; (2) strengthen the price signals provided by Standby Service rates through requiring more granularity in the As-Used Demand Charges by using Off-Peak, On-Peak, and Super-Peak charge components; (3) improve the accuracy and consistency of cost allocations underlying the Standby Service rates through the required development by each utility of an ACOS methodology, which will provide parameters for periodic review of the allocations of costs between a local basis or a shared basis; (4) expand the geographic availability

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[2] The investor-owned electric utilities include 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 (Niagara Mohawk), Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas and Electric Corporation (RG&E).

[3] It should be noted that the Standby Service rate designs discussed herein apply to <u>delivery</u> service rates; they do not apply to the <u>supply</u> component of a standby customer's requirements. Standby customers may elect to receive energy supply from the utility or purchase it from another entity in the competitive market. Where they elect to receive service from the utility, rates for that supply service are independent from Standby Service rates and based on the applicable tariff provisions regarding supply service to customers with their characteristics.

of multi-party campus offset tariffs that allow the load of multiple customers in multiple buildings to be offset by a common generator; (5) improve the design and administration of Buyback Service tariffs to eliminate or reduce barriers to deployment of DERs; and, (6) clarify the application of grid access demand charges for energy storage systems.

With the refinements adopted in this Order, customers currently served under Standby Service and Buyback Service rates will have an increased ability to manage their bills and those bills will more accurately reflect the impacts on the system associated with their usage. Finally, more customers will have the opportunity to take advantage of these more precise price signals through the expanded availability of Standby Service rates as optional rates under this Order.

NOTICE OF PROPOSED RULE MAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rulemaking regarding the Staff Whitepaper was published in the State Register on December 26, 2018 [SAPA No. 15-E-0751SP18]. In addition, a Notice Soliciting Comments on the Staff Whitepaper was issued on December 21, 2018.[4] The time for submission of comments pursuant to the notices expired on February 25, 2019. The comments received are summarized and addressed in the body of this Order where relevant.

[4] The Secretary's Notice also requested comments on the Staff Whitepaper Regarding Future Value Stack Compensation, Including for Avoided Distribution Costs, filed on December 12, 2018, and the Staff Whitepaper Regarding Capacity Value Compensation, filed on December 14, 2018. Those matters were addressed in the Commission's Order Regarding Value Stack Compensation, issued April 18, 2019 in Case 15-E-0751.

LEGAL AUTHORITY

As described in the VDER Transition Order, the Commission has the authority to direct the treatment of DERs by electric corporations pursuant to, inter alia Public Service Law (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

I. Standby Service Rates

A. Background

In October 2001, the Commission issued Guidelines for the design of Standby Service rates.[5] The Guidelines explained that service to customers with on-site generation is sufficiently different in terms of costs imposed on the utility system, as compared to service to customers without on-site generation, to justify different treatment. The Guidelines described cost-based rate design principles that should be used for developing rates for Standby Service, including general avoidance of cost recovery based on volume (in kWh) of energy consumed.

The Guidelines explained that Standby Service rates should be designed to recover distribution system delivery costs through a combination of class-specific Contract Demand Charges and Daily As-Used Demand Charges, in addition to Customer Charges fixed by service class. The Contract Demand Charge would be designed to recover the costs of "local" facilities, that is, facilities that are closer to a customer's site and

[5] Case 99-E-1470, Rates, Terms and Conditions for the Provision of Electric Standby Service, Opinion No. 01-4 (issued October 26, 2001).

were put in place primarily to serve the individual customer. The Contract Demand Charges are fixed for each customer based on the customer's maximum demand. The Guidelines further stated that delivery system facilities located farther from customer sites should be considered "shared" facilities, the costs of which would be recovered in a manner that recognizes the customers' overall demand coincidence with that of the broader service classification, through Daily As-Used Demand Charges, calculated based on the customer's actual peak demand during the established system peak period each day.

The application of the Contract Demand Charge and the allocation of revenues between the Contract Demand Charge and the Daily As-Used Demand Charge have been the subject of substantial debate. In general, the revenue allocations by service classification, currently based on the negotiated outcome of proceedings in 2002 and 2003, are referred to as the Standby Matrices.[6]

Standby Service generally applies to two types of customers. First, Standby Service applies to customers that normally fully supply their own power through on-site generation but maintain a connection to the electric grid for service during generator failure or maintenance. Second, Standby Service applies to customers that supply part of their own power through on-site generation but frequently supplement it with

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[6] These rates were implemented for Con Edison and O&R on July 29, 2003 in Cases 02-E-0780 and 02-E-0781 respectively; for NYSEG on July 30, 2003 in Case 02-E-0779; for Central Hudson on December 4, 2003 in Case 02-E-1108; and, for Niagara Mohawk on June 21, 2002. Niagara Mohawk's Standby Matrix was recently modified in Case 17-E-0238, as described in greater detail later in this Order. RG&E uses a methodology based on marginal costs marked up to achieve revenue requirement targets, implemented on July 29, 2003 in Case 02-E-0551.

electricity supplied through the electric grid. In general, customers with on-site generation are required to take Standby Service unless (a) the on-site generation qualifies for technology- and size-based exemptions established in Commission orders,[7] or (b) the on-site generation has a capacity of less than 15% of the customer's maximum demand. Similarly, customers with qualifying on-site generation are required to take Buyback Service if their on-site generator will inject electricity into the electric grid[8] and is not eligible for NEM or the Value Stack Tariff.[9] Under Buyback Service, customers are paid for energy and capacity, based on wholesale prices for energy and capacity in the New York Independent System Operator, Inc. (NYISO)

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[7] Case 14-E-0488, Continuation of Standby Rate Exemptions, Order Continuing and Expanding the Standby Rate Exemption (issued April 20, 2015). Exemptions are available for: (a) customers who exclusively use fuel cell, wind, solar thermal, solar photovoltaics, sustainably-managed biomass, tidal, geothermal, and/or methane waste generation resources for on-site generation; (b) customers who use combined heat and power (CHP) generators of 1 MW or less in size meeting certain efficiency standards; and (c) customers who use CHP generators between 1 MW and 15 MW of size meeting certain efficiency standards, where such generators were installed between April 20, 2015 and May 31, 2019.

[8] Utilities are required to offer Buyback Service to "Qualifying Facilities" as defined in 18 CFR 292 and to "alternate energy facilities," "co-generation facilities," and "small hydro facilities" under PSL §§ 2 and 66-c. Utilities are not required to purchase net electricity injections from other sources.

[9] While the technologies eligible for NEM and the Value Stack Tariff are within the bounds of "alternate energy facilities," "co-generation facilities," and "small hydro facilities" under PSL §2, PSL §66-j and the VDER Transition Order further specify the rates which utilities must pay for eligible net electricity injections under the applicable Net Metering and Value Stack Riders.

market, by the utility for their net injections of electricity into the grid.[10]

II. Designing Standby Service Rates for Mass Market Customers

A. Background

While Standby Service rates traditionally apply primarily to large customers with demand metering, each of the utilities, other than Con Edison and O&R, have Standby Service rates available for mass market customers, even though these customers are not billed based on demand. In the case of charges for mass market Standby Service, the utilities still use elements that are intended to provide recovery similar to the Customer Charge, Contract Demand Charge, and Daily As-Used Demand Charge rate components for demand-billed Standby customers. However, the mass market standby rates are based on volumetric electric usage in kWh, instead of on demand in kW. The flat monthly customer charge design is similar between the large customer classes and the mass market customer classes. For mass market customers, the Contract Demand Charge revenue requirement is also collected through a flat monthly charge that does not vary between customers based on their maximum potential or actual demand. The Daily As-Used Demand Charge revenue requirement is collected through a monthly volumetric per-kWh charge, instead of being based on the sum of actual daily demands during on-peak periods.

Notwithstanding the theoretical availability of Standby Service rates for mass market customers, such customers

[10] For energy injections under Buyback Service, the utility pays a rate based on the NYISO Location-Based Marginal Price (LBMP) at the time energy is produced. For capacity, the utility pays a rate that reflects the cost of Installed Capacity (ICAP) that it avoids having to purchase from the NYISO market during the NYISO peak hour as a result of the customer’s injections during that hour.

generally do not take service under standby rates due to the lack of an on-site generator, an exemption from Standby Service under NEM, or the availability of a mandatory small-customer exemption through May 31, 2019.[11] Further, small commercial demand-metered customers with a maximum demand below a specified level (e.g., 5kW for NYSEG customers and 10kW for customers served under Con Edison's Service Classification (SC) 9 tariff) are offered an exemption from standby rates, established because most customers of that type currently do not have the necessary interval metering. These small demand-metered customers may nonetheless elect to be billed under Standby Service rates if they pay the applicable meter upgrade and communications fees.

B. Staff Whitepaper Recommendations

With interval metering becoming much more widely available due to the rollout of Advanced Metering Infrastructure (AMI) throughout New York State,[12] mass market Standby Service

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[11] Case 14-E-0488, Standby Rate Exemptions, Order Continuing and Expanding the Standby Rate Exemption (issued April 20, 2015). A concurrent order extends the standby rate exemptions through May 31, 2021. Case 19-E-0079, Continuation of Standby Rate Exemptions, Order Continuing Standby Rate Exemptions (issued May 16, 2019). In general, mass market customers meeting the eligibility criteria for an exemption are not permitted to opt-in to Standby Service; the one exception to this rule is Niagara Mohawk, which does allow such customers to opt in and does not impose a limit on the number of customers that can opt in. Central Hudson, NYSEG, and RG&E each exempt up to 100, 250, and 150 non-NEM-eligible customers, respectively, from standby rates. Neither Con Edison nor O&R have implemented mass market standby rates or limits to the number of non-NEM-eligible customers exempt from standby rates.

[12] Each of the utilities other than Central Hudson either has a Commission-approved AMI rollout plan or has proposed such a plan for Commission consideration. While Central Hudson is not planning on rolling out AMI to its entire service territory, AMI meters and access to meter data are available to Central Hudson's mass market customers for a fee as part of the Insights+ Demonstration Project.

rates no longer need to be limited to flat fees and volumetric energy usage. Rather, rates for mass market Standby Service can be measured and billed on the basis of demand in the same manner as the Standby Service rates applicable to larger customers. As this meter data becomes available, mass market Standby Service rates could incorporate a similar design to the larger-customer Standby Service rates.

The Staff Whitepaper recommends that each of the utilities be directed to submit draft tariffs implementing redesigned mass market Standby Service rates to implement Contract Demand Charges based on individual customers' maximum demand and Daily As-Used Demand Charges based on daily maximum on-peak demands, to be offered in those areas where AMI is available. The Staff Whitepaper further recommends that such rates be designed on a revenue neutral basis to the otherwise applicable service class (OASC), using load research data currently available, and subject to revenue reconciliation within the Revenue Decoupling Mechanism (RDM) applicable to the OASC. The Staff Whitepaper also recommends that the utilities consider modifications to the electric supply rates applicable to mass market Standby Service customers taking full utility service, to align them with the electric supply rates applicable to large Standby Service customers. This recommendation recognizes that AMI data will allow the utilities to provide each customer with an actual Installed Capacity (ICAP) tag after one year of usage data is obtained, and therefore to provide supply charges based on a customer-specific ICAP tag and hourly energy usage at the NYISO's Locational Based Marginal Price (LBMP).

C. Comments

The Joint Utilities[13] support the introduction of demand-based rates for mass market customers because such rates will more accurately reflect cost causation and thus deliver efficient price signals to customers, which will lead to investment decisions that appropriately reflect grid impacts and support goals enunciated in the various Reforming the Energy Vision (REV) initiatives. The Joint Utilities recommend use of "simplified versions" of the demand-based rates applicable to larger customers, so that mass market customers can understand and reasonably respond to them. The Joint Utilities also suggest that hourly supply rates could be optional for mass market customers.

AEE Institute supports opt-in standby distribution rates for all mass market customers, regardless of whether the customer has on-site DER. AEE Institute also supports coupling opt-in standby rates with improved supply charges based on hourly NYISO LBMPs and capacity charges based on customer-specific ICAP tags. AEE Institute argues that cost increases to non-participating customers are not an inevitability, even while participating customers realize cost savings, because participating customers are likely to provide system-wide benefits, lowering investment needs in both the distribution and wholesale systems through changing their usage. Limiting availability of opt-in standby rates based on potential rate increase for non-participant customers, AEE Institute explains, would limit the benefit of the new rate through limiting participation and would skew the price signals sent to both participating and non-participating customers. Rather than providing rate relief to customers in an untargeted way

[13] Central Hudson, Con Edison, Niagara Mohawk, NYSEG, O&R, and RG&E.

regardless of customer need, AEE Institute recommends that the Commission use programs that target customers in need to provide relief in a systematic way.

The City of New York (City) submits that in the absence of any analyses of the potential impacts of the proposed rate changes on non-participating customers, the utilities should be required to perform a comprehensive analysis of the potential customer impacts of imposing Contract Demand Charges and Daily As-Used Demand Charges on mass market customers prior to implementing any rate design changes.

The Clean Energy Parties (CEP) strongly object to introducing optional demand rates for mass market customers through increasing the eligibility of standby rates. According to CEP, requiring demand charges for mass market customers would have long-term negative impacts on New York's stated policy goals of growing DERs because demand rates typically reduce the bill savings driven by investments in DERs. CEP submits that demand rates are much less effective at producing effective price signals for customers than time-varying rates, such as time-of-use rates or critical peak pricing. CEP also claims that demand rates for mass market customers are not cost-based, as individual customer demand from customers rarely drive system costs, even on the distribution system. According to CEP, the non-coincident demands of mass market customers rarely align with the class or system peak. Moreover, the large on-peak windows currently in place for standby rates in New York would result in customers being charged for noncoincident peak demand that is not driving local costs. CEP urges rejection of Staff's proposal to direct utilities to adopt optional demand rates for mass market customers through increasing the eligibility of standby rates.

D. Determination

The Commission recently stated, in its Energy Storage Order, that standby and buyback rates "are among the most theoretically pure rate designs available for aligning an individual customers' contribution to system costs with the rates such customers pay, thereby sending accurate price signals to those customers."[14] Given the clear superiority of these rates in sending accurate price signals to customers, the Commission agrees that standby rates should be more widely available to customers, irrespective of whether customers have on-site generation. The Commission therefore directs each utility to submit a draft tariff implementing optional demand-based rates for mass market customers based on the standby rate design principles, as further refined as a result of this Order, by September 4, 2019. Such optional demand-based rates are to include Contract Demand charges based on individual customers' maximum demand and Daily As-Used Demand Charges based on daily maximum on-peak demands.

Since implementing these rates will require interval metering and rather than limiting the availability of these rates, utilities should provide such metering to individual customers as needed with associated incremental metering charges to recover the costs of such metering, until such time as customers' meters are replaced by AMI meters capable of registering demand. As recommended in the Staff Whitepaper, the optional demand-based rates are to be designed on a revenue neutral basis to the OASC using load research data currently available and subject to revenue reconciliation with the RDM applicable to the OASC. Further, as proposed in the Staff

[14] Case 18-E-0130, Energy Storage Deployment Program, Order Establishing Storage Goal and Deployment Policy (issued December 13, 2018) (Energy Storage Order), p. 15.

Whitepaper and supported by the AEE Institute and the Joint Utilities, the utilities shall also develop tariff provisions for supply rates, based on NYISO market prices, including hourly LBMP charges and customer-specific ICAP charges, to be included alongside the optional demand-based rates for full-service utility customers. In their respective implementation filings, the utilities should include plans on how they will specify ICAP charges for customers during their first year of interval data availability where metered individual ICAP tags may not yet be available.

Since the allocation of costs to the various rate components (e.g., Customer, Local, and Shared) of these new rates will be the subject of the ACOS filings and subsequent process described below, these draft tariffs shall be submitted by utilities along with and based upon those ACOS filings. It is expected that the Commission will consider the ACOS filings as well as the various rate design filings concurrently since the latter are very dependent upon the former. In addition, the Commission expects Staff to utilize the existing VDER Rate Design Working Group for further analysis and discussion and to provide the results for subsequent consideration by the Commission. Staff recently re-convened the Working Group to examine rate design issues across a range of technologies, using a prioritization framework that analyzes the suitability and sustainability of proposed rate designs across the breadth of various policy objectives. In addition to VDER rate design, for example, the Working Group will be considering the beneficial electrification proposals offered by National Grid,[15] as well as

[15] Case 17-E-0238, Niagara Mohawk Power Corporation d/b/a National Grid - Rates, Proposal of Niagara Mohawk for Voluntary Residential Rate Structure to Further Adoption of Beneficial Electrification Technologies (filed September 18, 2018).

those to be offered by O&R. Incorporating input from the Working Group process to inform these analyses will ensure that rate design principles are considered and applied consistently across utilities.

As the standby rate design principles are clearly superior to existing rates in aligning customers' rates to their contributions to system costs, providing this option to mass market customers as expeditiously as possible advances REV objectives of promoting more efficient use of energy, achieving deeper penetration of renewable energy resources and DERs, as well as promoting market solutions to achieve greater use of advanced energy management products. This decision does not require any customer to adopt such rates, nor does it determine that such rates should be applied to all customers with DERs. Furthermore, the improvements directed to Standby Service rates in this Order will ensure the mass market opt-in rates reflect actual system cost impacts.

III. Offering Standby Service Rates to All Customers

A. Background

As the Commission stated in its Energy Storage Order,[16] standby rates are designed to align individual customers' contribution to system costs with the rates such customers pay, thereby resulting in improved price signals for those customers. Other rate designs offer less accurate price signals due to recovery of multiple cost categories, with potentially different cost drivers, through a smaller number of charges and based on less applicable metrics. This issue arises particularly in mass market rate structures, where the monthly volumetric energy charge includes recovery of not only highly time-dependent, demand-related costs, but also a portion of fixed and customer-

[16] Case 18-E-0130, supra, Energy Storage Order, p. 15.

related costs. This is the case to the extent that the customer charge is designed to recover revenues that are less than the customer-related costs identified in the ECOS study. A rate design that provides a better match between cost causation and revenue recoveries than the existing rates generally should be made available to customers wherever possible.

However, any rate change necessarily results in bill impacts to individual customers, depending upon individual customers' billing determinants. This is true even if such rate changes are implemented on a revenue neutral basis. Since most or all participants in an opt-in rate will be those customers that will benefit from a rate option based on their current billing determinants (structural beneficiaries) or those who can change their usage to benefit from the rate option, bill impacts to non-participating customers could result. If the revenue impact due to the alternative rate option is reconciled to all the customers of the OASC, and customers that opt-in to the alternative rate pay less under that rate than the standard rate for the OASC, then customers paying the standard rate will pay more than they otherwise would have if there were no alternative rate option, due to RDM recovery of the shortfall. Even if the customers are appropriately paying less for service under a demand-based rate, it may not be reasonable to impose significant bill impacts on non-participating customers outside of a rate proceeding and without mitigation.

B. Staff Whitepaper Recommendations

The Staff Whitepaper asserts that all customers should have the option to be served under a rate option that contains the same elements as the Standby Service rate, and recommends that the utilities be directed to file tariff amendments expanding opt-in eligibility for all customers to select the applicable Standby Service rates in lieu of the customer's existing rate structure (subject to some limitations to address the bill impacts to non-participating customers).[17] This opt-in to standby rates would be effective for a period of not less than one year, to avoid customers switching between standby and standard rates to take advantage of seasonal rate fluctuations. At the same time, however, the Staff Whitepaper expresses the opinion that opt-in standby rates should be offered only if the bill impacts to non-participating customers remain manageable. The Staff Whitepaper recommends that in the case of Con Edison, NYSEG, and RG&E, these tariff amendments should be filed as part of each utility's next electric rate proceeding, which will allow bill impacts on non-participating customers to be carefully considered and mitigated. For implementation outside of general rate proceedings – in the case of Central Hudson, Niagara Mohawk, and O&R – the Staff Whitepaper recommends that opt-in standby rates should only be offered to customers as long as the potential bill impacts to non-participating customers fall below a certain percentage threshold. Stakeholders were requested to provide comments proposing a reasonable bill impact threshold.

C. Comments

NY-BEST supports Staff's recommendation that all customers be eligible to opt in to the standby rates and urges that customers be allowed to select any of the rate structures applicable to their service class.

The Joint Utilities express practical concerns with offering Standby Service rates to mass market customers only if "the bill impacts to nonparticipating customers fall below a

[17] These opt-in rates would not be "standby rates" under the traditional definition, since there is no onsite generation. However, given their structural similarity to standby rates, the Staff Whitepaper refers to them as opt-in standby rates.

certain percentage threshold." They request clarification as to whether the Staff Whitepaper contemplates (1) an ongoing evaluation of the bill impacts to other customers after the rate is offered and customers have opted into the new rate; or (2) utility evaluation of bill impacts to other customers, with a tariff filing only if the bill impacts are within a certain range.

The City submits that Staff's proposal to expand opt-in eligibility for all customers to take service under their otherwise-applicable Standby Service rates in lieu of their existing rate structure is premature and requires further development. According to the City, customers without DER (i.e., customers not changing their level of service) that switch to a Standby Service rate may benefit from lower payments, but potentially at the expense of customers not opting into the alternative rate structure. The City claims that such a migration of customers without a cost-justified basis could lead to higher rates to non-participants. It urges that each utility be directed to develop and test such a rate design as a pilot program prior to broad adoption; such a pilot program would determine whether and to what extent allowing all customers to take Standby Service rates will better align rates with the costs imposed by those customers on the distribution system. As part of the pilot, the City proposes to require utilities to implement shadow billing to enable customers to compare payments under the pilot rate to what they would have paid under existing rates. Alternatively, if the Commission decides not to pursue pilot programs, the City urges that the utilities be directed prior to implementation to conduct a full analysis on the potential cost-shifting impacts of the Standby Service rate design for non-participating customers.

As noted above, the CEP strongly object to introducing optional demand rates for mass market customers through increasing eligibility for standby rates. Accordingly, the CEP urge the Commission to reject Staff's proposal to direct utilities to adopt optional demand rates for mass market customers.

The Utility Intervention Unit of the New York State Department of State's Division of Consumer Protection (UIU) states that additional analysis is needed on the potential for cost shifts to nonparticipating customers as a result of the proposed opt-in standby rate. UIU also states that the optional rate, if adopted, should be coupled with an outreach and education plan at each utility.

In response to Staff's request for comments proposing a reasonable bill impact threshold, Digital Energy Corp. (Digital) submits that there is insufficient information available to propose such a threshold. Digital requests that the utilities be directed to perform a bill impact study based on the outcome of a "standby break-even analysis as a function of customer load factor for the service classes."

D. Determination

Given the Commission's finding in the preceding section regarding the clear superiority of standby rates to existing rate structures in sending accurate price signals to customers, it is reasonable to proceed with prompt implementation of tariff amendments filed by the utilities expanding Standby Service eligibility to all demand-metered customers in lieu of the customers' existing rate structure. Such tariff amendments shall be filed on not less than 20 days' notice to be effective on July 1, 2019. For customers that are not required to take Standby Service, the rate is to be offered on an opt-in basis. These opt-in rates are not "standby rates" under the traditional definition, since there is no requirement for on-site generation.

The Commission further agrees with the Staff Whitepaper recommendation to require that this opt-in to standby rates be effective for a period of not less than one year, to avoid customers switching between standby and standard rates to take advantage of seasonal rate fluctuations. In addition, for those utilities that do not include revenues from standby rate customers in their RDM, the tariff amendments shall include language that allows for the revenues from customers that opt into the standby rates to be included the RDM, thereby allowing for those customers to continue to contribute toward the revenue requirement of the OASC.

While it is the Commission’s intention that all customers, including mass market customers, be able to opt into their respective standby rates, it is not reasonable to immediately expand eligibility for the currently-existing mass market standby rates. First, there are currently no mass market standby rates available for Con Edison and O&R’s customers. Second, the existing mass market standby rates at the remaining utilities are not based on demand, but instead on a combination of fixed monthly charges and per-kWh energy charge. Once new demand-based standby rates applicable to mass market customers are developed, as discussed in the prior section, such customers will be allowed to participate in those rates on an opt-in basis.

With respect to the issue of bill impacts and limiting cost shifts to non-participating customers, the Commission will require an ongoing evaluation of the bill impacts to other customers after the rate is offered and customers have opted into the new rate. The Commission will therefore require the utilities to monitor the migration of customers, examine the impact on non-participating customers that occurs through RDM adjustments, and report back to the Commission annually. The specific requirements of these annual reports are described in greater detail later in this Order.

IV. Allocated Embedded Cost of Service Study

A. Background

The ACOS methodology builds upon an existing ECOS study by allocating all costs either on a local basis or on a shared basis. The ACOS multi-step process is as follows:

- Costs elements are functionalized to various categories under the ECOS, including transmission, primary, secondary, and customer costs, by Service Classification;
- The ACOS methodology then assigns a percentage of shared versus local to each item in each cost category for each Service Classification. For example, transmission costs are generally 100% shared, secondary costs are split but significantly more local in nature, and customer-related costs are generally 100% local;
- These allocated percentages of shared and local are multiplied by the revenue requirements for each ECOS cost category to determine the shared and local revenue requirements for each ECOS function for each Service Classification;
- The revenue requirement to be collected through the Customer Charge for each Service Classification is equal to that Service Classification’s customer-related costs. The revenue requirement to be collected through the Contract Demand Charge for each Service Classification is equal to the sum of each Service Classification’s local revenue requirements,

excluding those already included in the Customer Charge. The revenue requirement to be collected through the Daily As-Used Demand Charge for each Service Classification is equal to the sum of each Service Classification's shared revenue requirements; and

- The typical process of designing rates continues by dividing the applicable Customer revenue requirement, Shared revenue requirement, and Local revenue requirement by their applicable billing determinants to calculate the Customer Charge rate, Daily As-Used Demand rate, and Contract Demand Charge rate.

The ACOS methodology provides a pathway for periodic review of the revenue allocation between Contract Demand Charges and As-Used Demand Charges as part of general rate proceedings, rather than relying solely on the 2003 Standby Matrices. Allocating each of the cost elements into Customer, Shared, and Local charges will produce a more accurate revenue allocation and rate design among the Standby Service charges.[18]

B. Staff Whitepaper Recommendations

The Staff Whitepaper recommends that Central Hudson, Con Edison, NYSEG, RG&E, and O&R be directed to perform ACOS studies, in accordance with the methodology set forth above, and

[18] It should be noted that application of the ACOS methodology resulted in revenue shifts from the Contract Demand Charge to the Daily As-Used Demand Charge in the case of Niagara Mohawk. It may not always be the case, however, that use of the ACOS methodology will result in a reduction to the Contract Demand Charge and an increase in the Daily As-Used Demand charge compared to existing rates. Further, any modifications made to rate designs will likely cause bill impacts to individual customers based on the characteristics of their usage, even if such changes are implemented on a revenue-neutral basis to the Service Classification.

to include electric standby rates designed based on the results of those studies in their next electric rate case proceedings. According to the Staff Whitepaper, the process in the ACOS methodology of assigning percentages of shared versus local to each item in each cost category for each Service Classification will require analysis to determine the appropriate assignment for each category of costs.[19] The Staff Whitepaper requested comments from stakeholders on the extent of supporting data the utilities should be required to provide to support their assignment of costs between shared and local.

C. Comments

The City and Digital support Staff's recommendation that the Commission direct each utility to perform an ACOS study in order to develop more appropriate Standby Service and Buyback Service rates.[20] The City urges that standby rates be recalibrated to ensure that costs are properly allocated to customers based on proper cost causation principles (e.g., local costs recovered through Contract Demand charges and shared costs recovered through As-Used Demand charges) instead of the arbitrary allocation percentages set forth in the 2003 Standby Matrices. The City points to National Grid's ACOS study from 2016, which demonstrated that the 2003 Standby Matrices were inaccurate and that lower Contract Demand charges and higher As-Used Demand charges were appropriate.

[19] Given its complexity, the Staff Whitepaper does not recommend the marginal-cost-based methodology used by RG&E. According to the Staff Whitepaper, however, it may be reasonable to utilize marginal costs to inform the ACOS allocations percentages between shared versus local for the various items in each cost and Service Classification.

[20] Digital further recommends that Staff provide a "report template" that is standardized across all utilities for ease of use when comparing data across utilities.

AEE Institute urges the Commission to direct Con Edison in particular to undertake an updated ACOS study as part of its current rate case, and to adjust its standby and buyback rates accordingly. More generally, AEE Institute supports more accurate accounting between local and shared costs; it submits that in the absence of reform and a more accurate allocation, contract demand charges will inhibit the growth of energy storage projects in New York and create an artificial cost for power injections that provide capacity and valuable support to the grid. According to AEE Institute, data from other jurisdictions suggest that "local" costs (customer-specific capacity costs) in New York are substantially higher than in other jurisdictions, even after adjusting for the more expensive nature of building infrastructure in New York City and the surrounding area.

In categorizing local versus shared costs, AEE Institute submits that, for a local cost, the utility should be required to demonstrate that the cost would not be incurred but for that specific customer/project's demand or injections, is an ongoing incurred cost driven by that customer/project's demand or injections (and not a one-time cost that should be recovered through interconnection fees), and is impacted in the same manner by exports as it is by customer/project demand. Based on this, AEE Institute states that a cost should only be considered local if: "(1) an increase in demand or a power injection from a single customer/project that could contribute equally to an increase in costs; and, (2) only one customer/project drives the cost, such that the cost cannot be avoided or diminished by the injections of another customer/project." According to AEE Institute, a true customer-specific, local cost is driven by the peak flow of power, regardless of the direction. If a category of cost has the potential to be reduced by an injection, it should be classified as shared. If shared capacity costs are defined as local costs, then it is possible that a storage system would be overcharged for local costs (via contract demand) when it is in fact providing a benefit, such as reducing stress on feeder and transformers that are used by multiple customers.

CEP opposes the ACOS methodology outlined by Staff as part of their rejection of demand charges as a basis for rates for mass market customers, and urges that demand driven costs be recovered on an hourly basis through energy charges, which would provide a clearer price signal for customers to respond to. CEP also reiterates its objection to the current approach to calculating customer charges, which it says results in customer charges that are excessive and based on a flawed approach. CEP maintains that customer charges should recover only those costs that vary with adding an additional customer to the system, and should include only the costs of billing, customer service, service line drop, and a share of metering costs. CEP asks the Commission to reject Staff’s proposal to require the utilities to conduct an ACOS study that includes more than the incremental cost of connecting a customer in the customer charge for mass market customers, in standby rates or otherwise.

With respect to the allocation of Demand-Related Costs to Contract and Daily As-Used Demand charges, CEP claims that the current allocation is likely over-allocating costs to Contract Demand charges for mass market customers. According to CEP, the vast majority of distribution system costs for mass market customers are shared, meaning that these costs are not incurred to serve one individual customer. CEP submits that collecting additional costs in a Contract Demand charge that should be allocated to a Daily As-Used Demand charge is flawed because it does not align the rate design with cost causation.

CEP requests that the Commission require utilities to reevaluate the allocation of demand-related costs to Contract and Daily As-Used Demand charges. According to CEP, Contract Demand charges should be minimal for secondary distribution costs and zero for primary, substation, and transmission costs.

Consumer Power Advocates (CPA) is concerned with the Staff Whitepaper's "apparently unqualified endorsement" of the ACOS approach to the exclusion of any marginal cost-based approach. CPA reiterates its longstanding support for greater use of marginal cost of service (MCOS) studies in the development of more efficient rate structures. CPA states that by rejecting MCOS-based approaches, the Staff Whitepaper may have "hamstrung" REV and its objectives. CPA notes the position of Staff in the RG&E case, which acknowledged that marginal costs may be used "to inform the ACOS allocation percentages between shared versus local for the various items in each cost and service classification," which suggests that marginal cost principles will not be ignored altogether. According to CPA, the proposition that use of marginal costs will result in greater allocative efficiency outcomes should be "uncontroversial."

The Joint Utilities argue that mandating the ACOS approach as the only way of developing Standby Service rates is "needlessly rigid." Noting the reference in footnote 22 of the Staff Whitepaper to the possibility of using marginal costs to inform the ACOS allocation percentages between shared versus local for the various items in each cost and service classification, they request flexibility to compute local and shared cost components in a manner that most accurately reflects such costs, "including approaches that may rely on marginal costs or alternative embedded cost studies."

D. Determination

Using the ACOS methodology will provide a pathway for periodic review of the allocation of each of the cost elements into Customer, Shared, and Local charges and will result in a more accurate revenue allocation and rate design among the Standby Service charges. The Commission therefore adopts the recommendation in the Staff Whitepaper and directs the utilities, other than Niagara Mohawk,[21] to perform an ACOS study using existing approved ECOS studies, in accordance with the methodology described above, and provide draft tariff leaves reflecting the revised Standby and Buyback Service rates designed using the companies' ACOS results. The ACOS studies and draft tariff leaves shall be filed by September 4, 2019. In addition, the draft tariffs shall include more granular commodity rates for standby rate customers based on NYISO hourly LBMP and ICAP tags. The Commission expects Staff to utilize the existing VDER Rate Design Working Group for further analysis and discussion of the utilities' ACOS methodologies and resulting proposed standby rates and provide the results for subsequent consideration by the Commission. It is expected that the Commission will issue an order with respect to the application of the ACOS methodology at each utility. That order, in turn, will require the utilities to submit compliance filings of standby rates implementing that guidance.

With respect to the comments of the Joint Utilities and CPA regarding what they perceive to be exclusive reliance on

[21] Niagara Mohawk initially proposed an ACOS approach in its October 7, 2016 Standby and Buyback Rates filing in Case 16-M-0430; the approach was subsequently implemented as part of its recently approved rate plan in Case 17-E-0238. While the ACOS study has already been completed, Niagara Mohawk shall still file draft tariffs reflecting the underlying rate design changes required by this Order.

ACOS studies in developing Standby Service rates, the Commission notes that considerable analysis and judgment will be required in assigning percentages of shared versus local to each item in each cost category for each Service Classification. Utilities will be required to provide supporting data to justify their proposed assignment of costs between shared and local. In exercising this judgment in applying ACOS studies in the development of Standby Service rates, the goal of the process is to produce a relatively consistent approach across utilities, which will not necessarily exclude consideration of approaches that may rely on marginal costs or alternative embedded cost studies.

In that regard, while not specifically endorsing the test offered by AEE Institute to classify a cost as a local cost, the Commission does agree that a local cost is driven by the peak flow of power, regardless of the direction, and any category of costs that has the potential to be reduced by an injection should not be classified as local. These principles should guide the process used by utilities in their allocation of local versus shared costs in their ACOS studies.

V. Granular As-Used Demand Charges

A. Background

Con Edison's Standby/Buyback Pilot, operated under Rider Q, represents a significant development in providing more granular time- and location-varying price signals to customers. Under the Standby/Buyback Pilot, the summer Super-Peak Daily As-Used Demand charge is reduced from a ten-hour period that applies from 8 AM to 6 PM throughout the service territory to a four-hour period that varies by network based on the hours that the network experiences peak load conditions. There are four specific Super-Peak periods defined by the applicable Commercial System Relief Program (CSRP) peak-shaving demand response program call hours, which vary based on which network or radial load area a customer is interconnected to: 11 AM to 3 PM; 2 PM to 6 PM; 4 PM to 8 PM; or 7 PM to 11 PM.[22] The four-hour Super-Peak Daily As-Used Demand charges are only applicable during the summer months, defined as June through September of each year.

In addition to compressing the Super-Peak period, the Standby/Buyback Pilot includes revenue recovery shifts from the on-peak period to the Super-Peak period, which vary based on whether the individual network is considered a high-value network needing additional load relief to help support local reliability under the Distribution Load Relief Program (DLRP), a local reliability demand response program (DLRP Tier 2 Networks).[23] In DLRP Tier 2 Networks, an additional 35% of revenues is shifted from recovery through the on-peak Daily As-Used Demand Charge into the Super-Peak Daily As-Used Demand Charge. Twenty percent of revenues is shifted from recovery through the on-peak Daily As-Used Demand Charge into the Super-Peak Daily As-Used Demand Charge in all other networks.

Con Edison is unique in New York as the only utility to have both an On-Peak and Super-Peak Daily As-Used Demand charge as well as differing CSRP call windows[24] and one of only

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[22] The on-peak Daily As-Used Demand period for customers in the 7 PM to 11 PM CSRP call window is also modified from 6 AM to 10 PM, to 8 AM to 12 AM.

[23] DLRP Tier 2 Networks are defined as the ten lowest reliability networks based on a three-year rolling average of Network Reliability Index rankings.

[24] Each of the other utilities calls CSRP events during 2 PM to 6 PM only.

two utilities with differing DLRP payment rates based on customer location.[25]

B. Staff Whitepaper Recommendation

The Staff Whitepaper states that while the general format of the Standby/Buyback Pilot is a reasonable example that other utilities could follow to design more granular Daily As-Used Demand charges, its exact details may not be applicable to the other New York utilities, and, therefore additional information and process is necessary to develop such rates that could be adopted by the Commission. As a first step toward being able to implement more granular Daily As-Used Demand charges for utilities other than Con Edison, the Staff Whitepaper recommends that the Commission direct Central Hudson, Niagara Mohawk, NYSEG, RG&E, and O&R to develop more granular Daily As-Used Demand Charges with Off-Peak, On-Peak, and Super-Peak charge components during the summer period for their existing standby rates and submit such rates for Commission review and approval. In addition, the Staff Whitepaper

[25] O&R also offers tiered DLRP payment rates. Niagara Mohawk, NYSEG, and RG&E do not currently have areas eligible for participation in the DLRP, but may identify eligible areas and offer DLRP participation in the future. Central Hudson does not offer a DLRP.

requested stakeholder comments on several questions related to the implementation of granular rates.[26]

C. Comments

AEE Institute and NY-BEST strongly support Staff's recommendation to require the utilities, other than Con Edison, to develop more granular Daily As-Used Demand Charges with Off-Peak, On-Peak, and Super-Peak charge components. They submit that all utilities should have a super-peak charge unless a utility can demonstrate that its network or system costs are flat throughout the day and that higher demand during peak hours imposes no additional costs or wear and tear on its system. This super-peak charge should also be as granular as possible, both from a location and time perspective. NY-BEST suggests that the implementation by other utilities should be flexible and reflect the differences between utility service territories.[27]

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[26] Stakeholders were asked to comment on the following questions: (i) does each utility require a Super-Peak charge? (ii) should each utility implement Daily As-Used Demand rates which vary by season? (iii) should the Super-Peak charge apply during the utility system peak demand period, the peak period of the network or load area in which individual customers are located, or the Service Classification peak demand period? (iv) should the Super-Peak charge rate vary depending upon whether a customer is interconnected to a high-value network or load area? (v) what value or percentage of revenue should be recovered through the Off-Peak, On-Peak, and Super-Peak charge?

[27] In response to the specific questions raised by Staff in the Whitepaper, NY-BEST states that (i) yes, each utility should implement a Super-Peak charge; (ii) yes, seasonal variation should be considered, (iii) the Super Peak should be aligned with the network or load area peak in which the individual customer is located, and (iv) it opposes a design where the Super-Peak value is very low in low-stress networks and only ramps up in high-stress areas; rather, all networks should have access to a Super-Peak demand charge tariff where the Peak time rate is at double the base demand charge.

NYPA also supports development of a utility Standby Service rate structure with granular As-Used Demand charges featuring time- and location-varying price signals, noting that the current Standby Service rate structure is based on an eight to ten hour Daily-As-Used Demand measurement period, which is too lengthy to encourage customer response. In contrast, NYPA cites Con Edison's Standby/Buyback Pilot, which provides for a 4-hour window for the summer Super-Peak Daily-As-Used Demand charge, and better aligns with utility system peaks.

The City neither supports nor opposes Staff's recommendation, but suggests that it may be premature given that the Standby/Buyback Pilot operated by Con Edison under Rider Q was adopted only recently by Con Edison and apparently has no participating customers. Moreover, the Con Edison Standby/Buyback Pilot may not be appropriate for all other New York utilities, given Con Edison's unique service territory. The City suggests that a better course of action may be to monitor Con Edison's pilot and await actual data and results before imposing the rate design on all utilities.

The Joint Utilities also submit that Staff's recommendation is premature, given that the Pilot has been in effect for slightly more than a year and has only one participant to date. Until the Pilot has generated more "robust information," the Joint Utilities suggest that it is not possible to make any determinations regarding the scalability of the Pilot design and its applicability to other utilities.

Digital suggests that the questions posed by Staff in the Staff Whitepaper cannot be answered without a study to determine the bill impacts of proposed rate designs. On a related issue, CEP submits that the current Standby Service On-Peak time period is excessive and should be reduced to provide a better price signal to customers and align with cost causation.

According to CEP, the current time periods are expansive, covering in excess of 14 hours for all utilities. Given that the class level peaks for mass market customers in New York are generally later in the day, the on-peak period for the proposed Standby Service rates should reflect this reality and focus on a smaller number of hours to allow customers to effectively respond to the price signal. CEP submits that the current on-peak periods do not align the rate with cost causation, given that the peak period is not reflective of actual system peaks. CEP urges the Commission to reconsider the on-peak time period currently in place for all utilities' standby rate option and focus instead on hours that are most likely to contain the peak for that service class.

D. Determination

Con Edison's Standby/Buyback Pilot, operated under Rider Q, represents a significant improvement in providing more granular time-varying price signals to customers. Although it has been in effect a relatively short period of time, the pricing elements are straightforward and there is sufficient information available for the other utilities to start the process of implementing more granular Daily As-Used Demand charges. The Commission therefore directs the utilities other than Con Edison to develop more granular Daily As-Used Demand Charges with Off-Peak, On-Peak, and Super-Peak charge components during the summer period for their existing standby rates. These new components shall be included in the draft tariffs submitted by utilities as part of the September 4, 2019 filings required in the preceding section. Following Staff's evaluation, including input from the VDER Rate Design Working Group and subsequent consideration by the Commission, the Commission expects to issue an order directing compliance filings by the utilities to implement these Daily As-Used Demand

Charges with Off-Peak, On-Peak, and Super-Peak charge components.

VI. Applicability of the Reliability Credit

A. Background

The Reliability Credit mechanism, as implemented in the REV Track Two Order,[28] is designed to compensate Standby Service customers for consistently and reliably using DERs and other behind-the-meter load reductions instead of taking service from the grid during summer demand-billed hours. Specifically, the Reliability Credit provides a monetary credit based on the kW difference between a customer's Contract Demand kW and the maximum kW demand the customer places on the grid during the on-peak Daily As-Used Demand hours over a two-summer period, multiplied by the customer's applicable $/kW Contract Demand Charge rate. The Reliability Credit is a somewhat imprecise measure, in that it provides a proxy of grid value based on the local Contract Demand Charge measured during the shared Daily As-Used Demand hours during the summer only.

Beyond requiring that all DERs be connected behind the customer's meter, Standby Service includes several DER configuration options, including allowing customers to interconnect DERs separately from any other load with provision for station power. An example is a standalone battery that takes Standby Service for battery charging and discharges directly to the grid. Such a standalone energy storage system could potentially avoid paying for any local distribution facilities if the customer charges only during off-peak hours. Utility Offset Tariffs also allow customers to directly connect DERs to the grid and offset separately metered usage, the

[28] Case 14-M-0101, Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016).

demand-based analog of remote net energy metering. Under this arrangement, it is possible for customers to offset As-Used Demand charges, avoid paying Contract Demand Charges under the Reliability Credit if their generation capacity is greater than or equal to their maximum usage, and potentially earn Value Stack compensation for net injections.

B. Staff Whitepaper Recommendation

The Staff Whitepaper states that the availability of the Reliability Credit must be limited in order to avoid double-paying applicable DERs for the value they provide to the grid – once under the Value Stack through the DRV or LSRV, and again through the Reliability Credit – and to ensure that customers pay a fair share of the costs of local facilities. The Commission has already approved similar exclusions for standalone electric energy storage systems from earning the Reliability Credit at Con Edison.[29] The Staff Whitepaper recommends that the utilities be directed to modify their respective Standby Service tariffs to restrict eligibility for the Reliability Credit to exclude customers' DERs that receive Value Stack compensation for exports to the system, including customers participating in an Offset Tariff option.

C. Comments

The Joint Utilities, CPA, and Digital all support Staff's recommendations; the Joint Utilities note that Con Edison has already partially implemented the required adjustment.

Digital further proposes a refinement to the way kW value is used to calculate the Standby Reliability Credit, claiming that the current method of using three exclusion

[29] Case 17-E-0458, Con Edison Energy Storage Tariff, Order Approving Tariff Changes with Modification (issued February 22, 2018).

periods is arbitrary. Digital recommends that an average hourly kW load meter performance measurement over the applicable performance period be used, which would simplify the calculation and put it in line with others (like the NYISO) that use reliability as a factor when paying for performance.

The Joint Utilities also request that the Commission consider other adjustments where the Reliability Credit mechanism can result in customers receiving compensation for reasons other than generator performance, citing the example of a customer setting maximum monthly demands that are less than contract demand in the case of weather that is cooler than normal in two consecutive summers; in such a case, the customer would receive a credit even with poor generator performance, according to the Joint Utilities. They urge the Commission to modify the Reliability Credit to focus on generator performance or eliminate it entirely in favor of compensation based on measured generator output to assure reliable operation.

D. Determination

Consistent with broad support by stakeholders, the Commission directs the utilities to modify their respective Standby Service tariffs to restrict eligibility for the Reliability Credit by excluding customers' DERs that receive Value Stack compensation for exports to the system.[30] Such tariff amendments shall be filed on not less than 20 days' notice to be effective on July 1, 2019. Comments by Digital and the Joint Utilities regarding the methodology for calculating

[30] This restriction applies both to resources installed behind the same meter as customer load to directly serve that load and to standalone resources offsetting usage behind separate meters through an offset tariff. Where a resource using an offset tariff does not receive Value Stack compensation, that resource would remain eligible for the reliability credit.

the Reliability Credit are beyond the scope of this inquiry, and therefore will not be addressed at this time.

VII. Expansion of the Multi-Party Campus Offset Tariff

A. Background

The Standby Service Offset Tariff allows a customer to interconnect its generating equipment to a utility's primary voltage distribution system and offset Daily As-Used Demand of its separately metered load connected to the secondary voltage distribution system. In this way, the Offset Tariff allows for remote net demand metering, virtually using the utility's distribution system to deliver power from the generator to the customer's end use instead of customer-owned equipment. Under the Offset Tariff, each account where demand is offset in this manner must take service under Standby Service rates.

The Offset Tariff was first instituted at Con Edison and initially allowed only for generation to offset the Daily As-Used Demand of a single building. In 2011, the Commission directed Con Edison to expand the Offset Tariff to allow for a customer with generation to offset load of multiple buildings (of that same customer) in a campus setting,[31] provided that the generator and buildings were located on a single premise, which was later implemented in the Campus Offset Tariff Order.[32] Among the issues considered in the Campus Offset Tariff Order was whether allow a single generator to offset the load of multiple customers under the Campus Offset Tariff, the level of Contract Demand kW amount to charge each building taking service under the Campus Offset Tariff, and whether to require buildings

[31] Case 11-E-0299, Con Edison Offset Tariff, Order Approving Tariff Amendments with Modifications (issued November 17, 2011).

[32] Case 11-E-0299, supra, Order Approving Tariff Amendments with Modifications and Granting Petition for Rehearing (issued October 18, 2012) (Campus Offset Tariff Order).

served under the Campus Offset Tariff to be both located on the same premises and electrically interconnected. The Commission determined that a single generator would not be allowed to offset the load of multiple customers and required Contract Demand Charges for each building to be based on each building's non-coincident maximum demand. The Commission also determined that all buildings served under the Campus Offset Tariff must be located on the same premises, but did not require such buildings to be electrically interconnected.

Con Edison thereafter convened a collaborative to consider expanding the Offset Tariff to include allowing a single generator to offset the load of multiple customers,[33] which ultimately resulted in a Con Edison petition to allow such offset to multiple customers provided that such customers were located in the same building.[34] As part of the REV Track Two Order, the Commission required each of the utilities to institute Con Edison's then-current Offset Tariff provisions, including single-building and Campus configurations, and required that each of the utilities allow a generator to offset the load of multiple customers provided that such customers are within the same building, similar to Con Edison's Multi-Party Offset Petition.[35] At this time, all of the utilities have complied by instituting both the single-customer, single-building Offset Tariff; the multi-customer, single-building

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[33] Case 13-E-0030, 2013 Con Edison Electric Rates, Order Approving Electric, Gas, and Steam Rate Plans in Accord with Joint Proposal (issued February 21, 2014).

[34] Case 16-E-0196, Con Edison Multi-Party Offset, 13-E-0030 Standby Service Multi-Party Offset (filed April 4, 2016) (Multi-Party Offset Petition).

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

Multi-Party Offset Tariff; and the single-customer, multi-building Campus Offset Tariff.

As part of Con Edison's 2016 electric rate plan, further modifications to the Offset Tariff were implemented subsequent to the REV Track Two Order.[36] The 2016 Con Edison Rate Order builds upon the Multi-Party Offset Tariff and allows the load of multiple customers in multiple buildings to be offset by a common generator (Multi-Party Campus Offset Tariff), provided that such customers are located on the same premises and are connected to the generating facility via a thermal loop[37] to ensure that such customers are proximate to the generating facility. The Multi-Party Campus Offset Tariff allows for a number of configurations that the current Multi-Party Offset tariff does not (for example, a college campus with a cafeteria separately metered and operated by a third party).

B. Staff Whitepaper Recommendations

Staff recommended in the Staff Whitepaper that the Commission direct Central Hudson, Niagara Mohawk, NYSEG, RG&E, and O&R to develop and file a Multi-Party Campus Offset Tariff similar to that currently in place at Con Edison. Stakeholders were also requested to provide comments regarding whether the eligibility requirements for the Con Edison tariff – including the requirement of a thermal loop to establish proximity to the

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[36] Case 16-E-0060, Con Edison Electric Rates, Order Approving Electric and Gas Rate Plans, (issued January 25, 2017) (2016 Con Edison Rate Order).

[37] In this context a thermal loop refers to customer usage of generator waste heat through steam, hot water, or chilled water equipment. Con Edison's thermal loop requirement (PSC No. 10 – Schedule for Electricity Service, leaf 157.1.1) states that multiple buildings seeking to participate in a multi-party arrangement must be "connected to the generating facility by a private thermal loop that delivers, steam, hot water, or chilled water."

generating facility – are appropriate for statewide implementation, or to suggest alternate requirements.

C. Comments

The City, NYPA, NY-BEST, and Digital all oppose using the Con Edison Multi-Party Campus Offset Tariff as the basis for extending the eligibility requirements for statewide implementation. In particular, these parties take issue with continuation of the thermal loop requirement. The City submits that the thermal loop requirement is overly restrictive, and should be expanded to allow the Multi-Party Offset tariff to apply to other buildings located in proximity to each other, which it says would increase developer flexibility in designing microgrid configurations.

NYPA notes that for newer technologies (including large solar installations and battery storage resources), restricting physical locations of a generator and loads based on the configuration of a thermal distribution system will impede deployment of these technologies in offset arrangements. Instead of a thermal loop requirement, NYPA urges the Commission to consider fulfilling a “proximity” requirement through the concept of an “electric loop” based on participating accounts being supplied or serviced from a common point on the distribution system, such as a substation or transformer that serves all entities within the multi-party arrangement.

NY-BEST argues that the thermal loop requirement effectively restricts the sharing of DERs to CHP assets and thus is counter to a technology-neutral approach. NY-BEST submits that a proximity requirement could be fulfilled by requiring the sites to be within the same CSRP zone or within the same secondary network. Similarly, Digital suggests that the requirement be based on the generation and off-takers being in the same utility network. Digital also urges, in the case of

Single-Party Offset Tariffs, that the restriction be eased on the off-taker having to be in the same names as the generation asset in order to allow building owners to participate if the majority owner of the generation asset and the off-taker is the same.

In addition to opposing the thermal loop requirement, the City and NYPA object to the provision in Con Edison's tariff that prohibits NYPA accounts from participating in a multi-party offset arrangement with non-NYPA accounts, which significantly hinders NYPA customers (including the City) from using the Multi-Party Campus Offset tariff. The Joint Utilities do not oppose the expansion of this requirement and note that Niagara Mohawk currently has a proposal before the Commission that is consistent with Con Edison's tariff.[38]

D. Determination

The Commission approved Con Edison's Multi-Party Campus Offset Tariff in January 2017, as an element of the Joint Proposal submitted in that proceeding which reflected the agreement of 22 parties representing diverse interests.[39] In adopting this arrangement, the Commission noted that it would encourage customers to actively engage with the utility to contribute value to the distribution grid, thereby resulting in reduced transmission and distribution infrastructure investment and lower bills for customers.[40] This arrangement should be

[38] On August 10, 2018, Niagara Mohawk submitted a proposed amendment to its Standby Multi-Party Offset Tariff Provision that would expand eligibility through the definition of "premise" to include customers across multiple buildings that are connected to the same generating facility by a private thermal loop. Case 18-E-0500, Petition of Niagara Mohawk Power Corporation d/b/a National Grid for Proposed Amendment to Standby Service Multi-Party Offset Tariff Provision.

[39] 2016 Con Edison Rate Order, p. 51.

[40] 2016 Con Edison Rate Order, p. 52.

available statewide, and requiring the other utilities to replicate the Con Edison Multi-Party Campus Offset Tariff is a reasonable means of achieving that objective.

The Commission appreciates the comments from stakeholders regarding the appropriateness of extending the eligibility requirements for the Con Edison tariff – including the requirement of a thermal loop to establish proximity to the generating facility – for statewide implementation and their suggestions regarding alternate requirements. The thermal loop provision represents a reasonable means of effecting a proximity requirement and, as noted by NY-BEST, is particularly well-suited for CHP facilities. In fact, given that CHP is ineligible for inclusion under the VDER Value Stack, this Offset Tariff is necessary for CHP installations to receive some of the benefits available to other technologies eligible under VDER. For these technologies, such as large solar installations and battery storage resources, DER operators will be adequately compensated for the value they provide or cost they offset in the local distribution system through the Value Stack without having to expand offset arrangements through elimination of the thermal loop requirement. The Commission therefore accepts Staff’s recommendation to use the existing Con Edison Multi-Party Campus Offset Tariff as the basis for implementation of multi-party offset arrangements throughout the state. In the event that a customer may choose to co-locate a VDER-eligible DER with CHP, the VDER-eligible DERs should be compensated separately through the Value Stack and not included in the customer’s offset tariff allocation of generator output.

New York City and NYPA’s request that the offset tariffs be modified to allow non-NYPA accounts and NYPA accounts to participate in offset agreements is declined. The different service classes and tariff provisions applicable to NYPA and non-NYPA accounts make it impractical for offset arrangements between them.

The Commission directs that Central Hudson, NYSEG, RG&E, and O&R develop and file draft Multi-Party Campus Offset Tariffs, similar to those currently in place at Con Edison, as part of their September 4, 2019 draft tariff filing. Niagara Mohawk has already submitted such a proposal in Case 18-E-0500, and the Commission directs Staff to review that filing for consistency with the requirements of this Order.

VIII. Buyback Service Rates

Buyback Service was initially implemented in New York in response to the federal Public Utility Regulatory Policies Act of 1978 (PURPA). At the time PURPA came into effect, New York State utilities were vertically integrated, with individual utilities responsible for owning and maintaining power generation, transmission, and distribution systems. PURPA allows eligible non-utility owned generators to export power onto the utilities’ transmission and distribution systems and required the utilities to purchase such power. Buyback Service tariffs were developed to fulfill the utilities’ new obligation to purchase power from non-utility generators.

The Commission subsequently restructured the generation and bulk transmission businesses, required utilities to sell existing generation stations, and shaped the development of the energy and capacity markets operated by the NYISO. Therefore, many non-utility generators now sell power through the NYISO wholesale markets. However, Buyback Service remains as an option for eligible customer-owned generators that wish to export electricity to the utility distribution system, do not qualify for NEM under PSL §§66-j or 66-l or other DER compensation options such as the Value Stack tariffs established in this case, and do not wish to participate directly in the NYISO wholesale market.[41]

Similar to Standby Service, Buyback Service is designed to ensure that customer-owned generators connected to utilities' distribution systems pay their fair share of fixed system costs and costs related directly to serving them as customers. Buyback Service rate design includes the same concepts of a Customer Charge and a Contract Demand Charge employed under Standby Service; in fact, in many cases the same Customer Charge and Contract Demand Charge developed for Standby Service are applied to Buyback Service customers inasmuch as the same types of distribution system infrastructure is required to deliver electricity used or produced by customers. As with Standby Service, the Buyback Service Customer Charge is designed to recover fixed system costs, while the Contract Demand Charge is designed to recover the costs of local facilities specifically installed to meet individual customer needs. Unlike Standby Service, however, Buyback Service does not have a Daily As-Used Demand component. Instead, utilities pay Buyback Service customers for net energy injections and resulting

[41] Azure Mountain Power raises an issue not expressly addressed by Staff's Whitepaper regarding the applicability of Buyback Service rates for vintage renewable DERs that are eligible for compensation under PSL §66-j. Specifically, it objects to the introduction of a Customer Charge and a Contract Demand Charge for these DERs. Although these generators qualify for compensation under PSL §66-j, they are compensated under buyback rates and have not yet made the switch to NEM or VDER, and thus arguably do not impose the sort of cost shifts addressed in this Order. Azure Mountain Power requests that generators eligible under PSL §66-j be exempted from any new charges imposed on buyback rate customers. The Commission agrees that such generators, to the extent they are eligible for NEM or VDER rates and are taking service thereunder, would enable them to avoid such charges, and thus are exempt from new charges imposed on Buyback Service customers by this Order.

capacity. For net energy injections under Buyback Service, the utility pays a price based on the NYISO-market LBMP at the time energy is produced. For capacity, the utility pays a price that reflects the cost of capacity, or ICAP, that it avoids having to purchase from the NYISO market based on injections during the statewide NYISO peak hour.

IX. Grid Access Contract Demand Charges

A. Background

Most utilities charge Buyback Service customers a monthly Customer Charge and a Contract Demand Charge. Similar to Standby Service equivalents, these charges are designed to recover the customer-related costs and local facilities costs associated with customer export of power to the utility grid. They can be considered grid access charges, to the extent that customers interconnected to the grid must pay these charges regardless of whether or not the service is actually used. While the terms of Buyback Service are similar among utilities, there is some variation in whether utilities impose these grid access charges and how such charges are designed.

In the case of buyback-only customers (customers not taking service under another service classification), most of the utilities impose a Customer Charge and a Contract Demand Charge based on the standby rate applicable to the customer's OASC; only Niagara Mohawk does not have a Customer Charge or a Contract Demand Charge for buyback-only customers.

There are wider differences among utility practices with respect to charges applicable to customers taking service under both buyback and another service classification. For these customers, Con Edison waives the buyback Customer Charge and a Contract Demand Charge is assessed only on generator capacity greater than the customer's maximum demand. Similar to Con Edison, both Central Hudson and O&R charge an incremental

Contract Demand Charge for any generator kW served under Buyback Service greater than the maximum annual usage demand served under the other Service Classification. However, both utilities also impose an incremental monthly Customer Charge or Metering Charge to dual-service customers. NYSEG, RG&E, and Niagara Mohawk do not impose either an incremental Customer Charge or an incremental Contract Demand Charge under Buyback Service to dual-service customers.

B. Staff Whitepaper Recommendation

To the extent that a buyback-only customer does not pay a Customer Charge or Contract Demand Charge based on its usage of the grid or, likewise, that a dual-service customer does not pay for additional Contract Demand based on the local facilities that are built to serve its generation over and above those which are already included in the cost recovery of its other service classification, other customers pay for the customer-related or local facilities costs not recovered from the customer that imposes them. The Staff Whitepaper recommends tariff revisions to Buyback Service rates to eliminate this cost shift, thereby ensuring that all customers pay for their fair share of the costs they impose. In particular, the Staff Whitepaper recommends that: (1) Niagara Mohawk be directed to design and implement Buyback Service rates for buyback-only customers to include a Customer Charge and a Contract Demand Charge; and (2) Niagara Mohawk, NYSEG and RG&E be directed to design and implement rates for dual-service customers to include an incremental Contract Demand Charge for generator capacity kW greater than the customer’s maximum annual usage demand.

C. Comments

The Joint Utilities support the recommendations in the Staff Whitepaper. Digital suggests that these rates should be set in each utility’s next general rate proceeding on the basis of an ACOS, in order to set fair and accurate rates based on cost causation that are updated on a regular basis.

D. Determination

As the Customer Charge and Contract Demand Charge reflect actual costs that, if not charged through Buyback Service rates, will be shifted to other customers, the Commission accepts the recommendations in the Staff Whitepaper, and directs Niagara Mohawk, NYSEG and RG&E to develop draft tariff filings reflecting these recommended revisions to Buyback Service rates, incorporating the results of their ACOS studies, and include them as part of the September 4, 2019 filing.

X. Purchase of Installed Capacity from Buyback Service Customers

A. Background

Each utility's tariff allows eligible customers to sell energy and capacity directly into the NYISO's markets or to the utility through Buyback Service. Even though the utilities' Buyback Service tariffs require that customers meet the same operating requirements imposed by the NYISO to sell energy and capacity to the utility, allowing customers to either sell to the NYISO, or directly to the utility, represents an important option for customers; the interconnection requirements and associated costs, as well as the rates paid by customers, can be different for a DER selling into the NYISO market versus directly to the utility.[42] While each utility's tariff contains language allowing for the purchase of Unforced Capacity (UCAP) from eligible customers through their respective Buyback Service

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[42] Customers directly participating in the NYISO markets are charged under the Open Access Transmission Tariff (OATT) regulated by the Federal Energy Regulatory Commission (FERC).

tariffs,[43] the specific language governing the purchase of UCAP differs slightly among utilities. The tariffs of Central Hudson, Niagara Mohawk, NYSEG, and RG&E each specify that customers with over 100 kW of generation capacity may negotiate a contract with the utility for sale of capacity through the Buyback Service, which in effect means that those utilities are obligated to enter into negotiations with customers to contract for such capacity. While Con Edison's and O&R's tariffs specify that purchases of UCAP through the Buyback Service are permissible, there is no specific tariff language granting customers the right to negotiate with the utilities for such contracts, thereby leaving it to the discretion of Con Edison and O&R as to whether to purchase UCAP through Buyback Service. DER developers routinely complain that Con Edison is not willing to purchase such capacity through its Buyback Service. This represents a potential barrier to DER adoption.

Also inconsistent among the utilities' Buyback Service tariffs is the amount of UCAP that each utility may purchase from customers. Both Con Edison and O&R's tariffs only allow the purchase of up to 2 megawatts (MWs) of UCAP per customer, whereas Niagara Mohawk's tariff states that the company will purchase up to 80 MWs of UCAP per customer. Central Hudson,

[43] The "Unforced Capacity" methodology estimates the probability that a particular resource will be available to serve load, taking into account forced outages and forced deratings. Thus, each generator's UCAP amount is its Installed Capacity (ICAP) adjusted down by its particular propensity to incur forced outages and deratings. At the aggregate purchase level, utilities have their overall load levels translated into both ICAP purchase requirements and UCAP purchase requirements, the latter being approximately 5-10% less than the former, depending on the relevant system average outage rate. This leads to the result that capacity prices expressed for purchasing UCAP MWs from the NYISO are approximately 5-10% higher than those expressed in ICAP terms.

NYSEG, and RG&E do not have specified maximum capacity purchase limits in their respective tariffs.[44]

B. Staff Whitepaper Recommendation

The Staff Whitepaper recommends that Con Edison and O&R be directed to modify their respective Buyback Service tariffs to require those companies to purchase UCAP from eligible customers at the prevailing NYISO strip[45] capacity market price. The Staff Whitepaper further recommends that each of the other utilities be directed to file tariff amendments clarifying the utility's obligation to purchase UCAP from customers.

The Staff Whitepaper also recommends that the Commission set a maximum project-level UCAP limit of 5 MW for purchases of capacity from technologies not eligible for the Value Stack through Buyback Service, and to require each utility to incorporate that limit in subsequent tariff revisions.[46]

The Staff Whitepaper also requested comments from stakeholders as to whether each utility should set a maximum cumulative UCAP purchase threshold to avoid utility UCAP purchases through Buyback Service distorting the NYISO's UCAP strip auction price-setting process and, if so, how such a threshold should be determined.

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[44] While Central Hudson, NYSEG, and RG&E do not specify a maximum capacity limit, PURPA only applies to Qualifying Facilities of 80 MW capacity or less.

[45] The NYISO publishes three types of UCAP prices: (1) those deriving from 6-month forward "strip" auctions, which establish prices for each 6-month capability period, summer and winter; (2) monthly auction prices; and (3) monthly "spot" prices which are established by comparing spot supply bids to the tariff's formulaic ICAP Demand Curve.

[46] This 5 MW project-level UCAP limit is argued to be reasonably consistent with the maximum project size eligible for Value Stack compensation mechanism and would be applied uniformly across the state.

C. Comments

The City supports Staff's recommendation that Con Edison be directed to modify its Buyback Service tariffs to require the utility to purchase capacity from eligible buyback customers at the prevailing NYISO strip capacity market price.

CPA similarly supports Staff's recommendation that Con Edison be required to purchase capacity from all projects up to 5 MW UCAP. CPA recommends that if the Commission increases the size limitation on Value Stack-eligible projects, the limit of maximum UCAP sales should be similarly adjusted. In response to Staff's request for comments on whether a maximum cumulative UCAP purchase threshold should be set to avoid distorting the NYISO's UCAP strip auction price-setting process, CPA submits that Staff's concern regarding price formation is "uncompelling." CPA claims that all capacity used and sold within New York is ultimately reflected in the price formation process through bids, offers, and the operation of the demand curve, whether participation is direct or not. CPA acknowledges that there could be a situation where there could be a mismatch between Strip payments and which of the three capacity markets in which the buyback capacity effectively participates (Strip, Monthly, or Spot) in the case of customer-provided capacity that is compensated at the strip auction price while it is being reflected in the price formation process as either a load modifier or as a utility-offered sale of capacity. CPA submits that because it is within the utility's power to ensure that there is alignment (either by purchasing an appropriate amount of capacity in the Strip auction or selling an appropriate amount of capacity into the Strip auction), the pricing of the purchased capacity at zero is appropriate, given the basis on which it is required to be offered and sold through the buyback tariffs.

NY-BEST supports Staff's recommendation that Con Edison and O&R be directed to modify their respective Buyback Service tariffs. NY-BEST does not support, however, the Staff recommendation that a maximum project-level UCAP limit be set at 5 MW for purchases of capacity from technologies not eligible for the Value Stack, which it submits is unsupported in the Staff Whitepaper and may limit the ability of DERs to provide capacity to utilities.

Digital also supports Staff's recommendation, and urges that all tariffs be clarified to make clear the prices to be paid under Buyback Service for energy and capacity, as well as the requirements for both the DER and the utility to engage in the sale of energy and capacity.

The Joint Utilities propose that the recommendations in the Staff Whitepaper be clarified as follows: (1) the recommendation would not apply to those utilities with existing contracts in place to purchase UCAP from non-Value Stack eligible technologies with a capacity greater than 5 MWs; (2) the utilities' obligation to purchase UCAP from customers with generating facilities should extend only to those customers that have UCAP which meets the NYISO requirements for qualifying capacity (with the customer assuming the obligation to obtain such qualification); and, (3) customers should not be required to sell their UCAP to a utility for those facilities sized at less than 5 MWs in capacity, but rather should have the option of selling directly into the NYISO.

The Joint Utilities disagree with the recommendation that Con Edison and O&R be directed to purchase capacity at prevailing NYISO strip prices, noting that other utilities purchase capacity at spot prices. They argue that utilities should have discretion to determine the best pricing method for their customers, and that any issue regarding which approach is superior should be resolved in individual utility rate proceedings.

D. Determination

The Staff Whitepaper contains several recommendations to standardize the practices of utilities with respect to the purchase of UCAP from eligible customers through their respective Buyback Service tariffs. First, Con Edison's and O&R's tariffs include no specific tariff language granting customers the right to negotiate with these utilities for such contracts, thereby leaving it to the utilities' discretion as to whether to purchase UCAP through Buyback Service. The Commission agrees with Staff that this represents a potential barrier to DER adoption, and therefore directs Con Edison and O&R to modify their respective Buyback Service tariffs to require those companies to purchase UCAP from eligible customers at the prevailing NYISO monthly[47] market price. This is consistent with our recent Order Regarding Value Stack Compensation.[48] The Commission directs Con Edison and O&R to make the necessary tariff filings to become effective no later than July 1, 2019.

Second, the Commission shares the concern expressed in the Staff Whitepaper about the lack of consistency among the utilities' tariff provisions regarding the amount of UCAP that each utility may purchase from customers. While the Commission sees no evidence that basing buyback rate compensation on NYISO auction or spot prices would cause a market distortion, it is reasonable to set a maximum limit that utilities should purchase. Above such a limit, generators can be expected to participate in NYISO wholesale markets. The 5 MW project-level

[47] The final monthly auction price for the following month.

[48] Case 15-E-0751, supra, Order Regarding Value Stack Compensation (issued April 18, 2019).

UCAP compensation limit proposed by Staff is reasonably consistent with the maximum project size allowed under VDER and should be uniformly applied across the State. The Commission directs each of the utilities to file tariff revisions as necessary to implement this 5 MW project level UCAP compensation limit to become effective no later than July 1, 2019.

Finally, the Commission accepts the modification proposed by the Joint Utilities to exempt the UCAP purchase requirement for resources with a capacity greater than 5 MW if they are operating under existing contracts. Any such existing customers shall be grandfathered to enable such capacity purchases to continue without regard to the new 5 MW limitation.

XI. Modification of Con Edison Buyback Contract Demand Charge

A. Background

In the October 2016 Con Edison and O&R Standby/Buyback Rates Report,[49] Con Edison proposed modifying the Contract Demand Charge under its Buyback Service for customers taking service at the primary voltage level. Con Edison explained that currently Contract Demand Charges applicable to Buyback Service customers are set equal to the Contract Demand Charge under the otherwise applicable Standby Service rate and further explained that a portion of substation costs are allocated to and collected through the Contract Demand Charge for standby customers taking service at the primary voltage level.[50] Con Edison noted that it is unlikely a customer's export would place additional demand on

[49] Case 16-M-0430, Rate Design Reforms Supporting Reforming the Energy Vision, Standby Rate Matrix Study and Recommendations of Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. (filed October 7, 2016) (Con Edison and O&R Standby/Buyback Rate Report).

[50] This issue is unique to Primary Service customers, as the substation costs are allocated entirely to the Daily As-Used Demand Charge instead of the Contract Demand Charge for customers taking service at the secondary voltage level.

substation facilities. It therefore proposed to eliminate the portion of substation costs included in the Contract Demand Charge for Buyback Service customers taking service at the primary voltage level.

B. Staff Whitepaper Recommendation

The Staff Whitepaper recommends that Con Edison be directed to modify its Buyback Service Contract Demand Charge to remove the portion of primary voltage substation costs from the applicable Contract Demand Charge, consistent with Con Edison’s proposal. The Staff Whitepaper further recommends that other utilities be directed to examine the calculation of their Buyback Service Contract Demand Charge for standby customers taking service at the primary voltage level to determine whether similar modifications are necessary and, if so, to file the necessary tariff revisions to effectuate those modifications.

C. Comments

The Joint Utilities, the City, CPA, and Digital all support Staff’s recommendation for approval of Con Edison’s proposal to modify its Buyback Service tariff to remove a portion of substation costs included in the Contract Demand Charge for buyback customers taking service at the primary voltage level. The Joint Utilities note that similar changes are necessary for tariffs other than Con Edison’s.

D. Determination

The Commission agrees with Con Edison’s proposed revision to the calculation of the Contract Demand Charge under its Buyback Service for customers taking service at the primary voltage level. However, since the application of the ACOS methodology could have an impact on the resulting rate, Con Edison is directed to include this revision as part of the September 4, 2019 draft tariff filing. The other utilities should also review their calculation of Contract Demand Charge for Buyback Service, determine whether a similar change is necessary, and include that change in their September 4, 2019 draft tariff filing if so.

XII. Grid Access Demand Charges for Energy Storage Systems

A. Background

On May 22, 2018, Staff filed the Value Stack Expansion Whitepaper,[51] which proposed, among other things, that the Standby and Buyback Service provisions that would otherwise apply to technologies that are eligible for Value Stack compensation, but not eligible for NEM, would continue to apply, including Contract Demand charges to recover local system costs, with the exception that compensation for hourly net injections would be made based on the Value Stack methodology instead of the existing Buyback Service compensation. Among the technologies which would be newly-eligible for Value Stack compensation were energy storage technologies, including stand-alone systems, energy storage systems paired with consumption load, and regenerative braking systems.

While many respondents to the Value Stack Expansion Whitepaper supported the Staff proposal, several commenters expressed concerns. Among the concerns raised by stakeholders were that applying Standby and Buyback Service rates to newly-eligible Value Stack technologies could create a barrier to these technologies' adoption by disadvantaging these technologies as compared to already eligible technologies and that the application of Standby and Buyback Service Contract Demand charges to these technologies should be studied further. Commenters suggested that newly-eligible Value Stack technologies be allowed to select either Standby Service or

[51] Case 15-E-0751, Staff Proposal on Value Stack Eligibility Expansion (filed May 22, 2018) (Value Stack Expansion Whitepaper).

standard service and that current technology-based exemptions to the Standby Service be extended to include these technologies.

While the Commission was still considering the Value Stack Expansion Whitepaper, Staff and the New York State Energy Research and Development Authority (NYSERDA) jointly issued the Storage Roadmap.[52] The Storage Roadmap recommended that the Commission implement Staff's recommendations in the Value Stack Expansion Whitepaper with regard to the application of Standby and Buyback Service Contract Demand rates to energy storage projects. However, it also noted that the impacts and outcomes of this approach should be examined in the context of various energy storage use cases, and requested stakeholder feedback to help develop the record for Commission decision in this regard. In particular, Staff and NYSERDA note the that FERC's Order No. 841 allows energy storage systems connected to the utility distribution system to charge at the wholesale energy market price when providing wholesale services, whereas charging for distribution services would vary depending upon the applicable distribution rates.

Responding to the Storage Roadmap recommendations, commenters suggested that more evaluation is necessary. In particular, commenters expressed concern that application of Standby and Buyback Service Contract Demand charges may reduce economic benefits of operating energy storage systems and that application of distribution-level Contract Demand charges may create a cost and pricing disparity between energy storage systems participating in the wholesale market only and those participating in distribution-level markets. Commenters suggest

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[52] Case 18-E-0130, supra, New York State Energy Storage Roadmap and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations (filed June 21, 2018) (Storage Roadmap).

that charging rates and discharging compensation be provided with specific daily, monthly, and seasonally-granular rates or, in the alternative, that energy storage providers participating in distribution-level markets only be charged the applicable wholesale energy cost plus an adder to recover fixed system costs from such customers.

Subsequent to both the Value Stack Expansion Whitepaper and the Storage Roadmap, the Commission issued its Value Stack Expansion Order.[53] In the Value Stack Expansion Order, the Commission adopted Staff's proposal to apply all provisions of existing Standby and Buyback Service to newly Value Stack-eligible technologies with the exception that net hourly injections from these technologies would be compensated using the Value Stack methodology instead of the applicable Buyback Service compensation. The Commission noted that "[s]tandby [service] rates seek to ensure that customers who generate on-site ... are charged an appropriate level to support ... the existence and maintenance of the electrical grid," and that "buyback [service] rates similarly ensure that customers who inject energy into the grid provide appropriate contributions to the maintenance of the grid."[54] Responding to stakeholders' requests that newly Value Stack-eligible technologies be offered exemptions from Standby and Buyback Service rates, the Commission stated that "[e]xempting customers from [Standby and Buyback Service] rates, and allowing them to instead remain on standard rates not designed with prosumers in mind, carries the potential of allowing those customers to

[53] Case 15-E-0751, Order on Value Stack Eligibility Expansion and Other Matters (issued September 12, 2018) (Value Stack Expansion Order).

[54] Value Stack Expansion Order, p. 18.

contribute less than the costs they cause and thereby shift costs onto other customers.”[55]

B. Staff Whitepaper Recommendation

The Staff Whitepaper recommends that the Commission continue requiring energy storage systems connected to utility distribution systems to pay the applicable delivery service rates, and, in particular, the applicable Standby and Buyback Service Contract Demand charges. As recognized by the Commission in the Value Stack Expansion Order, both Standby and Buyback Service rates are designed to ensure that the customers making use of electrical grid, both for charging and discharging purposes, pay their fair share for the costs they impose by maintaining and using a connection to the distribution system. According to Staff, the Standby and Buyback Service rates have been established in a just and reasonable manner, and allowing customers with energy storage systems to avoid such charges would unreasonably shift the cost of such customers’ local facilities to other customers.

To address the possibility that there may be instances where such charges do indeed create uneconomic conditions for energy storage systems in a way that would be unreasonable or inconsistent with the State’s policy goals, the Staff Whitepaper requested comments from stakeholders that would describe use cases or instances where application of Standby and Buyback Service charges create an unreasonable barrier to adoption of energy storage systems. The Staff Whitepaper also sought recommendations for reasonable alternatives to the existing Standby and Buyback Service charges until such time as energy storage systems under such use cases become economic.

[55] Id.

C. Comments

CEP submits that Standby Service and Buyback Service rates should not be imposed for the charging or discharging of energy storage systems. According to CEP, imposing such charges is “antithetical” to how energy storage systems are implemented in practice. CEP states that an energy storage system will be injecting power during peak times – thereby reducing stress on the system and avoiding incremental costs needed to serve all customers – and will charge during off-peak hours when there is spare capacity, thus avoiding incremental costs. CEP urges that if the Commission nonetheless chooses to impose Standby Service and Buyback Service charges on energy storage systems, such charges should apply only to charging during peak demand periods and not to injection during such periods. Digital urges the development of a special distribution rate for charging and discharging energy storage systems.

The City urges the Commission to proceed with caution in applying Standby Service and Buyback Service rates to energy storage customers, to ensure that energy storage developers are not forced to choose between minimizing Standby Service and Buyback Service charges versus taking actions based on system needs or market signals.[56] The City also notes that Buyback Service rates may prevent the storage system from rapidly injecting into the grid if needed for grid relief purposes, inasmuch as doing so could significantly increase the system’s Contract Demand. According to the City, these price signals effectively negate the beneficial qualities of energy storage.

[56] The City offers the example of a 1,000 kW capacity front-of-the-meter energy storage system that is capable of charging at a faster rate to meet system needs or market conditions, but would not do so in order to avoid dramatically increasing the storage systems’ Contract Demand.

NY-BEST makes a similar argument that Staff's recommendation would unfairly penalize storage systems for ultimately providing a beneficial service to the distribution system, due to the lack of temporal differentiation in Contract Demand charges (e.g., energy storage that charges at night and discharges during peak hours relieves stress on the network). NY-BEST recommends that, for energy storage resources, the Contract Demand Charge should be set at zero or, alternatively, that the times the Contract Demand Charge would apply should be limited (e.g., apply the Contract Demand charge to charging during the Super-Peak period and not apply to discharging (i.e., exporting energy).

NY-BEST makes the further point that requiring energy storage systems to pay both the applicable delivery service rates and the applicable Standby Service and Buyback Service Contract Demand charges would result in storage essentially being charged twice for the same service and thus bearing additional costs that would negatively impact the economic proposition for storage. According to NY-BEST, the addition of storage at a site would require the project to bear local upgrade costs through the interconnection process. NY-BEST submits that it is unlikely that there are further local costs unique to exports beyond those captured in the interconnection process. The City makes the same assertion with respect to Grid Access charges for Buyback Service rates generally, given that on-site generators are already required under the Commission's Standardized Interconnection Requirements to pay significant interconnection fees to cover any utility system upgrades and equipment that is necessary for the grid to accommodate their projects.

The Joint Utilities submit that Standby Service and Buyback Service rates, which are determined to be just and reasonable, should not be changed simply in order to support certain business cases. They argue that revising these rates in a manner designed to make specific energy storage use cases economic is not a technology-neutral approach, in violation of one of the Commission’s core rate design principles. They submit that the stakeholder process contemplated in the Staff Whitepaper is unnecessary and should not be implemented. CPA is also uncertain that circumstances exist that would justify what it submits would be the subsidization of customers with energy storage systems by customers without.

D. Determination

As noted above, the Commission’s recent Energy Storage Order commented on the ability of standby rates to align individual customers’ contribution to system costs with the rates such customers pay, thereby resulting in improved price signals to those customers.[57] The accuracy of these price signals will be improved with the utilities application of the ACOS methodology and offering more granular Daily As-Used Demand Charges with Off-Peak, On-Peak, and Super-Peak charge components, as the Commission is requiring as part of this Order. These improvements address the circumstances identified by the City, the CEP, and NY-BEST with respect to ensuring that storage systems are compensated for providing beneficial services to the distribution system.

With respect to NY-BEST’s and the City’s assertion regarding the potential duplication in costs borne by customers paying both interconnection costs as part of the Standardized Interconnection Requirements process and local costs through Contract Demand Charges under Buyback Service rates, the Commission recognizes that both these charges are designed to be

[57] Case 18-E-0130, supra, Energy Storage Order, p. 15.

specific to individual customers, and that interconnection costs may be significant. In actual practice, however, the costs related to interconnection and costs recovered through Contract Demand Charges are separate and distinct.

Interconnection charges are generally developed to recover the costs of utility system upgrades and protection equipment needed to ensure and maintain safety and reliability. These costs are dependent upon each individual customer and installation. These upgrades can be located on any part of the utility system, and thus the costs may include both recovery for elements that are considered shared and/or local costs. Contract Demand Charges, as described earlier, are designed to recover those embedded costs of the utility system that are considered local to the customer.[58] In short, the Interconnection Charge recovers the costs of additional specific pieces of equipment needed to safely interconnect a customer's DER to the system, whereas the Contract Demand Charge recovers the local costs of the embedded system itself, which are applied to customers based on their individual Contract Demands. Contract Demand Charges should therefore continue to be applied to energy storage systems and more generally to all types of DER taking service under Standby and Buyback Service rates.

The Commission accepts the recommendation in the Staff Whitepaper to continue to require energy storage systems connected to utility distribution systems to pay the applicable delivery service rates and, in particular, the applicable Standby and Buyback Service Contract Demand charges.

[58] In addition, to the extent that the Customer Charge does not fully recover all of the customer-related costs for a service classification, the remaining revenues are frequently recovered through other charges. Accordingly, the Contract Demand Charge may also include a portion of these otherwise-unrecovered customer-related costs.

XIII. Implementation Issues

As noted by the Joint Utilities, implementation of many of the recommendations in this Order will require modification to utility billing systems. The effective dates established in this Order are intended to provide the utilities with sufficient time to make the necessary billing system changes. With respect to the timely recognition of all associated costs in rates, the Commission expects the utilities to make proposals, as necessary, for cost recovery either in the context of ongoing rate cases or through a request for deferred accounting treatment if not already provided for in rates, assuming such costs are material to warrant such treatment.

With respect to the tariff changes directed in this Order, the requirement for newspaper publication is waived given the limited applicability of those changes and the substantial public process that led to this Order.

XIV. Reporting Requirements

As discussed above, the Commission directs utilities to monitor and report on the use of opt-in standby rates. Specifically, the Commission is requiring each utility to report no less often than annually on the number of customers within each service classification migrating to optional Standby Service rates, and the associated bill impacts on non-participating customers within each such service classification. Such reporting shall include “shadow billing” for each customer (i.e., providing a comparison of charges to customers under their standard service classification versus the optional Standby Service rate). Finally, the Commission directs the utilities to provide notice to Staff in the event more than two percent (2%) of the aggregate load within in a single service classification migrates to optional Standby Service rates.

CONCLUSION

The modifications to Standby Service and Buyback Service rates that are adopted in this Order will result in rates that more accurately align individual customers' contribution to system costs with the rates such customers pay, thereby sending improved price signals to those customers. Customers currently served under Standby Service and Buyback Service rates will have an increased ability to manage their bills and those bills will more accurately reflect the effects of those customers' usage. In addition, the expanded availability of Standby Service rates as optional rates adopted in this Order will allow a broader range of customers to take advantage of the more precise price signals provided by these rates. Customers interested in managing their load to take advantage of these rates will be able to lower their own bills by reducing the costs they impose on the utility system, avoiding unfair cost shifts.

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 & Rockland Utilities, Inc., and Rochester Gas & Electric Corporation are directed to file, in conformance with the discussion in the body of this Order, tariff leaves implementing the eligibility of customers of demand-metered service classes for opt-in participation in Standby Service rates on not less than 20 days' notice to become effective on July 1, 2019.

2. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Orange & Rockland Utilities, Inc.

and Rochester Gas & Electric Corporation are directed to develop and file, in conformance with the discussion in the body of this Order, Allocated Embedded Cost of Service (ACOS) studies by September 4, 2019.

3. 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 & Rockland Utilities, Inc., and Rochester Gas & Electric Corporation are directed to file by September 4, 2019, in conformance with the discussion in the body of this Order and based on each utility's respective ACOS study, draft tariff revisions for redesigned mass market Standby Service rates including Contract Demand Charges based on individual customers' maximum demand and Daily As-Used Demand Charges based on daily maximum on-peak demands.

4. 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 & Rockland Utilities, Inc., and Rochester Gas & Electric Corporation shall report each year by March 31, in conformance with the discussion in the body of this Order, on the number of customers within each service classification that are participating in optional Standby Service rates during the prior year and the bill impacts on non-participating customers within each such service classification. In addition to this annual reporting requirement, each utility shall provide notice to the Commission in the event more than two percent of the aggregate load within in a single service classification migrates to optional Standby Service rates.

5. 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 & Rockland Utilities, Inc., and Rochester Gas & Electric Corporation are directed to file by September 4, 2019, in conformance with the discussion in the body of this Order and based on each utility's respective ACOS study, draft tariff revisions for Standby Service and Buyback Service rates that: (a) reflect the results of the ACOS studies; (b) include Daily As-Used Demand Charges with Off-Peak, On-Peak, and Super-Peak charge components during the summer period; (d) include a Multi-Party Campus Offset Tariff, for utilities that have not already had a such a tariff approved; (d) include, as part of Buyback Service for dual service customers, an incremental Contract Demand Charges for generator kW capacity greater than the customer's maximum annual usage demand; and, (e) revise the Buyback Service Contract Demand Charge for customers taking service at the primary voltage level. Niagara Mohawk Power Corporation d/b/a National Grid's filing regarding Buyback Service rates shall also include a Customer Charge and a Contract Demand Charge for buyback-only customers.

6. 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 & Rockland Utilities, Inc., and Rochester Gas & Electric Corporation are directed to file, in conformance with the discussion in the body of this Order, tariff leaves restricting eligibility for the Reliability Credit to exclude customers' distributed energy resources that receive Value Stack compensation for exports to the system, on not less than 20 days' notice to become effective on July 1, 2019.

7. Consolidated Edison Company of New York, Inc. and Orange & Rockland Utilities, Inc. are directed to file, in conformance with the discussion in the body of this Order, tariff leaves requiring them to purchase Unforced Capacity

(UCAP) from eligible Buyback Service customers at the prevailing NYISO monthly market price on not less than 20 days' notice to become effective on July 1, 2019.

8. 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 & Rockland Utilities, Inc., and Rochester Gas & Electric Corporation are directed to file, in conformance with the discussion in the body of this Order, tariff leaves implementing a maximum project-level UCAP limit of 5 MW for purchases of capacity through Buyback Service, except where an existing contract provides for the purchase of UCAP from a resource with a capacity greater than 5 MW, on not less than 20 days' notice to become effective on July 1, 2019.

9. The requirements of Public Service Law §66(12)(b) and 16 NYCRR §720-8.1, related to newspaper publication of the tariff amendments described by Ordering Clauses 1, 6, 7, and 8, are waived.

10. 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.

11. This proceeding is continued.

By the Commission,

(SIGNED)

KATHLEEN H. BURGESS
Secretary

APPENDIX 1

Standby Service Daily As-Used Demand Elements at NYS Utilities

Utility	Service Classification	Daily As-Used Demand			Seasonal Differential
		On-Peak	Super-Peak	Off-peak	
Central Hudson	SC 14	7 AM - 11 PM, weekdays	N/A	All other hours	No
Con Edison	Specific Rates of SC 5, 8, 9, 12, and 13	8 AM - 10 PM, weekdays, non-holiday	8 AM - 6 PM Weekdays, non-holiday	All other hours	Yes
NYSEG	SC 11	7 AM - 10 PM, weekdays, non-holiday	N/A	All other hours	No
Niagara Mohawk	SC 7	8 AM - 10 PM, weekdays, non-holiday	N/A	All other hours	No
O&R	SC 25	8 AM - 11 PM, weekdays, non-holiday	N/A	All other hours	Yes
RG&E	SC 14	7 AM - 11 PM, weekdays	N/A	All other hours	No