STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 22-E-0236 – Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structures for Commercial Electric Vehicle Charging.

ORDER ESTABLISHING FRAMEWORK FOR ALTERNATIVES TO TRADITIONAL DEMAND-BASED RATE STRUCTURES

Issued and Effective: January 19, 2023

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At a session of the Public Service Commission held in the City of Albany on January 19, 2023

COMMISSIONERS PRESENT:

Rory M. Christian, Chair
Diane X. Burman, concurring
James S. Alesi
Tracey A. Edwards
John B. Howard
David J. Valesky
John B. Maggiore

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BY THE COMMISSION:

INTRODUCTION

This Order implements alternative solutions to the traditional demand-based rate structure for commercial electric vehicle charging use cases, as required by recently enacted legislation. Effective December 31, 2021, Governor Hochul enacted Public Service Law (PSL) §66-s Electric vehicle charging; commercial tariff. Through PSL §66-s, the Public Service Commission (Commission) was instructed to commence a proceeding to establish a commercial tariff utilizing alternatives to traditional demand-based rate structures, other operating cost relief mechanisms, or a combination thereof to facilitate faster charging for eligible light duty, heavy duty, and fleet vehicles (collectively, Solutions). In response, the

Commission instituted this proceeding. On April 21, 2022, the Commission issued a Notice Soliciting Comments (Notice), requesting comments regarding the potential impacts to ratepayers from adoption of a rule change that would eliminate or change the traditional demand-based rate for commercial purposes and responses to enumerated questions.[1]

Informed by both the comments received in response to the Notice and a report by the New York State Energy Research and Development Authority (NYSERDA) and a consultant, Guidehouse, the Department of Public Service Staff (DPS Staff) issued the Department of Public Service Whitepaper Regarding Alternatives to the Traditional Demand Charge for Commercial Customer Electric Vehicle Charging (DPS Staff Whitepaper) on September 26, 2022. The DPS Staff Whitepaper proposed two Solutions: (1) a Commercial Managed Charging Program; and (2) an Electric Vehicle (EV) Phase-In Rate. Following the issuance of the DPS Staff Whitepaper, Stakeholders provided comments on the proposed Solutions.

By this Order, the Commission adopts a suite of Immediate Solutions differentiated by utility service territory and EV charging use case, and the EV Phase-In Rate Solution, with modifications. As an Immediate Solution, this Order directs all of the New York State investor-owned electric utilities (the Utilities) to implement a Demand Charge Rebate that provides a 50 percent rebate against traditional demand

[1] Case 22-E-0236, Notice Soliciting Comments (issued April 21, 2022).

charges for public Direct Current Fast Charging (DCFC) sites.[2] This Order extends the same rebate to all commercial EV charging use cases in Central Hudson, National Grid, NYSEG, and RG&E service territories, and implements a Commercial Managed Charging Program with use-case-specific adders for transit charging and other EV charging use cases as needed in the Con Edison and O&R service territories. This Order requires Central Hudson, National Grid, NYSEG, and RG&E to develop and file Commercial Managed Charging Program proposals within 180 days of the effective date of this Order.

As a Near-term Solution, this Order approves the EV Phase-In Rate Solution recommended in the DPS Staff Whitepaper, with modifications, and requires the Utilities to develop and file proposals to implement such tariff within 180 days of the effective date of this Order. The Demand Charge Rebate and use-case-specific adders will be replaced by the EV Phase-In Rate Solution, once the Near-term Solution is available. This Order also directs the Utilities to implement standby rate exemptions for customers that install energy storage systems to help manage the demand of their EV charging load. Finally, this Order establishes semi-annual reporting requirements and a biennial review process to ensure that the operating cost relief programs and tariffs approved in this Order continue to operate effectively. With these tariff options and programs, the Commission complies with the requirements of PSL §66-s, and will greatly diminish the barrier posed by the traditional demand charge to EV charging deployment in New York.

[2] The 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 (National Grid); Orange and Rockland Utilities, Inc. (O&R); and Rochester Gas and Electric Corporation (RG&E).

DPS STAFF WHITEPAPER

Beginning with an explanation of traditional demand charges, the DPS Staff Whitepaper walked through the background of the application of demand charges, including challenges that commercial EV charging customers faced through the application of the traditional demand charge.[3] In light of these challenges, and the directive in PSL §66-s, the DPS Staff Whitepaper proposed two alternative Solutions to the traditional demand charge for commercial EV charging customers: 1) a commercial managed charging program for all utility service territories, for immediate implementation; and 2) an EV Phase-In Rate Design for all utility service territories, for near-term implementation.[4] Additionally, the DPS Staff Whitepaper proposed eliminating the DCFC Per-Plug Incentive (PPI) Program and repurposing the funds to provide incentives for demand management technologies through the commercial managed charging program.

In order to ensure that the proposed Solutions were actually providing the relief required, the DPS Staff Whitepaper proposed a multi-step review process, including quarterly reports, with enumerated information to be included in the reports.[5] Additionally, the DPS Staff Whitepaper suggested a biennial review process, including a public stakeholder notice and comment period.[6]

In addition, in a notice issued on October 7, 2022, the public was informed of a stakeholder meeting, which DPS Staff held on November 4, 2022. During the stakeholder meeting,

[3] Case 22-E-0236, supra, DPS Staff Whitepaper, p. 4.

[4] DPS Staff Whitepaper, p. 31.

[5] DPS Staff Whitepaper, p. 47.

[6] DPS Staff Whitepaper, p. 48.

DPS Staff, NYSERDA, Guidehouse, and Electrify America gave presentations discussing and clarifying matters in the DPS Staff Whitepaper.[7]

NOTICE OF PROPOSED RULE MAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rule Making regarding the DPS Staff Whitepaper was published in the State Register on October 5, 2022 [SAPA No. 22-E-0236SP1]. The time for submission of comments pursuant to the Notice expired on December 5, 2022. The comments received are addressed below.

COMMENTS

Twenty sets of comments were submitted by a range of stakeholders representing public charging developers, commercial fleet developers, transit authorities, municipalities, utilities, and environmental groups. Specifically, comments were received from Advanced Energy Economy and the Alliance for Clean Energy New York (AEE and ACE-NY); the Alliance for Transportation Electrification (ATE); BP Pulse Fleet; CALSTART; the City of New York (City); Environmental Defense Fund (EDF); FreeWire Technologies (FreeWire); Independent Petroleum Marketers Association (IPMA); Electrify America, LLC, Chargepoint, Inc., EVgo Services, LLC, and Tesla, Inc., collectively as the Joint EV Industry Parties (JEVIP); the Utilities (also referred to as the Joint Utilities or JU) and PSEG Long Island; the Metropolitan Transit Authority (MTA); Natural Resources Defense Fund and Sierra Club (NRDC and Sierra Club); the New York Battery and Energy Storage Technology

[7] Copies of these presentations, as well as a link to a recording of the entire stakeholder session, are available in the Document Matter Management system.

Consortium (NY-BEST); the New York League of Conservation Voters and Environmental Advocates of New York (League of Conservation Voters); New York Power Authority (NYPA); Revel; TeraWatt Infrastructure (TeraWatt); Uber Technologies, Inc. (Uber); the Vehicle-Grid Integration Council (VGIC); and WattTime. These comments are summarized in detail in Appendix D and addressed below in relevant parts of the Discussion.

LEGAL AUTHORITY

In carrying out its responsibilities, the Commission has broad discretion and judgment in choosing the means of achieving statutory mandates and has the authority to adopt different methodologies or combinations of methodologies in balancing ratepayer and investor interests.[8] PSL §5 grants the Commission authority to direct utilities to "formulate and carry out long-range programs, individually or cooperatively, with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources."

The Commission has further authority under PSL §66(2)to "examine or investigate the methods employed by ... persons, corporations and municipalities in manufacturing, distributing and supplying ... electricity ... and have power to order such reasonable improvements as will best promote the public interest, preserve the public health and protect those using such ... electricity."

Moreover, the Commission has authority pursuant to PSL §66(14) "to require each ... electric corporation to establish classifications of service based upon the quantity used, the time when used, the purpose for which used, the duration of use

[8] Multiple Intervenors v. Public Service Commission of the State of New York, 166 A.D.2d 140, 143 (3d Dept. 1991).

and upon any other reasonable consideration, and to establish in connection therewith just and reasonable graduated rates and charges; and ... to require such changes in such classifications, rates and charges as [is] ... just and reasonable ... ."

Pursuant to PSL §66-s, the Commission was required to commence this proceeding to "establish a commercial tariff utilizing alternatives to traditional demand-based rate structures, other operating cost relief mechanisms, or a combination thereof (collectively, "solutions") to facilitate faster charging for eligible light duty, heavy duty, and fleet electric vehicles." The actions taken herein with respect to the alternative Solutions to the traditional demand-based rates fall within this legal authority and are designed to support long-range program goals economically and efficiently, support public health and safety, preserve environmental values, and conserve natural resources.

DISCUSSION

By this Order, the Commission takes decisive action, in accordance with the requirements of PSL §66-s, to meaningfully decrease the operating cost barrier to rapid deployment of commercial EV charging stations posed by traditional demand charges. This Order approves two sets of Immediate Solutions - one set for the Upstate Utilities (i.e., Central Hudson, National Grid, NYSEG, and RG&E) and one set for the Downstate Utilities (i.e., Con Edison, and O&R). With the two sets of Immediate Solutions, the Commission recognizes the differing grid conditions between the Upstate and Downstate Utilities and, therefore, differing ability to implement Solutions swiftly, effectively, and successfully. While the Commission approves different Immediate Solutions, however, we approve the same Near-Term Solution, the EV Phase-In Rate Solution, for all of the Utilities across New York State.[9]

For Immediate Solutions in the Upstate Utilities' service territories, this Order approves the 50 percent Demand Charge Rebate proposed by the Upstate Utilities in their comments, with modification to allow the Demand Charge Rebate to be applied without requiring participants to separately meter EV charging load. The Demand Charge Rebate will be offered to EV charging customers until the EV Phase-In Rate Solution becomes available for customer participation. To ensure that customers with intermingled EV charging load and other site load are eligible to participate in the Demand Charge Rebate, and to set how much of such customers' total demand is subject to the rebate, this Order requires that the Upstate Utilities compute a Charging Ratio based on the ratio of EV charging capability to maximum possible customer demand. This Order also requires the Upstate Utilities to immediately begin work to develop a Commercial Managed Charging Program (CMCP), and submit proposals to implement such programs within 180 days of the effective date of this Order.

For Immediate Solutions in the Downstate Utilities' service territories for most EV charging use-cases, this Order adopts the DPS Staff Whitepaper's proposal to implement a CMCP with use-case-specific adder incentives. For the public DCFC use case, specifically, this Order directs the Downstate Utilities to implement a 50 percent Demand Charge Rebate, with the same requirements to establish a Charging Ratio to determine customer eligibility and proportion of demand that will be

[9] While the Commission appreciates PSEG-LI's input as part of the JU's comments, this Order focuses exclusively on the six investor-owned electric utilities under the Commission's direct jurisdiction.

subject to the rebate. The use-case-specific adders and Demand Charge Rebate will be offered to EV charging customers until the EV Phase-In Rate Solution becomes available for customer participation.

As the Near-Term Solution for both the Upstate Utilities and the Downstate Utilities, this Order adopts the EV Phase-In Rate Solution recommended in the DPS Staff Whitepaper, with modifications. This Order approves the three graduations recommended in the DPS Staff Whitepaper, and implements a fourth graduation from annual load factors of greater than 20 percent to less than 25 percent to help ease the transition and avoid abrupt changes in price-signals as high load factor customers phase out of eligibility. This Order also provides flexibility for how the Utilities design the Time-of-Use (TOU) Energy Charge component of the EV Phase-In Rate Solution, as well as the proportion of revenues collected through the TOU Energy Charge and Traditional Demand Charge in most of the EV Phase-In Rate graduations. This Order adopts the Charging Ratio to determine eligibility for customers that intermingle EV charging load and other site loads, and modifies the DPS Staff Whitepaper's recommended schedule for determining annual load factors to a semi-annual cadence that will result in no more than two changes in graduation for participants per year.

This Order approves the biennial review process recommended in the DPS Staff Whitepaper, but modifies its recommended reporting requirements. Specifically, this Order requires several additional pieces of aggregated data regarding Solution participant energy use during off-peak, on-peak, and super-peak periods, but decreases the frequency of data reporting to the Commission to a semi-annual cadence to ease some of the burden of data reporting on Solution participants.

While this Order establishes a framework for implementing the Immediate Solutions and the EV Phase-In Rate Solution, there are many details which must be developed as part of utility-specific compliance and tariff filings. Specifically, the Utilities are directed to make two sets of filings. First, the Utilities shall make a filing 60 days after the effective date of this Order, as required under PSL §66-s, to implement the Immediate Solutions approved in this Order (Immediate Solution Filings). The Commission will then take public comment on the Utilities' Immediate Solution filings, and anticipates issuing an Order finalizing those Solutions and opening such Solutions for participation during the summer of 2023.

Second, the Utilities shall make a filing 180 days after the effective date of this Order, as recommended in the DPS Staff Whitepaper, to propose specific rates and other details related to the EV Phase-In Rate Solution (EV Phase-In Rate Filing). The Commission will take public comment on the Utilities' EV Phase-In Rate Filings, and anticipates issuing an Order on such filings in the fourth quarter of 2023. While the Commission is hopeful these filings can be handled expeditiously to allow customers to begin taking service under the EV Phase-In Rates as quickly as possible, it is important to recognize there may be additional time necessary to fully implement the EV Phase-In Rate Solution as a rate design-based tariff in comparison to an off-bill program.

<u>Immediate Solutions</u>

As noted by FreeWire, NY-BEST, and Revel, the demand charge is a powerful incentive for customers to manage the demand they impose on the electrical grid. Blunting that price signal, while advantageous from the perspective of helping to reduce operating costs for commercial EV charging customers, also reduces the incentive for customers to manage their demand. The Utilities may have to build more infrastructure to meet the potentially higher, unmanaged level of demand in comparison to well-managed EV charging demands, and thus customers would likely pay higher rates in the long term if incentives to manage demand are not maintained. It is reasonable, therefore, to establish incentives for demand management technologies alongside the operating cost relief measures approved in this Order. Although the Upstate Utilities', ATE's, and the JEVIP's proposals to use the PPI Program funding to defray the costs of a 50 percent rebate in demand charges for certain customers is attractive, PPI Program funds are better used as recommended in the DPS Staff Whitepaper.

Therefore, the Commission concurs with the DPS Staff Whitepaper's recommendation to cancel the DCFC PPI Program, and redeploy the previously-accumulated and unspent collections from the program to fund a new program to incentivize EV charging demand management technologies.[10] This program shall, at a minimum, provide incentives for on-site energy storage, energy storage integrated directly into charging equipment, and advanced load management technologies and software.[11] The Commission finds that an upfront incentive is the most beneficial format for the demand management technologies incentive. An upfront incentive aligns with the usual timing of customers' decisions to install load management technologies before a charging station goes online, and other incentives

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[10] These incentives should be deployed either as part of the CMCP in the Downstate Utilities' service territories, or as a separate incentive program in the Upstate Utilities' service territories.

[11] Other forms of demand management technologies not enumerated here will be eligible if recommended by the utilities or other stakeholders and subsequently approved by the Commission.

available through the CMCP, if applicable, provide for effective ongoing incentives to make best use of such technology.

The Commission also concurs with the DPS Staff Whitepaper's recommendation, and numerous supportive comments, to allow current PPI Program participants a one-time option to either continue participating in the PPI Program for the remainder of their seven-year period, or to switch to begin participation in the applicable Immediate Solution available in their service territory, as discussed in greater detail below. Existing program participants will be given at least 60 days to choose between these programmatic options. The Utilities are directed to develop plans for deploying these funds as part of their 60-day Immediate Solution Filings.

The Commission approves the Upstate Utilities' proposal to implement an off-bill 50 percent Demand Charge Rebate as the immediate solution in their respective service territories, with modification. While the Commission would prefer a more finely-tuned incentive program for many EV charging use cases in order to provide incentives toward shifting charging away from peak periods and toward off-peak periods, to the extent that customers are able to respond to such price signals, there is little other choice given the Upstate Utilities' inability to implement a program such as the CMCP within a reasonable timeframe as, unlike O&R and Con Edison, they are not building on the framework of the existing SmartCharge managed charging programs.

The 50 percent Demand Charge Rebate has a proven track record in other states, and has garnered broad support from a wide variety of stakeholders, including environmentalists, EV charging station developers, transit and fleet groups, as well as the Upstate Utilities. Further, as discussed below, the 50 percent Demand Charge Rebate is the Commission's preferred

Solution for the public DCFC use case. Therefore, as the preferred Solution for public DCFC charging, and in the absence of other preferable viable Solutions for other use cases, the Commission adopts the Upstate Utilities', JEVIP's, and numerous other groups' recommendations to establish a 50 percent Demand Charge Rebate in the Upstate Utilities' service territories.

The Demand Charge Rebate shall only be available in each utility service territory until the EV Phase-In Rate Solution is available for customer participation in such service territory. This requirement is similar to the Whitepaper's recommendation that use-case-specific adders of the CMCP be phased out once the EV Phase-In Rate Solution is available, and has garnered support from numerous stakeholders. Specifically, AEE and ACE-NY, ATE, CALSTART, FreeWire, the JEVIP, the JU, the League of Conservation Voters, and Uber, each either note specific support for the Whitepaper's proposal to eliminate use-case-specific adders upon availability of the EV Phase-In Rate Solution or include a similar feature in their own proposals, such as the Demand Charge Rebate, which would be eliminated once the EV Phase-In Rate Solution is available. The Commission agrees with the Whitepaper recommendation and Stakeholder input, and finds this transition reasonable and necessary.

Where the Commission will modify the Upstate Utilities' proposed Demand Charge Rebate, however, is with respect to that proposal's reliance on separately metered EV charging load. Many commenters point to the PPI Program as a series of foibles which future programs would do well to avoid, including onerous data reporting requirements, and discounts which decrease on a set schedule by calendar year instead of based on actual economic conditions experienced by charging stations, among other issues. While not the only reason that the PPI Program has proven to be unpopular, the Commission understands that the PPI Program's requirement that EV charging load be separately metered is a major contributor toward the program's unpopularity. The Commission takes the lessons learned from the PPI Program to heart, and will not, therefore, implement similarly onerous eligibility requirements which might undercut the Demand Charge Rebate.

We note that the JU claims that separately metering EV charging load is necessary in either the Upstate Utilities' Demand Charge Rebate or the EV Phase-In Rate Solution, while the Upstate Utilities argue that disaggregating EV charging load from other site load is technically infeasible in their service territories, and the Downstate Utilities note that such disaggregation is feasible but administratively burdensome. The JU appear to envision a process by which the utility must frequently compute the ratio of EV charging load to other non-EV charging site load; however, a more simple and straightforward methodology, which accomplishes the same goal without relying on infeasible or burdensome ongoing processes, is available. To determine eligibility for participation in the Demand Charge Rebate, a utility will compute the ratio of a customer's EV charging capacity and the customer's maximum demand from all on-site loads, including EV charging, or Charging Ratio. The EV charging capacity used in the Charging Ratio calculation will be the lesser of the sum of the nameplate charging capacity of each charger and the maximum simultaneous charging capacity, to the extent that there is a difference between the two.[12] The customer's maximum demand is typically reported in a customer's Load Letter which is generated during the interconnection process with the utility. Customers with a Charging Ratio of 50 percent or more shall be eligible to participate in the Demand Charge Rebate. The Utilities shall also allow customers to participate using separately-metered EV charging load.[13]

In the JU's comments, the Downstate Utilities compute the potential cost shift of the EV Phase-In Rate Solution, noting that the actual cost shift could be as much as double their stated figures, implicitly warning about the potential to incentivize non-EV charging load if the Commission does not impose a requirement that EV charging load be separately metered as a condition for participating in the EV Phase-In Rate Solution. The Commission is indeed concerned with the potential that non-EV-charging load will receive unintended subsidies from the Demand Charge Rebate or EV Phase-In Rate Solution, as providing such benefit is neither the focus of PSL §66-s nor the Commission's intention in this Order.

However, numerous stakeholders point to the Electric Vehicle Charging Distribution Demand Charge Credit approved by the Maryland Public Service Commission (Maryland EV Credit) as a

[12] Customers may choose to install multiple EV chargers of higher charging capacity than the site is able to provide simultaneously. As with the Maryland EV Credit, customers shall provide relevant information upon application and may self-attest to the EV charging capacity during the application process. Customers who are found to have inaccurately reported the EV charging capacity during the application process may be subject to re-evaluation of the Charging Ratio and program eligibility.

[13] A customer that separately meters their EV charging load shall be considered to have a Charging Ratio of 100 percent, even if there is some insubstantial amount of ancillary load required.

model that New York might follow.[14] The Maryland EV Credit does not require that EV charging loads be separately metered, and also stipulates that credits against the demand charge would only be applied based on the portion of the demand charge resulting EV charging.[15] The Commission finds the arrangement pioneered by the Maryland EV Credit to be advantageous, as it would allow customers to receive Demand Charge Rebates without the need to separately meter EV charging load and while also diminishing the possibility that non-EV-charging load will benefit from this program.

As with the eligibility requirements discussed above, the Utilities need not implement a complex, questionably feasible, and likely burdensome methodology for determining the proportion of a customer's monthly demand that the 50 percent Demand Charge Rebate will apply to. The same Charging Ratio used to determine a customer's eligibility to participate in the Demand Charge Rebate shall be used to determine the amount of proportion of a customer's demand kW the 50 percent rebate will apply to.[16] Examples of how the Utilities shall determine both a customer's eligibility for the Demand Charge Rebate and the proportion of demand that will be discounted are provided in Appendix C.

The Commission finds that the Upstate Utilities' proposal with respect to recovery of Demand Charge Rebate costs

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[14] Public Service Commission of Maryland, Case 9478, In the Matter of the Petition of the Electric Vehicle Work Group for Implementation of a Statewide Electric Vehicle Portfolio, Order No. 88997, (issued January 14, 2019), p. 59.

[15] A relevant selection of the tariff of Baltimore Gas and Electric Corporation demonstrating operation of the Maryland EV Credit is included in Appendix B.

[16] Customers that separately meter their EV load would receive a discount on the entire amount of billed demand, however, such a metering arrangement is not necessary to participate.

requires modification. In their comments, the Upstate Utilities propose to defer Demand Charge Rebate costs, amortize such costs over a five-year period, and recover the annual portion of such costs through a surcharge mechanism, but did not propose a specific method for allocating Demand Charge Rebate costs among service classes or whether recovery would be through per-kW or per-kWh charges. A more reasonable methodology would recover Demand Charge Rebate costs from all delivery customers on a one-year lag basis through an existing surcharge mechanism, with costs allocated among service classes using the transmission and distribution revenues allocator, recovered on a per-kW basis for demand-billed customers and on a per-kWh basis for non-demand-billed customers. A one-year lag in this instance approximates the operation of the Revenue Decoupling Mechanism, and our determination to allocate costs among service classes using the transmission and distribution revenues allocator reflects the fact that all customers will benefit from the environmental and societal benefits of the transition to electric vehicles which this Order seeks to accelerate.

The Upstate Utilities are directed to develop and file an Implementation Plan detailing how the 50 percent Demand Charge Rebate will be operated, including the specific mechanism for providing the rebate to customers, accounting details regarding how the expenditures will be tracked, and details regarding the surcharge cost recovery mechanism, as well as any necessary tariff leaves or revisions in draft format needed to implement such, as part of their 60-day Immediate Solutions Filing.

Although the Commission recognizes that the Upstate Utilities are unlikely to be able to develop a CMCP as the primary Solution in a reasonable timeframe, the Upstate Utilities will still be expected to develop and implement a CMCP to operate alongside other Solutions approved in this Order, and to begin such work expeditiously. At the very latest, the Commission expects the Upstate Utilities to have a fully-implemented CMCP no later than the go-live date for the EV Phase-In Rate, as discussed in greater detail below, however, a faster implementation period would be preferable. To that end, the Upstate Utilities shall develop and propose a CMCP, consistent with the CMCP approved for the Downstate Utilities as discussed in this Order, as well as any necessary tariff leaves or revisions in draft format, and file such proposal for Commission consideration within 180 days of the effective date of this Order (Commercial Managed Charging Filing).[17]

The Commission approves the DPS Staff Whitepaper's recommendation to establish a CMCP as the Immediate Solution including use case specific adders, for most, but not all, EV charging use cases in the Downstate Utilities' service territories. The Commission also approves the DPS Staff Whitepaper's recommendation to eliminate the use-case-specific adders once the EV Phase-In Rate Solution is available. The CMCP "core incentives" - that is, those incentives which will continue beyond implementation of the EV Phase-In Rate Solution – are the Peak Avoidance Incentive, based on the difference between a charger's charging capability in kW and the maximum charging demand served by that charger during a defined peak period, and the Off-Peak Charging Incentive, based on energy

[17] To be clear, while the Commercial Managed Charging Filing shall be made on the same timeline as the EV Phase-In Rate Filing directed below, the filings will be considered separate. A request for more time to propose Commercial Managed Charging Programs should not affect the timeline directed to implement the EV Phase-In Rate Solution.

used for charging during defined off-peak periods.[18] The Commission agrees with the DPS Staff Whitepaper's recommendation that the CMCP should be implemented in a manner that primarily provides operating cost relief to EV charging customers until the EV Phase-In Rate Solution is available for customer participation, and seeks to maximize cost effectiveness of the program as a secondary goal.

AEE and ACE-NY, the JEVIP, the League of Conservation Voters, NYPA, and Uber note that public DCFC stations are unable to predict when consumers will arrive to charge their vehicles, thus resulting in an inability to either plan and shift load into off-peak hours, or to avoid charging during peak periods. Further, AEE and ACE-NY, the JEVIP, the League of Conservation Voters, NYPA, and Uber note that the only feasible methods for reducing peak demand – shutting down the charging station during peak hours so that consumers cannot charge, throttling charging speeds, and thus charging demand, to a lower level, and passing along high on-peak charging prices to consumers – each negatively impact consumers EV driving experience.[19] AEE and ACE-NY, the JEVIP, the League of Conservation Voters, NYPA, and Uber argue that consumers are not yet accustomed to paying

[18] The remote location adders recommended in the Whitepaper are intended primarily for upstate locations where low population density is likely to result in longer-term low station utilization. The Commission will neither require, nor restrain, the Downstate Utilities from proposing remote location adders in their service territories. To the extent that the Downstate Utilities do propose such adders, the City's recommendation to consider charger density instead of population density is reasonable.

[19] The Commission does not presently assert jurisdiction over the prices that EV charging customers charge to consumers that use such service. See Case 13-E-0199, In the Matter of Electric Vehicle Policies, Declaratory Ruling on Jurisdiction Over Publicly Available Electric Vehicle Charging Stations (issued November 22, 2013).

variable prices based on time of day, or day of the week to fuel their vehicles, since gasoline prices do not vary in the same way as electric prices, and that reduction in EV driver experience early in the EV adoption phase will be detrimental to the rapid pace of EV adoption needed to meet New York's policy goals. In short, commenters suggest that managing charging demand is antithetical to public DCFC stations' core business model. The Commission agrees.

Because public DCFC charging is not predictable, cannot be scheduled, and often cannot be managed without impacting the EV driving experience, public DCFC stations simply cannot be expected to manage their charging at this phase in the EV adoption cycle. Public DCFC stations are unlikely to meaningfully benefit from the CMCP to the extent envisioned under PSL §66-s and, if forced to participate in the CMCP, would fundamentally receive "managed charging program" incentives without the need or expectation that they manage their charging demands. Therefore, the Commission finds that the operating cost relief measures applicable to public DCFC stations should come from a separate program, not the CMCP. Instead, the Downstate Utilities are directed to implement a 50 percent Demand Charge Rebate for public DCFC customers, identical to Demand Charge Rebate approved in this Order for the Upstate Utilities. As with the Demand Charge Rebate approved for the Upstate Utilities, this program shall be offered only until the EV Phase-In Rate Solution is available for customer participation. Similarly, the Downstate Utilities are directed to implement cost recovery for the Demand Charge Rebate for public DCFC customers in the same manner as approved for the Upstate Utilities.

Public DCFC charging customers shall still be allowed to participate in the CMCP if they so choose; however, participation will not be compulsory. To avoid potential market-distortionary effects, such as negative net charging costs due to a combination of the Demand Charge Rebate or the EV Phase-In Rate Solution, and the incentives available through the CMCP, it may be necessary to offer differing incentive payment rates under the CMCP to customers that participate in the Demand Charge Rebate or the EV Phase-In Rates in comparison to those customers that do not participate in such programs.

The Commission recognizes that participation in the CMCP may also be challenging for transit fleets, which might have to charge busses or other vehicles during peak hours. However, in considering the relative opportunities presented by the CMCP and challenges of responding to CMCP incentives, on balance the Commission finds that transit fleet charging is more aligned with the CMCP in comparison to public DCFC charging. Therefore, the Commission finds that the Demand Charge Rebate afforded to public DCFC charging is not necessary to extend to transit fleet charging; however, transit fleet charging shall receive a use case-specific adder under the CMCP.[20] The Downstate Utilities may also propose other use case-specific adders if they identify shortfalls in the CMCP core incentives to provide adequate relief from demand charges for other EV charging use cases.[21]

[20] In its comments, NYPA suggests that transit fleets would prefer a longer off-peak period for the CMCP, from at least 9 p.m. to 6 a.m. or preferably from 6 p.m. to 6 a.m. The Commission does not agree with setting the off-peak period for the CMCP to coincide with charging needs - the off-peak period provided under the CMCP should be based on cost of service principles. Incentives to help make the business case for transit fleet charging should be provided through the use-case-specific adder.

[21] In their comments, ATE and the JEVIP note that public level 2 charging use cases may require additional incentives, although they do not directly advocate for such.

The Commission approves the DPS Staff Whitepaper's recommendation to recover CMCP costs from all delivery customers on a one-year lag basis through an existing surcharge mechanism, with modification to the method that costs will be allocated among service classes, and that the CMCP costs should be recovered on a per-kW basis for demand-billed customers and on a per-kWh basis for non-demand-billed customers. Specifically, instead of the DPS Staff Whitepaper's recommendation to allocate CMCP costs to service classes based on each service classes' contribution to coincident peak, the Commission finds the JU's proposal to allocate such costs using a transmission and delivery revenues allocator to better align cost recovery of the CMCP with the benefits created through participation in the CMCP. A Coincident Peak-based allocation would match only a portion of the benefits created through participation in the CMCP related to demand reductions at the coincident peak hour. However, it would not match the program's other focus of encouraging off-peak charging, which has environmental benefits more closely related to the energy used at different times of day, and future reductions in other distribution infrastructure more driven by non-coincident peak demands in comparison to coincident peaks.

While the Commission finds that the JU's proposal to amortize CMCP program costs over a multi-year period has an advantageous effect of smoothing out potential bill impacts associated with recovery of CMCP costs, the JU's argument that CMCP costs should better match the typical useful life of distribution infrastructure avoided is not compelling. Cost recovery on a one-year lag, as recommended in the DPS Staff Whitepaper, is aligned with cost recovery of demand response programs, which are premised on avoidance of hypothetical infrastructure needed sometime in the future if demand is not reduced during present peak period. The JU’s proposal for a multi-year cost recovery mechanism that would also provide a return on CMCP costs is more akin to the cost recovery mechanisms of Non-Wire Alternative (NWA) projects, which seek to avoid specific pieces of planned infrastructure and includes a return on NWA project costs to make the utility indifferent, on a dollar-per-dollar basis, to whether it spends money on a capital project or an NWA project. The CMCP is intended to serve the same purpose as demand response programs, to avoid the future need for distribution infrastructure which has not yet been identified or planned, therefore it is reasonable to recover costs of the CMCP and Demand Charge Rebate programs over a period of equal length as the recoveries of demand response programs, which is one year.

The Downstate Utilities are directed to include the following in their 60-day Immediate Solutions Filing: (1) proposals to implement the CMCP “core incentives,” with differential incentive payment rates to avoid distortionary market impacts if necessary; (2) proposals to implement the CMCP use case-specific adders for transit fleet charging, with other use case-specific adders if needed; (3) proposals to implement the 50 percent Demand Charge Rebate for the public DCFC use case; (4) proposals to implement cost recovery mechanisms as described above for the CMCP and Demand Charge Rebate programs; (5) any necessary tariff leaves or modifications in draft format to implement the CMCP and Demand Charge Rebate programs and to effectuate cost recovery of such.

The DPS Staff Whitepaper’s recommendations that EV charging customers continue to be included in the broader commercial service classes, and that the Commission direct the Utilities to begin collecting load and cost data from EV charging customers of sufficient quality for use in embedded cost of service studies through at least 2025, is adopted. These recommendations have garnered universal support from stakeholders, and are rational and reasonable steps to begin the process of determining whether or not EV charging customers should continue to be grouped within the broader commercial service class or separated into their own service class in the future. Similarly, stakeholders agreed unanimously that the Commission's deliberations regarding EV charging customer service classes should occur as part of a statewide generic proceeding. The Commission agrees that a statewide generic proceeding is the best venue for such considerations to allow for discussion with a full statewide context and to be cognizant of effective use of stakeholder time and attention to such a foundational topic.

<u>EV Phase-In Rate Solution</u>

The three primary options before the Commission for near-term Solutions are (1) the EV Phase-In Rate Solution recommended in the Whitepaper, which has garnered both broad and deep support from a wide array of stakeholders except the Utilities; (2) the Upstate Utilities' proposed EV Rate Program, which would provide varying levels of off-bill rebates against EV charging customers' demand charges in three graduations and require customers to separately meter EV charging loads; and (3) the Downstate Utilities' proposed combination of the pending standby service rates currently being considered by the Commission and continuation of the CMCP. Of these three options, the Commission finds the EV Phase-In Rate Solution, with certain modifications discussed below, to be the most reasonable solution.

The EV Phase-In Rate Solution balances: (1) the necessity to help accelerate EV charging station deployment, and thus further reduce friction for greater EV adoption across the light-, medium- and heavy-duty market segments; (2) providing actionable price signals for customers to minimize on-peak charging demands and maximize charging use during off-peak periods; (3) recognizing the potential for establishing a virtuous cycle where increased EV charging deployment decreases costs for other customers both within and beyond the EV charging customers’ service class, without discounting that cost shifts may occur if new revenues collected do not exceed incremental costs incurred; and (4) both the letter and intent of the requirements of PSL §66-s. Further, the Commission is persuaded by the numerous comments from non-utility stakeholders suggesting that a programmatic approach, which could potentially be modified more readily than a more durable tariffed rate design-based approach, would not result in operating cost relief which would be considered stable or financeable by commercial fleet, transit fleet, and public charging developers. Although the Commission appreciates and shares the Downstate Utilities’ concern for the potential cost-shifts in the Con Edison service territory under the EV Phase-In Rate Solution, the Commission nevertheless finds it to be the best Solution among those presented.

The Commission finds that the Upstate Utilities’ proposal to implement an EV Rate Program, beginning with a rebate equivalent to 75 percent of a participant’s traditional demand charge for customers with load factors of ten percent or less, would unreasonably blunt the demand charge’s usefulness as a tool to guide customers toward managing their demands without replacing such with other time-varying price signals.

The Commission appreciates the Downstate Utilities’ proposal to make use of a rate option that is much further along in the development process; however, there are two reasons why it is not advantageous to implement this option to the exclusion of the EV Phase-In Rate Solution. First, while using standby service rates and the CMCP may be beneficial for customers in comparison to the traditional demand charge rates, such solution may not provide sufficient support for most EV charging use cases at load factors less than ten percent and is particularly severe at load factors less than 5 percent, as demonstrated in Figure 3 of the Joint Utilities' comments.[22] Second, the DPS Staff Whitepaper identifies that the Contract Demand Charge poses challenges to customers similar in nature to traditional demand charges, and that customers that experience only a single high-demand charging session per day would potentially not experience savings under the Daily As-Used Demand Charge component.[23] The Downstate Utilities' comments do not convincingly dispel these concerns.

In their comments, the JU recommend five modifications to the EV Phase-In Rate Solution. First, the JU argue that a demand charge component should be present in the first graduation of the EV Phase-In Rate Solution applicable to customers with load factors of less than ten percent, arguing that an energy-only rate within the first graduation provides no incentive for customers to manage charging demand. The Commission disagrees for two reasons. First, while the time of use energy charge in the first graduation does not provide an explicit incentive for customers to minimize demand, it does provide an implicit incentive to do so since customers' incentives to reduce energy use during on-peak or super-peak periods will also likely result in lower demands during those same periods. Second, as demonstrated in Appendix E of the DPS Staff Whitepaper, even with a time of use energy rate, EV

[22] Joint Utilities comments, p. 28.

[23] DPS Staff Whitepaper, p. 10.

charging customers may not achieve positive net present values or financeable internal rates of return until achieving load factors equal to or greater than ten percent, suggesting that increasing the amount of demand charge into the first graduation would ultimately frustrate the purpose of the rate itself: to reduce barriers to the development of EV charging stations, especially while the utilization of such stations is likely to remain low.

Second, the JU recommend that the Commission modify the DPS Staff Whitepaper's recommended computation of a single annual load factor as the ratio of annual energy consumption to the product of the maximum demand experienced during the year and 8,760 hours, to instead compute the load factor used for determining an EV Phase-In Rate Solution participant's graduation as the average of the participant's 12 monthly load factors. Third, the JU recommend that participants' annual load factors be calculated once during a year instead of on a rolling quarterly basis. For both of these recommendations, the JU point to concerns that a customer with seasonal variation in charging demand and usage, for example, at a popular tourist destination featuring high usage during the summer months and low usage during winter months, may experience significant volatility in annual load factor, and thus eligibility for the EV Phase-In Rate Solution Graduations, when computed quarterly. The JU express concern that the combination of seasonal variation and quarterly computation of annual load factors may result in changes to a customer's graduation up to four times in a year. The Commission finds this concern compelling, but must also balance the need for new customers to be sorted into a graduation based on actual load factors as quickly as is feasible. With a single fixed date for annual determination of participant load factors, for example in January of each year, a customer that comes online one month after the annual load factors are calculated could be placed in the initial graduation for as long as 23 months before a full 12 months of actual load data is available during the fixed annual schedule.

Instead of the quarterly computations recommended in the DPS Staff Whitepaper, the Commission will require that the Utilities conduct semi-annual, or twice a year, computations of customer annual load factor. This less frequent computation schedule also helps smooth seasonal variations in charging load, and will ensure that customers cannot change graduations more than twice per year, as compared to the DPS Staff Whitepaper’s recommendation of up to four times per year. These semi-annual computations should be completed in the winter, considering a period of January through December of each year, encompassing a full summer period and two partial winter periods; and in the summer, considering a period of July of the previous year through June of the present year, encompassing a full winter period and two partial summer periods. This combination of smoothing out of seasonal variation and less frequent computation of annual load factor should ensure that movement between EV Phase-In Rate Solution graduations are the result of longer-term trends in charging station utilization and not seasonal variation.

Fourth, the JU assert that it is either technically infeasible or administratively burdensome to determine eligibility for the EV Phase-In Rate Solution based on whether a customer’s demand is at least 50 percent from EV charging load compared to other intermingled site load. As with the Demand Charge Rebate approved as an Immediate Solution, the Commission will require that the Utilities compute the would-be participant’s Charging Ratio, and that a customer with a Charging Ratio greater than 50 percent shall be considered eligible to participate in the EV Phase-In Rate Solution without the need to separately meter EV charging load and without complicated or burdensome computations to determine eligibility.[24]

Along similar lines, IPMA requests that the Commission clarify whether load factor used to determine a customer's EV Phase-In Rate Solution graduation would be based on either the load factor of the total site, or the load factor based on the sum of EV charger's charging capabilities in kW. For purposes of determining an EV Phase-In Rate Solution participant's annual load factor, Participants whose EV charging load is intermingled with other site load's annual load factor shall be measured based on the load factor of the total site to avoid technically infeasible or administratively burdensome computations to disaggregate EV charging load from other non-EV charging site loads.[25] Where an EV Phase-In Rate Solution customer separately meters their EV charging load, the annual load factor will be determined against the sum of installed charging capacity.[26] This arrangement will provide a benefit to customers that separately meter EV charging load while ensuring that customers with intermingled EV charging and other on-site load can participate in the EV Phase-In Rate Solution.

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24 A customer that separately meters EV charging uses shall be considered to have a charging ratio of 100 percent.

25 The annual load factor for a customer with intermingled EV charging and other site load would be computed as the ratio of total annual site energy use to the product of maximum site billing demand during the same annual period and 8,760 hours (or 8,784 hours during a leap year).

26 The annual load factor for a customer with separately metered EV charging load would be computed as the ratio of annual EV charging energy use to the product of the sum of installed EV charging capacity in kW and 8,760 hours (or 8,784 hours during a leap year).

The JU's fifth recommended modification to the EV Phase-In Rate Solution is that the Commission adopt a single super-peak period applicable within each utility's service territory, instead of implementing distinct geographically-based super-peak periods based on local grid needs. The JU further argue that avoidance of local super-peak periods, to the extent that they do not coincide with overall service territory super-peak, should be incentivized through CMCP incentives instead of creating a patchwork of local super-peak periods. The Commission finds the JU's arguments to be compelling. Given that electrical boundaries of circuits, radial load areas, and networks do not perfectly coincide with geographical or municipal boundaries, if super-peak period rates are passed along to consumers and differ within a utility's service territory consumers are likely to be confused about when and where to charge. Therefore, the Commission directs each Utility to propose a single super-peak period applicable throughout its service territory as part of their respective 180-day EV Phase-In Rate Filings.

The recommended design of the TOU Energy Charge included in the DPS Staff Whitepaper received broad support from numerous parties. Demand management technology parties, like NY-BEST, state that they support the DPS Staff Whitepaper's recommended proportions between off-peak charges, on-peak charges, and super-peak charges because it sends a strong price signal for customers to shift and manage their usage out of peak times and into off-peak periods. ATE notes in its comments, however, that it has reservations regarding the ratios between off-peak, on-peak, and super-peak charges that are extreme and may not be reflective of the utility's underlying costs. ATE suggests that the Utilities should have flexibility to propose different ratios between off-peak charges, on-peak charges, and super-peak charges on a case-by-case basis reflective of the costs of service in each utility. The Commission finds that while the DPS Staff Whitepaper's recommended ratios are reasonable, the Utilities will be allowed to propose different ratios as part of their 180-day EV Phase-In Rate Filing, provided they support the proposed ratios with sufficient justification.

In their comments, the Downstate Utilities take issue with the EV Phase-In Rate Solution as recommended in the DPS Staff Whitepaper, specifically, that the EV Phase-In Rate Solution results in lower charging costs between load factors of 10 percent and 20 percent in comparison to load factors above 20 percent where a customer would no longer be eligible to participate in the EV Phase-In Rate Solution. This issue is illustrated in Figure 3 of the JU's comments, which demonstrates that the effective dollar-per-kWh paid by customers increases rapidly in a step function from a lower cost just below 20 percent to the same price paid under traditional demand rates. The JU note that this price step would provide a significant perverse incentive for customers to maintain load factors below the 20 percent threshold recommended in the DPS Whitepaper to remain enrolled in the EV Phase-In Rate Solution instead of allowing load factors to increase. Along similar lines, the JEVIP state that they have not been able to fully scrutinize the 20 percent load factor cutoff recommendation in the DPS Staff Whitepaper, and recommend that the Commission consider a fourth graduation above the 20 percent load factor demarcation line. Further, ATE suggests that the Commission should allow the Utilities to propose different demarcation levels for the EV Phase-In Rate Solution graduations, and that the Utilities should be able to propose different ratios of energy and demand charges within those graduations. In combination, the

Commission finds that there is a need for further refinement of the graduations and ratios of energy and demand charges recommended in the DPS Staff Whitepaper.

The Commission finds there is a need to further smooth the transition from the end of the EV Phase-In Rate Solution, as recommended in the DPS Staff Whitepaper, in order to address both ATE’s concern that the 20 percent cutoff may be too aggressive in this early phase of EV charging station deployment, and the significant step up in charging costs after the 20 percent threshold, as identified by the JU. Therefore, the EV Phase-In Rate Solution shall include a fourth graduation for EV charging customers with load factors greater than 20 percent and less than 25 percent.[27] The Commission finds that a 25 percent TOU Energy Charge and 75 percent Traditional Demand Charge is a reasonable preliminary level, given that it splits the difference between the EV Phase-In Rate Solution’s third graduation and the full Traditional Demand Charge rate.

The Commission also finds it reasonable to allow the Utilities to propose different ratios of TOU Energy Charges and Demand Charges within the graduations, to an extent, to help address the perverse incentive provided by effective per-kWh charging costs which increase with increasing load factor under the EV Phase-In Rate Solution, as recommended in the DPS Staff Whitepaper. The Utilities should seek to develop EV Phase-In Rate Solution ratios in each graduation, and in combination across the graduations, that avoids the perverse incentive for charging stations to decrease load factor to stay enrolled in the EV Phase-In Rate Solution. While the Utilities may propose

[27] EV Charging customers with load factors greater than 25 percent shall not be eligible for the EV Phase-In Rate Solution. Such customers’ annual load factors shall still be calculated to ensure that they are allowed to participate again if their load factor falls below 25 percent.

different TOU Energy Charge and Traditional Demand Charge ratios in the second, third, and fourth graduations, the Commission will require that the first graduation shall be developed such that costs are recovered through a Customer Charge and TOU Energy Charge only, as discussed above. The Commission is cognizant that we are establishing significant constraints and requirements for the EV Phase-In Rate Solution, and that it may not be possible to fully eliminate all unintended incentives or cost step functions, however, care should be taken to avoid such if feasible.

The Commission finds the DPS Staff Whitepaper recommendation that the EV Phase-In Rate Solution be designed on a full embedded cost of service basis to be reasonable. Although CALSTART, NRDC and Sierra Club provide valuable insight that EV charging programs in other States provide rate discounts based on a utility’s marginal costs only for an initial period with a ramp up to full embedded costs gradually thereafter. The Commission is concerned that movement to marginal costs would further exacerbate the potential for cost shifts identified by the Downstate Utilities. Establishing the EV Phase-In Rate Solution using the full embedded cost levels for each service class has the best chance at simultaneously providing significant and meaningful operating cost relief for EV charging use cases, minimizing the potential for unwanted cost shifts among customers, and maximizing the potential for establishing the virtuous cycle where increased EV charging station development lowers long term rates.

In its comments, the City requests that the Commission clarify whether NYPA customers will be eligible to participate in the EV Phase-In Rate Solution. The Commission finds no compelling evidence or rationale that NYPA customers should be excluded from participation in such rate option. Therefore, NYPA customers shall be eligible to participate in the EV Phase-In Rate Solution.

In consideration of all of the above, the Commission directs the Utilities to develop and file EV Phase-In Rate Solutions 180-days after the effective date of this Order as follows. The EV Phase-In Rate Solution shall be available to all customers with a computed Charging Ratio greater than or equal to 50 percent. The EV Phase-In Rate Solution shall be designed on a revenue-neutral basis to recover the full embedded costs for each applicable service class. The EV Phase-In Rate Solution shall have four graduations. The first graduation shall be applicable to participants with annual load factors less than or equal to 10 percent. The second graduation shall be applicable to participants with annual load factors greater than 10 percent and less than or equal to 15 percent. The third graduation shall be applicable to participants with annual load factors greater than 15 percent and less than or equal to 20 percent. The fourth graduation shall be applicable to customers with load factors greater than 20 percent and less than 25 percent. Annual load factors for determining which graduation a customer is eligible for shall be computed semi-annually in January and in July.

The first graduation shall consist of a Customer Charge and a TOU Energy Charge. The second graduation shall consist of a Customer Charge a TOU Energy Charge, and should be designed to recover 75 percent of the remaining revenue requirement, and a traditional demand charge which should be designed to recover 25 percent of the remaining revenue requirement; however, Utilities may propose alternate ratios. The third graduation shall consist of a Customer Charge, a TOU Energy Charge which should be designed to recover 50 percent of the remaining revenue requirement, and a traditional demand charge which should be designed to recover 50 percent of the remaining revenue requirement; however, Utilities may propose alternate ratios. The fourth graduation shall consist of a Customer Charge, a TOU Energy Charge which should be designed to recover 25 percent of the remaining revenue requirement, and a traditional demand charge which should be designed to recover 75 percent of the remaining revenue requirement; however, Utilities may propose alternate ratios. The TOU Energy charge shall include an off-peak energy charge, an on-peak energy charge, and a four-hour seasonal super-peak energy charge.

In addition to the requirements above, the utilities shall include proposals to transition customers off of the Demand Charge Rebate or CMCP use-case-specific adders, as applicable, as part of their 180-day EV Phase In-Rate Filings.

Other Rate Design Solutions

The JEVIP, NY-BEST, and VGIC note that Supply capacity costs are charged on the basis of a customer's billing demand for customers that do not participate in Mandatory Hourly Pricing, or through a single-hour installed capacity tag for those that do, and request that the Commission direct the Utilities to offer additional Supply pricing options to EV charging customers. The JU argue that the Commission should focus on the delivery demand charge, which is the stated intent of PSL §66-s, and that modifications to such would be more impactful than further modifications to Supply charges.

The Commission notes, as well, that the Utilities each have already-existing tariff options allowing customers to opt in to supply hourly pricing, and that energy service companies (ESCOs) routinely offer alternate supply pricing for commercial customers to help customers manage their capacity charges or select different options for the energy portion of their Supply bill. The Commission is concerned that establishing a new monopoly-provided supply option specifically for EV charging customers would choke off a potential source of competition and innovation by squeezing ESCOs out of the EV market prematurely. Therefore, given that customers already have several options for alternate Supply pricing and the potential for utility involvement in this market to stifle new competition among ESCOs, the Commission declines to require the Utilities to develop new Supply options for EV charging customers at this time. The Commission is open to reexamining whether the Utilities should be required to implement additional Supply options for EV charging customers in the future if the competitive market fails to offer reasonable alternatives.

In its comments, NY-BEST recommends that the Commission engage in a broader reconsideration of traditional demand charges, specifically at the length of on-peak periods. The scope of the effort required under PSL §66-s is to provide EV charging customers solutions to work around the traditional demand charge, attempting to solve the "chicken and egg" problem of higher EV adoption required to build more EV charging stations and greater EV charging station deployment required to spur EV adoption. Engaging in a more in-depth review of the underlying design of the traditional demand charge at each utility, which previous Commissions have found reasonable, would require significant additional time and effort that is beyond the scope of the requirements of PSL §66-s. The Commission declines to undertake such a significant review at the present time as part of this proceeding. Similarly, NY-BEST requests that the Commission consider implementing alternate demand charges that customers could participate in. The Commission finds that there are a plethora of other demand charge options already, which include some of the features NY-BEST identifies as desirable, including the standby service rates which are presently available as an optional rate for all commercial customers, and the more advanced optional time-of-day demand rates. Therefore, the Commission declines to establish further alternatives to the traditional demand charge at this time.

The DPS Staff Whitepaper identified that energy storage systems greater than 1 MW of inverter capability installed at EV charging customer sites would not qualify for existing exemptions from standby rates, and therefore would frustrate the purpose of the EV Phase-In Rate Solution. The DPS Staff Whitepaper requested input from stakeholders as to whether energy storage systems installed at EV Phase-In Rate Solution participant sites should be exempted from standby rates. The JEVIP and VGIC state that the DPS Staff Whitepaper correctly identified the issue, and request that the Commission expand the exemption for energy storage beyond 1 MW for EV charging customers. Similarly, the JU recommend that the Commission extend the exemption from standby rates for energy storage projects installed at EV Phase-In Rate Solution participant sites provided that (1) the EV charging station meet all the eligibility requirements for the EV Phase-In Rate Solution, (2) that the energy storage inverter nameplate capacity is less than or equal to the EV charger nameplate capacity, and (3) that the energy storage system meet all other interconnection and other requirements for standby service. The Commission agrees that the exemption from standby service should be extended for those energy storage facilities installed at EV Phase-In Rate Solution participants' sites.

The Commission finds, however, that further simplification of the JU's proposed expansion to the standby rate exemption is necessary. Energy storage installations greater than 1 MW making use of the Demand Charge Rebate approved in this Order would also be frustrated by imposition of standby rates in the same way as EV Phase-In Rate Solution participants. Similarly, the Demand Charge Rebate will apply to some EV charging use cases but not others in the Downstate Utilities' service territories, potentially creating a confusing hodgepodge of eligibility requirements depending on utility service territory and EV charging use case.[28] Therefore, the Commission will not approve the proposed requirement that customers participate in the EV Phase-In Rate Solution, or any other specific Solution approved herein. The Utilities are directed to file, as part of their 60-day Immediate Solution Filing, draft tariff leaves to effectuate an exemption from standby rates for energy storage systems with inverter capability greater than 1 MW and less than or equal to the sum of nameplate EV charging capability, provided that such installations meet all other applicable interconnection and standby service requirements.

Data Reporting Requirements and Periodic Review Process

PSL §66-s requires that the Commission begin periodic review of Solutions no sooner than 18 months after the effective date of this Order. The Biennial Review Process recommended in the DPS Staff Whitepaper has garnered nearly unanimous support from stakeholders.[29] The DPS Staff Whitepaper outlines that the Biennial Review Process would begin with a notice for public

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[28] For example, if the standby rate exemption were premised on participation in the Demand Charge Rebate, energy storage systems greater than 1 MW in inverter capability installed at commercial fleet charging sites in one of the Upstate Utilities' service territories would be exempt from standby rates, whereas a similar installation within one of the Downstate Utilities' service territory would not be exempt.

[29] The Biennial Review Process would occur every two years. IPMA supports the biennial review process but recommends that such process begin after one year instead of two, which would not be allowable under the requirements set forth in PSL §66-s.

comment issued by the Secretary to the Commission regarding whether modifications should be made to the Solutions available at that time, and whether such Solutions should continue to be offered. The DPS Staff Whitepaper recommends that the Biennial Review Process should establish a rebuttable presumption that Solutions would remain necessary unless evidence is provided demonstrating that: (1) market conditions have improved; (2) EV charging business models have changed such that relief from traditional demand charges is no longer needed; or (3) other compelling evidence is provided. The Commission approves the process as recommended in the DPS Staff Whitepaper. To ensure that data is available that incorporates anticipated significant seasonal variations expected during the summer tourism months, the Biennial Review Process should begin during mid-winter. Specifically, DPS Staff is directed to issue a notice commencing the inaugural Biennial Review Process in January of 2025, continuing every two years thereafter unless canceled in a subsequent Commission Order.

Stakeholders were generally supportive of the type of data requested in the DPS Staff Whitepaper, but recommended a different data collection and reporting cadence. NRDC and Sierra Club suggest that, in addition to the data recommended in the DPS Staff Whitepaper, the Utilities should also report the percentage of charging occurring during off-peak, on-peak, and super-peak periods, on a quarterly and annual basis. The Commission finds this request for additional aggregated data to be reasonable, as it will help identify trends in customer usage and response to the price signals provided by the Solutions, and should be relatively simple to compute.[30]

[30] As discussed below, these data shall be reported on a semi-annual basis.

In its comments, ATE suggests that the quarterly data reporting requirements recommended in the DPS Staff Whitepaper are too onerous for customers to comply with. ATE states that complying with these requirements may require additional personnel employed by EV charging sites, and that some of the data requested may be difficult or infeasible for customers to provide. ATE suggests that instead of quarterly reports requiring data to be provided by customers to their respective utilities, a semi-annual, or twice a year, reporting schedule would be more reasonable. The JEVIP note that onerous data reporting requirements are part of the reason the PPI Program has been unpopular, and that some of their member organizations are not participating in otherwise-beneficial programs in New Jersey due to similarly onerous data reporting requirements. The Commission finds that the data reporting requirements need to balance ease of administration from both the participant and utility perspective, with the need for high-quality data to monitor operation and effectiveness of the Solutions.

Therefore, the Commission agrees with ATE’s suggestion that the quarterly data recommended in the DPS Staff Whitepaper is too onerous and that program data should be collected and reported on a semi-annual basis instead, using the same semi-annual periods established for calculating EV Phase-In Rate Solution participant’s annual load factors discussed above. The Utilities are directed to collect and report the following data semi-annually, on a per-participant basis if feasible: (1) the number of accounts participating in Solutions; (2) participants’ average peak demand kW; (3) participants average monthly kWh consumption; (4) participants’ average annual load factor on a year-to-date basis; and (5) the number and type of each charger participating. The Utilities are directed to collect and report the following data annually: (1) the year-over-year growth rate in number of accounts participating in Solutions; (2) an assessment of whether incremental EV charging load has resulted in local grid impacts; [31] (3) an assessment of the extent to which incremental EV charging load has resulted in upward or downward rate pressure on non-participating customer rates; and (4) an assessment on the impacts of Solutions on low- and moderate-income customers and Disadvantaged Community residents.

The DPS Staff Whitepaper recommends that the Commission establish specific dates for the first quarterly report and annual report as part of its consideration of the utility Immediate Solution Filings. The Commission finds this proposal reasonable, as the Commission is presently unsure of how long it may take the Utilities to gather the necessary data and file such reports. Therefore, the Utilities are directed to include proposals for when the first semi-annual and annual reports should be filed, and a proposal for an ongoing reporting schedule thereafter, as part of their 60-day Immediate Solution Filings.

CONCLUSION

The Commission anticipates that the bold actions directed in this Order will meaningfully reduce the barrier posed by traditional demand charges to public and fleet EV charging and help New York State meet its ambitious climate goals from the transportation sector. This Order establishes processes which themselves are compliant with PSL §66-s, or directs specific actions for future compliance with those portions of the law which require further action by the Commission. The combination of Immediate Solutions and the EV Phase-In Rate Solution approved in this Order are intended to

[31] The assessment shall include EV charging load from all service classes.

comply with the requirements of PSL §66-s(2) to implement technology-agnostic solutions that will not disincentivize innovation, provide monthly benefits to public charging customers, commercial fleets, transit fleets, and recognize differences between EV charging use cases and utility service territories. This Order is responsive to PSL §66-s(3), and directs utility Immediate Solution Filings responsive to PSL §66-s(5). The Utilities' Immediate Solution Filings will be considered by the Commission in a subsequent Order, and thereafter the approved Demand Charge Rebates and Commercial Managed Charging Programs will be implemented in compliance with PSL §66-s(6). Finally, the Biennial Review Process, semi-annual reporting requirements, and annual reporting requirements established in this Order are responsive to PSL §66-s(4).

The Commission orders:

1. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall make a filing including necessary draft tariff leaves to implement the Immediate Solutions, as discussed in the body of this Order, by no later than 60 days after the effective date of this Order.

2. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall make a filing including necessary draft tariff leaves proposing specific rates and other details related to the EV Phase-In Rate Solution, as

discussed in the body of this Order, by no later than 180 days after the effective date of this Order.

3. Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation shall file a proposed Commercial Managed Charging Program and necessary draft tariff leaves, as discussed in the body of this Order, within 180 days of the effective date of this Order.

4. Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, and Rochester Gas and Electric Corporation shall file an Implementation Plan, including necessary draft tariff leaves, detailing how the 50 percent Demand Charge Rebate will be operated, as discussed in the body of this Order, as part of filing directed in Ordering Clause No. 1.

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 and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall develop plans and necessary draft tariff leaves for deploying the funds recovered from the cancelled Direct Current Fast Charging Per Plug Incentive program, as discussed in the body of this Order, as part of the filing directed in Ordering Clause No. 1.

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 and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall file draft tariff leaves to effectuate an exemption from standby rates for energy

storage systems with inverter capability greater than 1 MW and less than or equal to the sum of nameplate Electric Vehicle charging capability, provided that such installations meet all other applicable interconnection and standby service requirements, as discussed in the body of this Order, as part of the filing directed in Ordering Clause No. 1.

7. Consolidated Edison Company, Inc. and Orange and Rockland Utilities shall include the following within the filing directed in Ordering Clause No. 1, as discussed in the body of this Order:

(1) proposals to implement the Commercial Managed Charging Program "core incentives," with differential incentive payment rates to avoid distortionary market impacts if necessary;

(2) proposals to implement the Commercial Managed Charging Program use case-specific adders for transit fleet charging and public level 2 charging, with other use case-specific adders if needed;

(3) proposals to implement the 50 percent Demand Charge Rebate for the public Direct Current Fast Charging use case;

(4) proposals to implement cost recovery mechanisms as described above for the Commercial Managed Charging Program and Demand Charge Rebate programs; and

(5) any necessary draft tariff leaves or modifications to implement the Commercial Managed Charging Program and Demand Charge Rebate programs or effectuate cost recovery of such.

8. Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc. shall file a proposal to implement a 50 percent Demand Charge Rebate for public Direct Current Fast Charging customers identical to the Demand Charge

Rebate, as discussed in the body of this Order for the Upstate Utilities, including necessary draft tariff leaves to implement the program and associated cost recovery, as part of the filing directed in Ordering Clause No. 1.

9. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall conduct semi-annual computations of customer annual load factor in January and July of each year, as discussed in the body of this Order.

10. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall implement the use of a Charging Ratio, as discussed in the body of this Order, and allow for a customer with a Charging Ratio greater than 50 percent to be eligible to participate in the Demand Charge Rebate and the Electric Vehicle Phase-In Rate Solution without the need to separately meter Electric Vehicle charging load.

11. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall propose a single super-peak period applicable throughout its service territory, as part of the filing directed in Ordering Clause No. 2, as discussed in the body of this Order.

12. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation

d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall collect and report the following data semi-annually, on a per-participant basis if feasible, as discussed in the body of this Order:

(1) the number of accounts participating in Solutions;

(2) participants' average peak demand kW;

(3) participants average monthly kWh consumption;

(4) participants' average annual load factor on a year-to-date basis; and

(5) the number and type of each charger participating.

13. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall collect and report that the following data semi-annually on an aggregated basis, as discussed in the body of this Order:

(1) the percentage of charging occurring during off-peak periods;

(2) the percentage of charging occurring during on-peak periods; and,

(3) the percentage of charging occurring during super-peak periods.

14. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall collect and report the following data annually, as discussed in the body of this Order:

(1) the year-over-year growth rate in number of accounts participating in Solutions;

(2) an assessment of whether incremental Electric Vehicle charging load has resulted in local grid impacts;

(3) an assessment of the extent to which incremental Electric Vehicle charging load has resulted in upward or downward rate pressure on non-participating customer rates; and

(4) an assessment on the impacts of Solutions on low- and moderate-income customers and Disadvantaged Community residents.

15. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall include proposals for when the first semi-annual and annual reports, as directed in Ordering Clauses Nos. 12, 13, and 14, should be filed, and a proposal for an ongoing reporting schedule thereafter, as part of the filings directed in Ordering Clause No. 1, as discussed in the body of this Order.

16. Department of Public Service Staff are directed to issue a notice commencing the inaugural Biennial Review Process in January of 2025, and continuing every two years thereafter, unless canceled in a subsequent Commission order, as discussed in the body of this Order.

17. The requirements of Public Service Law §66(12)(b) and 16 NYCRR §720-8.1 as to newspaper publication for the tariff revisions required in Ordering Clause No. 14 are waived.

18. 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 three days prior to the affected deadline.

19. This proceeding is continued.

By the Commission,

(SIGNED) MICHELLE L. PHILLIPS
Secretary

THE DOWNSTATE UTILITIES' PROPOSED TARGETED ADDERS

Load Factor	**Targeted Adder [$/Charger Nameplate kW]**	
	Expressed Monthly	**Expressed Daily**
1%	$ 7.50	$ 0.25
2%	$ 6.60	$ 0.22
3%	$ 5.70	$ 0.19
4%	$ 5.10	$ 0.17
5%	$ 4.50	$ 0.15
6%	$ 3.90	$ 0.13
7%	$ 3.30	$ 0.11
8%	$ 2.70	$ 0.09
9%	$ 2.10	$ 0.07
10%	$ 1.50	$ 0.05
11%	$ 0.90	$ 0.03
12%	$ 0.30	$ 0.01
≥13%	$ -	$ -

4. Budget Billing

Budget Billing is available to Customers served under Schedules R, RL, G or GS upon approval of the Customer's credit. Under the plan, a Customer pays for their total metered uses of electric and gas service for all purposes in even monthly payments (adjusted to the nearest dollar). Supplier charges for electric service and/or gas commodity are not included in Budget Billing. The monthly payment is calculated utilizing the Customer's recent 12 months of bills and the accumulated Budget Billing imbalance, including taxes applicable, divided by 12. In billing, the "Late Payment Charge" is Standard (Sec. 7.4) and is applied to each monthly payment.

Interest at the rate of one half of one percent per month is applied to any credit balance in the Customer's Budget Billing account. A credit balance occurs when the accumulated Budget Billing amount billed and paid under this plan exceeds the charges which would otherwise have been billed during the same period. Interest will be credited annually to all customers in the month of June.

A Customer may request to start billing, under this Rider, in any month including the month of their current bill. If 12 months of billing history is not available, the Company will estimate 12 months of bills in order to calculate a monthly Budget Billing amount. The Customer's Budget Billing account will be reviewed every 3 months, from the starting month, to determine if an adjustment is needed to the monthly Budget Billing payment. The Customer will be notified in that month's bill should the payment amount be changing in the subsequent month.

Upon discontinuance of the application of this Rider, any accumulated difference between the amounts billed at net rates under this Rider plus any accumulated interest and the charges at net rates including taxes, otherwise applicable for actual electric and gas uses becomes due and payable or refunded upon presentation.

Budget Billing is available to Market-Priced Service Customers, or to the Delivery Service portion of the bill for Customers who have selected an alternate Electricity Supplier.

5. Electric Vehicle Charging Distribution Demand Credit

Upon application by the Customer and approval by the Company, qualifying non-residential customers who have purchased and installed an eligible Electric Vehicle (EV) charging station within the Company's electric distribution service territory, may be eligible to receive a credit to partially offset their monthly distribution demand charge. This Rider is available to non-residential customers on Schedules GL or P.

Workplace, fleet, and multi-unit dwelling customers may be eligible to receive a credit for eligible EV charging stations purchased and installed on or after July 1, 2019. There is no cap on the number of chargers that can receive demand charge credits for workplace, fleet, and multi-unit dwelling customers. Other non-residential customers who have installed eligible DC Fast Chargers for public use on or after July 1, 2020 may also be eligible to receive the credit. The Company may issue demand charge credits for a maximum of 166 eligible public DC Fast Chargers that are not for workplace, fleet, and multi-unit dwelling customers.

Application submission for workplace, fleet, and multi-unit dwelling customers will begin on January 9, 2020 and terminate on June 30, 2021. No new applications will be accepted after April 1, 2021, and all project completion documentation must be submitted to the Company by June 30, 2021. Application submission for other non-residential customers will begin on December 1, 2020 and terminate on December 31, 2021. No new applications will be accepted after October 1, 2021, and all project completion documentation must be submitted to the Company by December 31, 2021.

(Continued on Next Page)

5. Electric Vehicle Charging Distribution Demand Credit – continued

The demand credit will be available beginning January 1, 2020 for workplace, fleet, and multi-unit dwelling customers and beginning December 1, 2020 for other non-residential customers, and will be a fixed amount, calculated by the Company and applied to the Customer's monthly bill for the account with the eligible installed and operational L2 and/or DC Fast EV charging station(s). For workplace, fleet, and multi-unit dwelling customers, the maximum allowable term for the demand charge credit is 30 months or through December 31, 2023, whichever comes first, from the date of application and documentation approval by the Company. For other non-residential customers who have installed eligible DC Fast Chargers for public use, the maximum allowable term for the demand charge credit is through December 31, 2023 or until such time as the Commission approves commercial EV rates, whichever comes first, from the date of application and documentation approval by the Company.

Demand Charge Credit Structure

Customer	EV Charging Station Type	Maximum Credit	Credit Length
Workplace, Fleet, or Multi-Unit Dwelling	Level 2 or DC Fast Charging Station	50% Aggregated Maximum Demand of the Charging Location	30 months or through December 31, 2023, whichever comes first
Other Non-Residential	DC Fast Charging Station for Public Use	50% Aggregated Maximum Demand of the Charging Location	Through December 31, 2023 or until such time the Commission approves commercial EV rates, whichever comes first

Demand charge credits are applied to the Customer's bill only for a portion of the maximum distribution demand charge resulting from the addition of EV chargers to the Customer's facility service and metered load. The demand charge credit amount will be calculated as 50% of the aggregated maximum demand of charging location for new or added L2 EV chargers and/or DC Fast EV chargers. The demand charge credit cannot exceed the Customer's monthly distribution demand charge.

The Customer must submit an application and documentation of the completed EV Charging station installation to the Company in order to become eligible for the demand credit (including receipts and/or invoices of the EV chargers, as well as proof of the installation from a certified electrician). The Company will determine acceptance, calculate the demand charge credit amount, and communicate these results to the Customer. Once approved, Customers may not add additional EV chargers to the demand charge credit.

CHARGING RATIO COMPUTATION EXAMPLES

Example No.	Sum of EV Charging Nameplate Capacity [kW]	Maximum Simultaneous Charging Demand [kW]	Charging Ratio Basis [kW]	Separately Metered EV load? [TRUE or FALSE]	Non-EV Charging Site Demand [kW]	Total Site Maximum Demand [kW]	Charging Ratio [%]	Eligible for Solutions? [TRUE of FALSE]
(1)	*(2)*	*(3)*	*(4)=MIN[(3),(4)]*	*(5)*	*(6)*	*(7)=(4)+(6)*	*(8)=IF[(5)=TRUE, 100%, [(4)/(7)]]*	*(9)=IF[(8)>=50%, TRUE, FALSE]*
1A	150	150	150	FALSE	50	200	75%	TRUE
1B	150	150	150	TRUE	50	200	100%	TRUE
1C	300	150	150	FALSE	50	200	75%	TRUE
2A	150	150	150	FALSE	200	350	43%	FALSE
2B	150	150	150	TRUE	200	350	100%	TRUE
3A	300	150	150	FALSE	200	350	43%	FALSE
3B	300	150	150	TRUE	200	350	100%	TRUE
4A	150	150	150	FALSE	150	300	50%	TRUE
4B	150	150	150	FALSE	155	305	49%	FALSE
4C	150	150	150	TRUE	155	305	100%	TRUE

- **Scenario 1 – Charging capacity is higher than other site loads**
  - **Scenario 1A** – EV charging capability is sized to meet the sum of EV charger nameplate capability, but the site intermingles EV charging load and other site load.
  - **Scenario 1B** – EV charging capability is sized to meet the sum of EV charger nameplate capability, but and the site separately meters EV charging load.
  - **Scenario 1C** – The site has multiple EV chargers, which are managed to provide a total simultaneous charging demand less than the sum of nameplate capacity of the EV chargers. The site intermingles EV charging load and other site load.
- **Scenario 2 – Charging capacity is lower than other site loads, and EV charging capability is sized to meet the sum of EV charger nameplate capability**

  - **Scenario 2A** – The site intermingles EV charging load and other site load.
  - **Scenario 2B** - The site separately meters EV charging load.
- **Scenario 3 - Charging capacity is lower than other site loads, and the site manages its EV load so that the total simultaneous charging demand is less than the sum of nameplate capacity of the EV chargers**
  - **Scenario 3A** - The site intermingles EV charging load and other site load.
  - **Scenario 3B** - The site separately meters EV charging load.
- **Scenario 4 – EV charging capacity is similar to other site loads**
  - **Scenario 4A** – EV charging load perfectly matches other site load, and the site intermingles EV charging and other site load. Scenario demonstrates that at exactly 50 percent Charging Ratio, customers are eligible to participate in the Demand Charge Rebate or EV Phase-In Rate.
  - **Scenario 4B** - EV charging load is slightly less than other site load, and the site intermingles EV charging and other site load. Scenario demonstrates that slightly lower than 50 percent Charging Ratio customers are ineligible to participate in Demand Charge Rebate or EV Phase-In Rate.
  - **Scenario 4C** - EV charging load is slightly less than other site load, but is separately metered. Scenario demonstrates that Charging Ratio is set to 100 percent and customer is eligible to participate in Demand Charge Rebate or EV Phase-In Rate.

SUMMARY OF COMMENTS

AEE and ACE-NY

AEE and ACE-NY state that managed charging plays a critical role in mitigating utility system costs associated with EV charging, and that charging station operators with the ability to not charge at times of peak demand can reduce or avoid utility costs associated with building their systems to meet higher peak demand. AEEI and ACE-NY state that fleet and other internal-use chargers are the most likely beneficiaries of a managed charging program since they can shift their business operations to maximize charging during off-peak times; however, public chargers have less of an ability to respond to managed charging programs because they cannot control when customers decide to charge. AEE and ACE-NY assert that the CMCP will be less effective at supporting public chargers, which will continue to face financial difficulty until the EV Phase-In Rate is available.

AEE and ACE-NY state that while the financial adders recommended in the DPS Staff Whitepaper may provide some support to existing chargers, they will not likely influence the financial viability of prospective charging stations since financing for prospective stations will depend more on the long-term impacts on rates and less on short-term programs such as adders. AEE and ACE-NY assert that the expediency with which the Commission adopts the Phase-In Rates will matter more than the adders. However, AEE & ACE appreciate the effort to provide near-term support through the adders. AEE & ACE recommend adders focus on providing support to chargers that are the least able to respond to Managed Charging Programs, such as public chargers. Adders provided at a flat rate based on a name plate capacity may support public chargers best in the near term.

AEE and ACE-NY state that they support the EV Phase-In Rate Solution recommended in the DPS Staff Whitepaper, which addresses their concerns that volumetric rates may be a long-term drag on station economics at higher load factors have been addressed by phasing in demand-based rates in a gradual manner as load factor increases.

ATE

ATE notes that improving load factors for DCFC charging stations is the key metric that should be addressed by Solutions, and identify four best-practices from other jurisdictions: (1) mitigating demand charges by either waiving such charges altogether or applying a discount to such for a defined period of time, including a midpoint review schedule; (2) development of cost-based rates without demand charges charges entirely; (3) development of cost-based rates with a portion of revenues collected through subscription charges or other charges that can reflect the cost of service without directly assessing demand charges; (4) providing targeted incentives that vary with site utilization or load factor. Of these four identified best practices, ATE recommends that the Commission approve streamlined proposals focused primarily on the first option - temporary reductions in demand charges.

In response to the DPS Staff Whitepaper’s request for input regarding the optimal format of use case-specific adders in the CMCP, ATE recommends that each utility should be allowed to implement program elements that are best suited for the specific costs and characteristics of each service territory. ATE suggests that a simple program design using a fixed incentive structure will be most efficient for utilities to develop and for customers to understand.

ATE states that it agrees with the DPS Staff Whitepaper’s recommendation that the CMCPs be designed to maximize the Societal Cost Test (SCT) ratio (SCT test) while supporting EV charging use cases. Because a CMCP that passes the SCT test provides benefits to all customers and service classes, ATE agrees with the DPS Staff Whitepaper's proposal to spread CMCP costs to all utility customers, not just those in the same service class as EV charging customers. ATE agrees with the DPS Staff Whitepaper's proposal to recover CMCP costs from customers through an existing surcharge mechanism, on a demand-basis for demand-billed customers and on an energy-basis for non-demand-billed customers, similar to Make-Ready Program costs.

ATE cautions against solution designs which require EV charging to be separately metered. ATE agrees with the DPS Staff Whitepaper's recommendations that customers should not have to separately meter EV charging load to participate in the CMCP. ATE notes that the design and requirements of the DCFC PPI Program, which, among other issues, required participants to separately meter their EV charging load, should serve as a warning against onerous eligibility requirements. ATE states that it agrees with the DPS Staff Whitepaper's proposal to repurpose the remaining PPI Program funding, and recommends that such funding be used to provide an immediate 50 percent Demand Charge Rebate for the duration of the CMCP. ATE further agrees with the DPS Staff Whitepaper's recommendation to offer existing PPI Program participants a one-time choice to either remain in that program or begin participation in the CMCP.

ATE states that it agrees with the DPS Staff Whitepaper's recommendation to begin collecting cost data related to EV charging customers to help inform future decision-making. ATE notes that the best venue for deliberations regarding whether to separate EV charging customers into their own service class is a statewide proceeding, as such proceeding would facilitate sharing of best practices among utilities, is more efficient and effective for non-utility parties to participate in, and could help facilitate more consensus and consistency on the specifications for the data that would need to be provided by charging station operators to utilities, and then on from utilities to the Commission for reporting purposes.

ATE notes that it agrees with the basic framework for the EV Phase-In Rate Solution, that is a rate which increases the amount of revenue collected through demand charges as station load factor increases. ATE states that while it finds the graduations and ratios presented in the DPS Staff Whitepaper to be reasonable, utilities should be allowed to propose different phase-in graduations and ratios if they present a reasonable rationale.

ATE notes that while it does not object to the recommendations for designing the on-peak and super-peak charges for the time of use energy rate component of the EV Phase-In Rate Solution, it does not endorse the DPS Staff Whitepaper's recommended multiples of two-times and three- to five-times for the on-peak and super-peak components compared to the off-peak energy charge. ATE states that its concern centers on whether such extreme differences between off-peak, on-peak, and super-peak charges are reflective of utilities' actual costs, and state that it would prefer to if design of such rates were completed on a case-by-case approach based on specific proposals by individual utilities reflective of costs in each service territory.

Regarding the DPS Staff Whitepaper's recommendation that the CMCP transition from a program to support EV charging use cases to one based solely on the values managing charging behavior can achieve for the grid, ATE cautions against implementing any program elements which are not easy for customers to understand. ATE notes that it is particularly important to consider customer perspectives in this early phase of EV charging station buildout, since managing electricity costs are not necessarily EV fleet owners' or EV charging station developers primary business or reason for adopting EVs. ATE cautions that developing EV charging capability continues to be a risky business, and that charging station developers are most likely to deploy their limited capital in states with favorable planning processes with utilities, state incentives, and rate designs – implying that EV charging developers will invest elsewhere if conditions are not seen as favorable in New York.

ATE expresses concern regarding the DPS Staff Whitepaper's recommendation that certain customer data be collected and reported quarterly, including: (1) number of accounts participating in Solutions; (2) participants' average peak demand kW; (3) participants' average monthly kWh consumption; participants' average annual load factors on a year-to-date basis; and (5) the number and type of each charger participating. ATE asserts that these data reporting requirements will require substantial resources for participants to provide, and are too frequent. ATE notes that some of the data requested may be technologically infeasible for participants to provide, and some smaller charging station operators may not have the resources available to be able to comply with the requirements. ATE suggests that twice-yearly data reviews are more reasonable than the quarterly reporting recommended in the DPS Staff Whitepaper, but agrees with the DPS Staff Whitepaper's recommended cadence of the biennial review process.

BP Pulse Fleet

Bp Pulse Fleet supports the proposal to create utility CMCP for customers with light-duty, heavy-duty, and fleet electric charging. BP Pulse Fleet states that this near-term incentive is appropriate for encouraging smart charging behavior and that all utility customers benefit from avoided costs when large energy users avoid adding to incremental utility peak demand. BP Pulse Fleet cautions, though, that open-ended demand charge relief runs the risk of creating a dependency on distorted price signals and encourages modest and time limited policy outcomes.

BP Pulse Fleet is very supportive of the programs incentives to reduce the cost of including automated load management (ALM) in EV charging projects – using funds from underutilized Per Plug Incentive Programs. BP Pulse Fleet states that EV charging equipped with ALM is fundamental to large scale EV charging projects as it facilitates flexible electricity demand. BP Pulse Fleet recommends that the Commission clarify that these incentives will apply to costs that support on-site energy storage, battery integrated EVSE, and ALM software solutions. BP Pulse Fleet states that in addition to upfront incentives, incentives to reduce recurring costs such as licensing, leasing, and maintenance would be useful as well.

BP Pulse Fleet is supportive of incentives for ALM as the technology provides cost savings that improve the business case for EV. BP Pulse Fleet states that ALM provides energy cost management by optimizing charging times to meet vehicle energy needs and provides utility customer benefits by enabling EV charging as flexible load, reliable demand response, and energy storage that can incorporate renewables year-round.

CALSTART

In its preliminary statement, CALSTART notes that it has observed in multiple settings how traditional demand-based rates can erode the business case for fast charging station operators and slow fleet transitions to EVs. CALSTART notes that its financing partners identify utility costs as a key driver of uncertainty in considering risk and financing of fleet investments. CALSTART states that it generally agrees with the DPS Staff Whitepaper's recommendation to immediately implement a CMCP while beginning a process to develop rate design-based alternatives to traditional demand charges. CALSTART states that the primary focus of this effort should remain on the development of rate design-based alternatives making use of TOU energy charges.

CALSTART identifies five principles for rate design supportive of transportation electrification in general, and fleet electrification in particular: (1) rates should be cost-driven and reflect the marginal costs of providing service; (2) rates should be balanced between demand-based charges and other types of charges, and should not be based on a demand component alone; (3) rates should result in utility bills that are reasonably predictable based on projected usage; (4) rates should be flexible enough to offer users robust TOU price signals to provide options for customers to manage their usage away from peak periods; and (5) rates should be forgiving if a customer exceeds usage expectations and not include significant demand ratchets. CALSTART points to the Business EV Rates at Pacific Gas & Electric Corporation as an example of a rate design which comports with their recommended criteria, which includes a balance of TOU energy rates, monthly subscription demand charges, and results in somewhat higher per-kWh charges and lower per-kW charges.

CALSTART cautions, however, that DCFC charging use cases and fleet electrification may require different strategies and solutions. CALSTART notes that rate design strategies that respond to the prevailing phenomenon of low-but-improving load factors are well suited for assisting DCFC sites, but are unlikely to address the needs of fleet charging customers. Similarly, CALSTART notes that fleet charging is more readily controllable by fleet managers than public DCFC charging. CALSTART urges the Commission to consider a holistic set of solutions to separately assist public DCFC charging and fleet charging, instead of a single solution applicable to both.

CALSTART states that it agrees with the DPS Staff Whitepaper's proposal to implement a biennial review process, and encourages the Commission to consider issues on a statewide basis.

City of New York

The City of New York (the City) is generally supportive of the proposed CMCP, particularly its focus on the charger station site rather than the vehicle. Additionally, the City is supportive of the proposed graduations and time-of-use rates under the Phase-In Rate. The City requests clarification from the Commission that customers will be able to switch between graduations as long as the Phase-In Rate remains available; however, the City states that it is concerned with potential volatility of customers being switched between graduations up to four times per year. To address potential volatility of customers transitioning between EV Phase-In Rate Solution graduations, the City recommends that a customer should only move between graduations if its load factor corresponds to the new graduation for two consecutive quarters. The City requests that the Commission clarify that customers taking service under NYPA's tariff be eligible to participate in the CMCP and EV Phase-In Rate.

The City agrees with DPS Staff that EV charging load should remain as part of the existing commercial service class until more data is available that could be used to inform whether a separate EV charging load service class is warranted. The City states that it generally it agrees with DPS Staff's proposal to include incentive adders that support public charging and remote areas, but requests that the "remote" adders for Con Edison be based on charger density at time of installation rather than population density. The City states that failure to modify the remote adder to be based on charger density would exclude the entirety of Con Edison's service territory, which includes New York City and Westchester County.

The City also states their support of DPS Staff's proposal to allocate unspent funds in the DCFC Per-Plug Incentive Program to support demand management through the CMCP.

EDF

EDF agrees with the centering of commercial managed charging in DPS Staff's proposal. EDF states that commercial managed charging programs should encourage the deployment of DER for maximum effectiveness and ideally incorporate locational price signals. EDF comments that the DPS Staff Whitepaper fails to justify its recommendations in the context of MHD fleets. EDF notes that the financial analysis conducted by NYSERDA that has been shared with stakeholders in this proceeding focuses only on the economics of publicly accessible DCFCs. EDF states that both NYSERDA and Guidehouse's analysis also excludes any consideration of non-distribution system costs borne by charging customers as part of their electric bills, including capacity, transmission, and commodity costs, taxes, and other fees. EDF comments that without any analysis of the effect of the DPS

Staff Whitepaper's proposals on customers' total charging costs, stakeholders cannot reasonably be expected to provide adequate feedback on whether the proposals are appropriate for reducing these costs.

EDF states that the multi-step proposal risks creating a confusing pricing environment for commercial charging customers, particularly fleets that do not have significant experience being large electricity customers, which may be detrimental to meeting the State's EV deployment mandates. EDF comments that the limits of the DPS Staff Whitepaper's recommendations underscore the need for the Commission to take a holistic look at the needs of medium- and heavy-duty fleets in a separate proceeding.[32]

FreeWire

FreeWire supports the proposed set of immediate and near-term Solutions. FreeWire's viewpoint is aligned with DPS Staff in that increased deployment of EV charging infrastructure is imperative to support the adoption of EVs and that the build-out is done in a manner that is both cost effective and minimized grid impact. FreeWire finds the proposal well-conceived and balances the complex dynamics of rate design.

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[32] In her January 10, 2023, "Achieving the New York Dream" State of the State address, Governor Hochul announced that she will be directing DPS Staff to launch a proceeding that will identify and remove the barriers to the efficient and timely deployment of the charging infrastructure needed to electrify New York's medium and heavy duty vehicles. See: https://www.governor.ny.gov/sites/default/files/2023-01/2023SOTSBook.pdf, page 136. To the extent that the Commission's actions in the Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structures for Commercial Electric Vehicle Charging do not fully address the needs of the medium- and heavy-duty fleet customers, such further needs are expected to be addressed in that forthcoming proceeding.

FreeWire approves of DPS Staff’s solution to repurpose the unused funds authorized for the DCFC Per-Plug Incentive Program as this support is needed to incentivize customers to adopt these technologies once the hurdle of traditional demand charges is reduced. FreeWire states that this approach will bring innovative technology solutions into parity with conventional DCFC solutions.

FreeWire is in strong support of the proposed incentive design to encourage peak avoidance relative to EVSE nameplate capacity and off-peak charging and finds this will send appropriate price signals to the market resulting in beneficial charging behavior. FreeWire finds DPS Staff’s rationale to begin CMCPs immediately is sound even if the degree of benefits varies between utilities at this time.

FreeWire disagrees with the Upstate Utilities and Electrify America, who recommended against immediate adoption of CMPCs during the November 4, 2022 stakeholder workshop. FreeWire supports DPS Staff’s recommendations to begin implementation of CMPCs now while working towards a well-designed and sustainable rate design option. FreeWire states the immediate program should be designed in such a way that when a potential DCFC site host is selecting hardware and software, they should be relatively indifferent, on an operational cost basis, between conventional DCFC that makes use of demand charge relief and DCFC that employs load management solutions.

FreeWire agrees with DPS Staff that incentive adders through an upfront payment is an effective approach. FreeWire states that, is their experience, an upfront incentive is more effective as it is relatively simple and understandable to potential site hosts. FreeWire maintains that upfront incentive adders are an additional enticement for participation in CMCPs and can work together with baseline incentives.

FreeWire is generally supportive of the proposal to transition to new CMCP design once the EV Phase-In Rate is available. FreeWire states that it is appropriate to transition this program from supporting business models to incentivizing specific beneficial charging behaviors and believe rewarding charging behavior for the value being accrued is sensible and can work well with the per-kW peak avoidance or per-kWh off-peak incentives. However, FreeWire suggests that incentive adders should continue to be offered to establish operational cost equivalency between conventional DCFC and those that employ load management, and in the event that this is the case, available PPI funding could continue to serve this purpose.

IPMA

IPMA states that it supports the need to have program designs that provide incentives for off peak charging and disincentives for peak charging. IPMA note that charger infrastructure companies routinely offer software flexibility to allow customers to limit the demand imposed on the utility system and to curtail charging during peak periods needed to balance the need of retail charging customers with the potential cost customers incur from utility demand charges. IPMA stats that the potential requirement to reduce charging demand is of particular concern for low load customers, but recognizes the unavoidable compromise between allowing unfettered access to retail charging customers and the cost that will be imposed on the system to meet those demands.

IPMA suggests that the number of hours per year that charging demand needs to be managed should be minimized because customers would be forced to limit access to chargers or slow charging speeds, impacting access to retail charging customers. IMPA asserts that incentives would ideally only be imposed to discourage peak usage when absolutely necessary, which may require a combination of tariff-based incentives and optional real time, with the latter benefitting retail charging customers because it will minimize the number of impacted hours. However, IPMA recognizes that only the local utility can decide when and where real time signals are economically beneficial, which is an issue of particular concern in "Disadvantaged Community Zones".

IPMA states that it does not take a position on whether EV charging customers should be segregated into separate service classes. IPMA does assert, however, that recovery of EV charging subsidies should not be borne solely by the commercial customers, and should instead be allocated to all customers, for at least the first five years. IPMA argues that all utility customers will benefit from the environmental benefits and cost savings associated with EV, therefore all customers should help pay for such costs.

IPMA supports DPS Staff's suggestion of three rate graduations to the EV Phase-In Rate solution, with the caveat that values may need to be adjusted to reflect evolving costs in utility rates and EV infrastructure. IPMA supports DPS Staff's recommendation for a periodic review; however, IPMA supports having the review sooner, in one year instead of two. This need not be a full review, just DPS Staff updating the model and making recommendations for public comment.

IPMA states that it is also concerned with the predictability and equity of retail charging customer demand. IPMA states that consumers in its members' local areas are most likely to charge predominantly at home, using public charging options only when absolutely necessary. IPMA observes that charging at home costs consumers roughly one-third as much as charging at a station, and states that this disparity exacerbates equity issues between homeowners and residents without access to at-home charging, and needs to be addressed.

IPMA also requests that the load factor be calculated based on installed charger capacity and not customer experienced load factor.

Joint EV Industry Parties

The Joint EV Industry Parties (JEVIP) generally support the EV Phase-In Rate proposed in the DPS Staff Whitepaper, discuss shortcomings of the DPS Staff Whitepaper's proposal to implement Commercial Managed Charging Programs, recommend an alternative demand charge alternative structure, and provide feedback on the specific questions posed in the DPS Staff Whitepaper.[33] The JEVIP state that the EV Phase-In Rate framework is highly constructive, incorporates several rate design elements that have been successfully deployed in other jurisdictions, and request that the Commission approve it. In response to the request for feedback on the structure of the EV Phase-In Rate graduations in the DPS Staff Whitepaper, the JEVIP note that the DPS Staff Whitepaper relies on the assumption that there is little need for relief from demand charges above 20% load factor. The JEVIP state that they have not been able to fully scrutinize some of the assumptions relied on in NYSERDA's business case analysis, which demonstrate favorable economic conditions at and above a load factor of 20%, and note their concerns regarding the results of such analysis. The JEVIP recommend that the Commission consider a fourth EV Phase-In Rate graduation for customers with load factors greater than 20% in utility service territories with higher-than-average demand charge rates.

[33] The Joint EV Industry Parties comments focus predominantly on public DCFC charging, and do not take a position on the DPS Staff Whitepaper's proposals regarding other use cases such as workplace and fleet charging.

The JEVIP do not agree with the DPS Staff Whitepaper's recommendation that the utilities develop and implement a CMCP for public on-the-go DCFC charging stations. While the JEVIP argue that CMCPs should not be considered a Solution under PSL §66-s, they do agree with development of CMCPs to operate alongside other operating cost relief mechanisms. The JEVIP make four arguments against implementation of CMCPs as an immediate Solution.

First, the JEVIP assert that the CMCP will not sufficiently address the barriers posed by demand charges for public DCFC stations. The JEVIP contend that the CMCP would potentially create a perverse incentive for developers to install higher capacity charging stations than what is necessary to serve the local area in response to the incentives provided under such a program. The JEVIP assert that the anticipated structure of the CMCP, which would provide incentives based on the difference between maximum charging capability and maximum charging demand experienced, would provide greater incentives to oversized charging stations while providing few incentives to lower capability stations likely to operate at or near maximum capability when vehicles charge. The JEVIP note that the charging demands that a station experiences are related to specific capabilities of the vehicles which charge at the site, with newer vehicles being able to charge at a higher demand rate. As an example, the JEVIP note that the Chevrolet Bolt is capable of charging at approximately 55 kW, whereas the Hyundai Ioniq 5 is capable of charging at approximately 220 kW. Thus, the JEVIP assert that 150 kW plugs will be charging at a greater percentage of their maximum capability during a given charging session than a 350 kW plug, and would therefore be eligible for much lower incentives under the CMCP than higher capability plugs.

The JEVIP contend that the incentives provided through a CMCP would be volatile and unpredictable from month to month, thus reducing charging station developers' ability to rely on such incentives to mitigate demand charge costs. The JEVIP note that while charging station operators cannot control what type of vehicles show up to using their charging service, the difference in maximum demands from simultaneous charging of two high-demand vehicles greatly exceeds the simultaneous charging demands of two lower-demand vehicles, thus the incentives available during a month where two high-demand vehicles charged simultaneously would be significantly lower compared to a month where two lower-demand vehicles charged simultaneously.

The JEVIP also argue that the incentives available under a CMCP of 5 to 10 percent savings toward applicable demand charges as outlined in the DPS Staff Whitepaper are not sufficient to provide significant relief for charging station operators. The JEVIP notes that at load factors less than 10 percent, the cost of electricity to charge a vehicle is well above the equivalent cost of gasoline, thus a greater reduction in electricity costs is needed to achieve parity between EV charging costs and gasoline prices. The JEVIP also note that the cost of electricity is just one of many costs - such as recovery of capital costs, operations and maintenance costs, and other ongoing expenses – which charging station operators must recover to earn a profit and continue operating, and failure to do so may result in a shift of investment to other jurisdictions with more favorable operating conditions.

Second, the JEVIP argue that charging station operators' response to CMCP incentives will degrade EV charging consumers' experience and satisfaction. The JEVIP assert that any CMCP incentives a charging station operator may earn would be outside their control unless the operator decides to reduce, or throttle, charging capability during peak periods, which may in turn result in longer charging sessions, consumers queueing while waiting for a charging port to become available, or drivers potentially becoming stranded if queues are too long.

The JEVIP also contend that a CMCP would be difficult for both charging station operators and consumers. The JEVIP assert that charging station operators may have difficulty managing different peak period designations within a given utility’s service territory; for example, in Con Edison’s service territory, where there are four different identified peak periods depending on location, and between different utility service territories. Further, the JEVIP contend that the DPS Staff Whitepaper’s proposal to address the need for additional incentives for public DCFC charging, adding a use case specific adder, would add another layer of complexity and uncertainty for charging station developers, and not provide the regulatory certainty needed to accelerate investment in charging stations. The JEVIP further note that it may be difficult for consumers to understand different peak periods, know what the applicable peak period is for the charging station they want to use, and may not be willing or able to respond to peak period price signals.

Third, the JEVIP contends that customers actions to participate in the CMCP may run afoul of requirements for federal incentives under the NEVI program. The JEVIP note that the NEVI program guidance documents require that DCFC stations have at least 600 kW of combined charging capability, and require a minimum delivered power level of 150 kW per charger. The JEVIP asserts that a customer that throttles its charging capability during peak times to respond to the CMCP would potentially violate NEVI program rules, thus making simultaneous participation in NEVI programs and the CMCP unavailable, and potentially reduces New York's ability to leverage federal incentive that would otherwise be available.

Fourth, the JEVIP argue that the CMCP would violate the requirements of PSL §66-s by implementing a program which does not provide adequate demand charge relief for the public DCFC use case, and would amount to a technology-specific mandate for equipment to help charging station operators participate in the program without negatively impacting EV drivers' experience. The JEVIP contend that public DCFC is incompatible with the CMCP, since public DCFC operators are unable to manage their own charging loads and therefore cannot effectively shift charging away from on-peak periods as intended for the program. The JEVIP also assert that charging station operators would be required to install energy storage or advanced load management software to respond to CMCP incentives, amounting to a technology-specific solution disallowed under PSL §66-s. The JEVIP further note that it may be infeasible to add energy storage systems to charging stations due to lack of space in crowded parking lots, unavailability, or prohibitive costs of additional real estate at a size needed to accommodate an appropriately-sized energy storage system, as well as increased capital costs of adding energy storage in the first place.

The JEVIP assert that implementing an unfavorable interim program while awaiting enactment of the EV Phase-In Rate will jeopardize achievement of New York's ambitious EV adoption goals, and express concern that a CMCP would not likely be able to go into effect until the third quarter of 2023. The JEVIP note that the absence of programs to help lessen the barriers posed by demand charges immediately represents lost opportunities to leverage the complementary Make-Ready Program and federal NEVI program funding. The JEVIP underscore the need for an effective relief from demand charges for public DCFC stations, noting that addressing such barrier is important for improving equitable access to EV charging for New Yorkers living in multi-unit dwellings (MUDs), which are especially prevalent in urban areas. The JEVIP point to a recent University of California Los Angeles study which shows that approximately 43 percent of MUD residents, approximately three times the level of non-MUD residents, rely on public DCFC as their primary means of charging. In the event that the Commission determines to implement a CMCP as its preferred Solution, the JEVIP requests that the Commission direct the utilities to consult with the JEVIP member organizations in designing incentives for the public DCFC use case.

As an alternative to the CMCP, the JEVIP recommend that the Commission implement an off-bill rebate equal to 50 percent of the total distribution demand charge (Demand Charge Rebate) for public DCFC customers. The JEVIP suggest that a similar rebate may be appropriate for public level 2 charging stations with a high number of chargers, as well as public transit fleet and other fleet charging applications that may need to charge during peak hours. The JEVIP suggest that the Demand Charge Rebate be provided to eligible customers as an off-bill credit, paid for using the balance of unspent DCFC PPI Program funds, and continue until the EV Phase-In Rate becomes available. The JEVIP note that similar 50 percent Demand Charge Rebate programs are currently in place in Maryland, where the rebate is effectuated through utility tariffs and was able to be enacted in approximately two months following approval, and New Jersey, which implemented off-bill rebates. However, the JEVIP note that several of their member organizations have chosen not to participate in the New Jersey programs due to onerous data reporting requirements.

The JEVIP assert numerous advantageous qualities to their proposed Demand Charge Rebate, including: (1) predictability and visibility into charging station operating costs; (2) clarity and simplicity; (3) the ability to be administered as an off-bill credit; (4) use of an existing funding mechanism; (5) provides rate certainty to both existing charging station operators and new entrants; and (6) retains a focus on creating and maintaining a positive EV driver experience. The JEVIP state that the Demand Charge Rebate can be implemented within the same statutory timeline as laid out in the DPS Staff Whitepaper, and would be no more difficult to implement than a CMCP. The JEVIP contend that the number of incentives per charging sector should be limited to avoid a confusing patchwork of layered incentives, which the Demand Charge Rebate would accomplish while the CMCP would exacerbate. The JEVIP assert that the approximately $31 million remaining in PPI Program authorization should be able to sustain the Demand Charge Rebate payments until the EV Phase-In Rate is available, and recommends that costs should be collected in a manner identical to the DPS Staff Whitepaper's recommend CMCP cost recovery mechanism.[34]

The JEVIP also provide specific input regarding questions posed or stakeholder comment in the DPS Staff Whitepaper. First, The JEVIP state that energy storage systems installed at public DCFC stations are likely to exceed the one-megawatt (MW) threshold to trigger mandatory standby service rates, resulting in a conflict between the EV Phase-In Rate and criteria for assigning customers to standby service rates. The

[34] The JEVIP make contradictory statements regarding cost recovery. Since PPI Program funds have already been collected from customers, further cost recovery from customers would not be required unless the Demand Charge Reduction costs exceed the amount collected for PPI.

JEVIP recommend that the Commission implement an exemption to standby service rates for EV charging stations which install energy storage.

In response to the question in the DPS Staff Whitepaper regarding determinations of whether EV Charging customers should be placed into separate service classes or continue to be part of existing commercial service classes, the JEVIP request that such discussions occur in statewide generic proceedings to ensure consistency among distribution utilities and to maximize stakeholder input on such matters.

Finally, the JEVIP note that electricity supply charges can include demand components, which present a considerable barrier for public DCFC stations. The JEVIP note that the demand components of the Supply charge may be based on non-coincident peak (NCP) demand, or Coincident Peak (CP) demand.[35] While the JEVIP identify both the NCP and CP Supply demand charges as barriers, with NCP demand charges having the same effect on charging station economics as Delivery demand charges, the JEVIP identify CP Supply demand charges as especially volatile and problematic. The JEVIP recommend that the Commission modify the demand-based Supply charges to instead offer a stable volumetric Supply charge option for public DCFC stations. The JEVIP further recommends that the Commission consider review of Supply charge options a part of the biennial review process.

Joint Utilities

[35] Generally, installed capacity (ICAP) prices are assigned to customers that are enrolled in mandatory or voluntary hourly pricing based on that customer's peak demand during the CP hour, or ICAP tag. Customers that are not enrolled in hourly pricing are assigned ICAP costs based on their billing, or NCP, demand.

The Joint Utilities (JU) propose two different sets of Solutions, one for the Upstate area covering the service territories of Central Hudson, National Grid, NYSEG, and RG&E (Upstate Utilities); and one for the Downstate area covering the service territories of Con Edison and O&R (Downstate Utilities). The JU state that implementing different Solutions for the Upstate Utilities and Downstate Utilities is reasonable because commercial EV charging is expected to increase at different rates between the two areas of New York, that there is significantly higher value for managing charging demands in the downstate area where grid costs are higher, and that PSL §66-s allows for service territory-specific Solutions.

Immediate Solutions

The Upstate and Downstate Utilities approaches to the immediate Solutions recommended in the DPS Staff Whitepaper differ. The Downstate Utilities state that they support the DPS Staff Whitepaper’s proposal to implement a CMCP with targeted adders, which they assert can provide predictably consistent and financially meaningful operating cost relief to EV charging sites while simultaneously encouraging and entrenching charging behavior which benefits the grid from the beginning. The Downstate Utilities state that a CMCP in their service territories has several advantageous qualities in that all EV charging stations would be eligible to participate regardless of load factor or the presence of inter-mingled non-EV charging site load, and could be made available expeditiously. The Downstate Utilities state that a performance incentive in the form of an EAM is appropriate for driving beneficial behavior through the CMCP, but do not propose any specific metrics.

The Downstate Utilities also identify several other benefits of implementing a CMCP. First, the CMCP with adders would comply with the PSL §66-s requirement to provide operating cost relief to all EV charging stations. Second, the CMCP incentives would be right-sized to neither over-incentivize nor under-incentivize charging station use cases, could be established to slightly over-incentivize EV charging during the early phase of the EV charging market development if the Commission desires, and could be adjusted through the biennial review process. Third, the CMCP would incentivize, but not require, the use of innovative business models and demand management technologies, and would retain incentives for charging stations to improve their load factors. Fourth, the CMCP would limit adverse financial consequences and shifting of costs by right-sizing incentive payments, limiting the total cost of the operating cost relief solution, and CMCP costs would be tracked reported in a transparent manner. The Downstate Utilities state that while the CMCP and adder incentives were not specifically designed to achieve parity with the cost of gasoline, the total bill cost including delivery charges, supply costs, and taxes results in approximately $0.38 per kWh, which less than the equivalent cost of electricity of about $0.50 per kWh. The Downstate Utilities propose that the adder incentives only be made available until such time as the Commission approves the pending standby service rates presently being considered by the Commission in the Value of Distributed Energy Resources Proceeding, Case 15-E-0751.[36]

The Downstate Utilities propose to pay CMCP incentives monthly based on three incentive types: (1) a pro-rated peak avoidance kW incentive for avoiding charging demands during

[36] Case 15-E-0751, Value of Distributed Energy Resources, Order Establishing an Allocated Cost of Service Methodology for Standby and Buyback Service Rates and Energy Storage Contract Demand Charge Exemptions (issued March 16, 2022); the Commission is presently considering filings made by the Joint Utilities in compliance with this Order on July 14, 2022.

local peak periods; (2) an off-peak charging incentive for increasing charging during overnight periods; and (3) a targeted adder incentive for public charging and transit authorities to provide additional support for these use cases which may have to charge during on-peak periods. For the pro-rate peak avoidance kW incentive, the Downstate Utilities propose to measure the avoided peak kW by subtracting the highest charging station site load in a given month during local peak periods, such as those used in Con Edison's Commercial System Relief Program (CSRP), from the nameplate charging capacity of charging site.[37] The Downstate Utilities would then multiply the calculated amount of avoided peak demand by an incentive payment rate, one payment rate for summer months of June through September, and a different payment rate for the months of October through May.[38] For the off-peak charging incentive, the Downstate Utilities propose to provide an incentive payment for every kWh of energy used for EV charging during the overnight period from midnight to 8 a.m.[39] The Downstate Utilities note that the incentives they designed for Con Edison were set at less than the grid value associated with the beneficial behaviors incentivized under the program, meaning that higher incentive levels could be offered if desired.

[37] The CSRP peak windows for Con Edison vary based on geographic location throughout its service territory, and range from 11 a.m. to 3 p.m., 2 p.m. to 6 p.m., 4 p.m. to 8 p.m., and 7 p.m. to 11 p.m. O&R's CSRP has a single 2 p.m. to 6 p.m. peak window throughout its service territory.

[38] The Downstate Utilities propose to set the payment rates for Con Edison at $10 per kW avoided per month for summer months, and $2 per kW avoided per month during other months. The Downstate Utilities have not proposed specific payment rates for O&R.

[39] The Downstate Utilities propose to set the off-peak incentive level at $0.03 per kWh for Con Edison, but have not proposed a specific level for O&R.

For the adder incentive, the Downstate Utilities propose a structure which would provide a fixed dollar per kW per month incentive which decreases with increasing customer load factor. To illustrate how the adder incentive would work, the Downstate Utilities propose adder incentives beginning at $7.50 per kW charging capability per month at one percent load factor, diminishing by approximately $0.90 per kW charging capability per month for each percentage improvement in load factor to three percent, and diminishing by a further $0.60 per kW charging capability per month for each percentage improvement in load factor beyond three percent, such that the adder incentive is eliminated at load factors at or above 13 percent.[40]

The Downstate Utilities estimate that the CMCP and adder incentives could cost somewhere greater than between $256 million and $324 million, and note that such figure is significantly less than the $800 million in benefits they forecast during the same time period.[41] The Downstate Utilities propose to recover CMCP and adder incentive costs in a similar way to how Make-Ready Program costs are recovered – CMCP costs would be deferred as a regulatory asset, amortized over a 15-year period with carrying costs at the utility's pretax overall weighted average cost of capital, and be recovered through a surcharge mechanism. CMCP program costs would be allocated to

[40] The adder incentive levels at each load factor percentage proposed by Con Edison are shown in Appendix A. The Downstate Utilities have not proposed a specific adder incentive level for O&R.

[41] The Downstate Utilities estimate costs for the CMCP and adder incentives at Con Edison between 2024 and 2028, noting that there will be additional costs the program would be implementing during 2023. The Downstate Utilities also estimate that if the adder incentive is only offered during 2024 the costs for that component would be $16 million, whereas the costs for the adder incentive could be $84 million if implemented throughout 2024 through 2028.

all customers using the transmission and distribution revenues allocator, and would be recovered from demand-billed customers on a per-kW demand basis, and from non-demand billed customers on a per-kWh energy basis.

The Downstate Utilities argue that there are two advantages to amortizing CMCP and adder incentive costs compared to the more contemporaneous cost recovery mechanism recommended in the DPS Staff Whitepaper. First, the Downstate Utilities argue that amortizing the CMCP and adder incentive costs would spread program costs over time, moderating the impact to customer bills during the time when there will be the greatest difference between the recovery of new revenues from EV charging customers and when costs to serve such customers will be incurred.[42] Second, the Downstate Utilities argue that a 15-year cost recovery period would better match the 30- to 50-year useful lifetime of assets related new grid upgrade expenditures which would be potentially be avoided through customer participation in the CMCP.

Conversely, the Upstate Utilities do not support the CMCP as proposed. However, the Upstate Utilities state that implementing a similar CMCP as an Immediate Solution would accelerate DCFC deployment in their respective service territories, arguing that a CMCP which only offers operational savings when EVs are able to be charged during off-peak hours would not address the demand charge issues facing transit and public charging customers, and would therefore be a mismatched solution for the problem facing EV charging customers. The Upstate Utilities posit that a well-designed CMCP with adders

[42] The Downstate Utilities anticipate that incremental grid costs to serve EV charging customers will increase at a faster rate than the rate of incremental revenue growth from EV charging customers in the short term – opposite of the assumptions in the DPS Staff Whitepaper.

could potentially be designed to address the barriers posed by demand charges, but is concerned that such programs would not be able to be implemented in the time provided under PSL §66-s given the need to design the program, procure implementation vendors, and integrate back-office systems to be able to successfully implement a CMCP. The Upstate Utilities state that the CMCP would benefit from a longer planning and implementation period, and propose to work to implement a CMCP to be available for customer participation shortly after the Near-Term Solution is implemented.

Instead of the DPS Staff Whitepaper's recommendation to implement a CMCP, the Upstate Utilities propose an alternate Immediate Solution based on providing a discount against DCFC customers' demand charges (Demand Charge Rebate).[43] Under the Upstate Utilities' proposal, all eligible DCFC chargers, whether public or not, would receive an off-bill financial credit equal to 50 percent of the bill demand charge. The Upstate Utilities propose that DCFC chargers would have to either be separately metered, or able to demonstrate that any non-EV charging demand is inconsequential to the relevant utility's satisfaction, to be eligible to receive the Demand Charge Rebate.

The Upstate Utilities propose to pay for Demand Charge Rebate costs first by using PPI Program funds, then, if necessary, recover costs over and above the remaining PPI Program funds, from customers through a surcharge in a similar manner to how Make-Ready Program costs are recovered. Specifically, the Upstate Utilities propose to defer and amortize incremental Demand Charge Rebate costs above the

[43] The Upstate Utilities described their proposal as the "Operating Cost Incentive Program" in their comments; however, since the proposal is meaningfully similar to that proposed by the JEVIP and other parties, we refer to this proposal as the Demand Charge Rebate.

remaining PPI Program funds over a 5-year period, but do not specify a particular cost allocation and cost recovery proposal.[44] The Upstate Utilities note that to the extent that the PPI Program funds are not exhausted, such funds could be used, as recommended in the DPS Staff Whitepaper, to apply toward incentives for EV load management strategies and technologies.

The Upstate Utilities identify several advantages of the Demand Charge Rebate in comparison to the DPS Staff Whitepaper's proposal to implement a CMCP. The Upstate Utilities argue that the Demand Charge Rebate would directly address the significant barrier that demand charges pose in the upstate area, are supported by members of the EV charging industry and other key stakeholders, would allow a smooth transition to other Near-Term Solutions, and would not result in incremental costs to the extent that the Demand Charge Rebate can be funded through already-collected PPI Program funds.

Response to Stakeholder Concerns

The Downstate Utilities attempt to address several stakeholder concerns regarding use of the CMCP as an immediate Solution as part of their comments. First, the Downstate Utilities recognize concerns about degradation of EV driver experience related to charger availability through perceived requirements to turn off chargers during peak periods, but state

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[44] The Commission interprets the Upstate Utilities proposal to recover incremental Demand Charge Rebate costs "through the Make-Ready Surcharge" as deferring such costs as a regulatory asset, amortizing that balance over a 5-year period with carrying costs at the utility's pretax overall weighted average cost of capital, and recovery of the annual portions through a surcharge mechanism, allocated to all customers using the transmission and distribution revenues allocator, and recovered from demand-billed customers on a per-kW demand basis, and from non-demand billed customers on a per-kWh energy basis.

that the proposed CMCP imposes no such requirements. The Downstate Utilities state that because their proposed CMCP is prorated based on fixed charger nameplate capacity, even station operators that have some on-peak charging will have the opportunity to earn meaningful incentives.

Second, the Downstate Utilities note that some stakeholders have expressed concern that participating in the CMCP will require station operators to implement load management technologies such as batteries or ALM. The Downstate Utilities state that the CMCP would impose no such requirements; however, it would provide additional incentives and revenue opportunities for customers that do deploy load management technologies.

Third, the Downstate Utilities note that some stakeholders expressed concern that the use of multiple different network peak windows would result in program complexity and the need for significant public education campaigns to better inform EV drivers regarding when to charge their vehicles. The Downstate Utilities agree that while managing multiple peak windows may be somewhat more complex, there are significant benefits from such geographic diversity. The Downstate Utilities assert that geographic diversity could be good for charging station operators that are able to direct customers to particular locations through time-variable pricing, thus increasing incentive payments available through the CMCP. The Downstate Utilities also assert that geographic peak window diversity can enable tailoring charger buildout and use in areas where operational use patterns do not coincide with peak periods, resulting in lower localized network costs and benefits to all customers.

Fourth, the Downstate Utilities argue that a 50 percent Demand Charge Rebate is not appropriate for the Con Edison and O&R service territories. The Downstate Utilities argue that a Demand Charge Rebate requiring separately metered EV charging would not accommodate the vast majority of EV charging stations which have already been installed in the downstate area, many of which include significant co-mingling of EV and non-EV load. The Downstate Utilities also argue that a 50 percent Demand Charge Rebate would dull price signals which encourage customers to manage their EV charging demand and establish innovative business models. The Downstate Utilities assert that the 50 percent Demand Charge Rebate is a blunt tool which under-incentivizes EV charging stations at the lowest load factors where operating cost relief is needed most, while over-incentivizing stations at higher load factors.

Near-Term Solutions

Instead of the EV Phase-In Rate Solution proposed in the DPS Staff Whitepaper, the Upstate Utilities propose to implement an EV Rate Program, which would provide off-bill rebates to EV charging customers based on their EV charging load factor, in three graduations, for a period of ten years.[45] In the first graduation, applicable to customers with EV Charging load factor of less than ten percent, the EV Rate Program would provide a monthly off-bill credit equal to 75 percent of a participant's demand charge. In the second graduation, applicable to customers with EV charging load factors greater than 10 percent but less than or equal to 15 percent, the EV Rate Program would provide a monthly off-bill credit equal to 50 percent of a participant's demand charge. In the third graduation, applicable to customers with EV charging load factors greater than 15 percent and less than or equal to 20 percent, the EV Rate Program would provide a monthly off-bill credit equal to 25 percent of a participant's demand charge.

[45] The EV Rate Program, once available, would replace the Upstate Utilities' proposed 50 percent Demand Charge Rebate.

The EV Rate Program would not be available to customers with EV charging load factors of greater than 20 percent.

The Upstate Utilities propose that the EV Rate Program would be available to each participant for a period of 10 years, and the continuing need for the EV Rate Program would be considered as part of the biennial review process recommended in the DPS Staff Whitepaper. If cancelled by the Commission, new customers would not be allowed to begin participation in the EV Rate Program; however, existing participants would be allowed to continue participation in the program for the remainder of each participant's 10-year period. For example, if the EV Rate Program were cancelled by the Commission in 2030, a customer that began participation in the program in 2025 would be allowed to continue participation in the program through 2035; however, customers not already enrolled in the program at its cancellation date would not be allowed to begin participation.

The Upstate Utilities propose to require EV Rate Program participants to separately meter EV charging load as a condition for participating in the program, with exceptions granted for energy storage installed onsite specifically to manage and offset EC charging demand. The Upstate Utilities note that customers with large amounts of intermingled EV and non-EV load are likely to have higher load factors than those required to participate in the EV Rate Program, i.e., greater than 20 percent, and that such customers would not be as significantly impacted by vehicle charging demands compared to customers with EV chargers served by a dedicated utility service. The Upstate Utilities state that the stricter eligibility requirement allows for a deeper demand charge discount for low load factor customers in the first graduation, and allows the EV Rate Program to be administered more easily. The Upstate Utilities assert that the requirement to compute the ratio of ratios of demand from intermingled EV charging and non-EV charging uses is infeasible for many customers and administratively burdensome, issues which could be avoided by requiring separately metering EV charging.

The Upstate Utilities propose to calculate participants' load factors for determining which graduation of the EV Rate Program such customer is eligible for once annually, based on the average of such customer's twelve, monthly load factors.[46] The Upstate Utilities state that their proposed annual load factor computations are superior to the quarterly load factor computations recommended in the DPS Staff Whitepaper, and would result in greater bill stability and predictability for participants.

Instead of the EV Phase-In Rate Solution recommended in the DPS Staff Whitepaper, the Downstate Utilities state that use of updated standby service rates, in combination with a CMCP set at a cost-effective level without use case-specific adders, provides significant operating cost relief for EV Charging customers, and should be approved as a Solution. The Downstate Utilities note that the pending standby rate alone provides meaningful reductions in effective delivery costs at all load factor levels in comparison to the traditional demand rates, and further assert that layering in value-based incentives provided through the CMCP can provide sufficient operating cost relief to EV charging customers.

The Downstate Utilities state that the pending standby service rate both adheres to the objectives and requirements of PSL §66-s, as well as meets four principles identified in the JU for good practice in solution development. Specifically, the

[46] Customers would be defaulted to the first graduation of the EV Rate Program where there is insufficient data to calculate a customer's load factor for a year.

Downstate Utilities state that the Solutions approved by the Commission should: (i) seek to prevent over- and under-incentivization of charging sites; (ii) incentivize charging stations to innovate to improve their load factor; (iii) minimize inadvertent adverse financial consequences of shifting costs to other customers within the same service classes as EV charging customers; and (iv) provide transparent subsidies, including identifying the customers that will bear the costs of the Solutions. As a goalpost for meeting these objectives, the Downstate Utilities state that the objective for Solutions should be to reduce the effective per-kWh delivery cost to a level equivalent to what a charging station operating at 20 percent load factor would pay - approximately $0.24 per kWh in the Con Edison service territory.

The Downstate Utilities note that the per-kWh costs under the pending standby service rates decrease with increasing customer load factor, resulting in incentives for customers to improve their load factor, both with and without incentives through the CMCP. The Downstate Utilities also assert that the combination of the pending standby service rates and CMCP avoid inadvertent adverse financial consequences and shifting of large costs to other customers by providing right-sized incentives to EV charging customers. The Downstate Utilities argue that the CMCP, in combination with the pending standby service rates, provides a transparent provision of incentives to EV charging customers, and that, if desired, the Commission could choose to increase CMCP incentive payments to help further boost the EV charging market while maintaining cost-effectiveness of the program. The Downstate Utilities note that while the DPS Staff Whitepaper expressed concern over use of the standby service rates as a potential Solution, the results of the Downstate Utilities' analysis suggests that the pending standby service rates provide sufficient operating cost relief even under worst-case scenarios where standby service contract demand amounts were set to the maximum charging demand levels. Finally, while the Downstate Utilities acknowledge that the pending standby service rates are still undergoing Commission review, final standby service rates will likely be available for customer participation prior to a new, yet-to-be-designed EV Phase-In Rate Solution would become available.

Feedback on EV Phase-In Rate Solution

Although the JU prefer alternate Solutions, the JU also provide specific comments related to the EV Phase-In Rate Solution recommended in the DPS Staff Whitepaper. First, the JU propose that the EV Phase-In Rate Solution be redesigned to require a portion of demand charges imposed in the first graduation. The JU argue that by requiring no demand charge element in the first graduation, there would be no incentive for customers to manage demand, whereas introducing some level of demand charges in the first graduation is necessary to instill customer behaviors to manage demand. The JU request that if the Commission does introduce some level of demand charge element in the first graduation of the EV Phase-In Rate Solution, it should also consider changes to the level of demand charge elements in the later graduations as well.

Second, instead of computation of a single annual load factor, as recommended in the DPS Staff Whitepaper, the JU request the Commission instead approve a computation of the load factor used for determining which EV Phase-In Rate Solution a participant is eligible for based on the annual average of the participant's monthly load factors.[47]

[47] Instead of calculating the annual load factor by dividing the sum of annual kWh energy usage by the product of the maximum annual demand kW and 8760 hours (or 8,784 hours during a leap

Third, the JU argue that the quarterly computations of load factor recommended in the DPS Staff Whitepaper would be administratively burdensome, and would result in customer confusion and complaints because an EV Phase-In Rate Solution participant could be moved between graduations as frequently as four times per year. The JU assert that the potential to change graduations so frequently will result in uncertainty for customers regarding which graduation they will be placed in throughout the year, significantly challenge customers' ability forecast charging costs and budget for the year, and would also require administratively burdensome manual processes or significant automation for utilities to move customers between graduations. The JU argue that their proposed methodology using the average of 12 monthly load factors is more reasonable as it better reflects the impacts of customers with seasonal variations in load.[48]

Fourth, instead of allowing all customers with up to 50 percent non-EV load to participate in the EV Phase-In Rate Solution, as recommended in the DPS Staff Whitepaper, the JU propose instead that participation in the EV Phase-In Rate Solution should require that customers separately meter EV charging load, with exceptions for small amounts of ancillary non-EV load. The JU also propose to allow customers with co-located behind-the-meter energy storage systems, up to 50 percent of the total metered load, to participate in the EV Phase-In Rate Solution. The JU assert that the Upstate Utilities are presently unable to collect the metered data necessary to determine if up to half of the metered load is non-

year), the annual average load factor would be determined based on the average of the 12 monthly load factors.

[48] For example, customers in areas frequented by tourists in the summer months with little winter load.

EV load to determine eligibility for the EV Phase-In Rate Solution, as recommended in the DPS Staff Whitepaper; whereas the Downstate Utilities argue that while they are capable of collecting such data, performing this eligibility check on an ongoing basis would be administratively burdensome. The JU further note that time will be needed to collect and validate EV charging data to needed to determine whether customers meet the DPS Staff Whitepaper's recommended 50 percent criterion.

Fifth, the Joint Utilities disagree with the DPS Staff Whitepaper's recommendation to implement geographically-based super-peak periods which are "relevant to the local needs of the grid." The JU state that while geographically-specific periods are reasonable for the CMCP, applying different super-peak periods within a utility's service territory would introduce an unnecessary degree of complexity in administering the EV Phase-In Rate Solution. Instead, the JU suggest that the Commission adopt a single super-peak period applicable within each utility service territory.[49] The JU note that implementation of a rate design with geographically-varying peak windows will require time to collect EV charging data, including the potential for seasonal variations, beyond even the regular regulatory approval timeline.

Sixth, the JU agree with the DPS Staff Whitepaper's recommendation to evaluate the EV Phase-In Rate Solution as part of the biennial review process. The JU caution, however, that if the Commission decides to cancel the EV Phase-In Rate Solution as part of such biennial review process, it should be careful to consider impacts to bill continuity for existing EV Phase-In Rate Solution participants, and should also consider

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[49] The super-peak period would be applicable to an entire utility service territory, but may be different from utility to utility.

the possible need to continue discounts for customers with low load factors, particularly in rural areas.

The JU assert that the Commission should not ignore programmatic Solutions in favor of tariff-based rate options. The JU note that programmatic Solutions can be offered expeditiously following a Commission Order, and would require a faster and less complex implementation period than an equivalent rate-based tariff Solution. The JU note that there are significant time and expense costs associated with developing and implementing new tariff-based rate Solutions, and that the more complex the rate design, the longer and more costly it will be to implement such rate. The JU estimate that the EV Phase-In Rate Solution as recommended in the DPS Staff Whitepaper would not be available for customers to participate in until at least 2025.

Notwithstanding the Joint Utilities' comments on the design of the EV Phase-In Rate Solution, the Downstate Utilities stridently argue against implementation of the EV Phase-In Rate Solution in favor of their preferred Solution consisting of standby service rates and incentives through the CMCP. The Downstate Utilities note that customers are already capable of responding to price signals provided under traditional demand rates. The Downstate Utilities note that Revel has implemented load management technologies and processes to manage its charging load at its publicly-accessible 25 DCFC charging station in Brooklyn, achieving total electricity costs of approximately $0.20 per kWh, meaningfully below the Downstate Utilities delivery-only target cost of $0.24 per kWh.

The Downstate Utilities argue that the EV Phase-In Rate Solution materially over-incentivizes charging stations by pushing delivery costs well below the 20 percent load factor equivalent cost, and such impact is further enhanced with the addition of incentives provided under the CMCP. The Downstate Utilities note that the combination of EV Phase-In Rate Solution and CMCP incentives may result in zero delivery costs in some instances, which in turn would require the utilities to develop CMCP incentive payments both for customers participating in the EV Phase-In Rate Solution and customers that do not to avoid distortionary price impacts. The Downstate Utilities observe that the EV Phase-In Rate Solution results in lower charging costs between 10 to 20 percent load factors in comparison to load factors above the 20 percent cutoff, and argue, therefore, that the EV Phase-In Rate Solution does may result in customers persistently relying on the program instead of continually seeking to improve their load factors.

The Downstate Utilities argue that over-incentivization through the EV Phase-In Rate Solution would provide an excess of cost savings to EV charging customers at the expense of other customers. While the Downstate Utilities agree with the DPS Staff Whitepaper's assertion that cost shifts would only occur when the incremental grid costs imposed by EV charging customers exceed the incremental revenue collected from such customers, the Downstate Utilities assert that, based on an analysis performed for the Con Edison service territory, they anticipate that incremental grid costs due to EV charging would roughly double the revenues collected from EV charging customers participating in the EV Phase-In Rate Solution.[50] The Downstate Utilities also warn that the magnitude of the cost shift may

[50] Con Edison's analysis is based on the High Distribution Impact Case Unmanaged Charging Scenario of NYSERDA's Transmission Electrification Distribution System Impact Study (TEDI Study), plus estimates for New Business costs. The Downstate Utilities state that while the analysis is only applicable to the Con Edison service territory, similar results are expected for the O&R service territory as well.

increase if EV station develop occurs more rapidly than presently anticipated, and that a tariffed rate design-based solution may be more difficult to change once implemented, locking in cost-shifts for a longer period than would be feasible for a programmatic approach.

Specifically, the Downstate Utilities estimate that the total cost shift borne by non-EV charging customers would be between $750 million to $1.6 billion through 2030, assuming that all EV charging stations choose to participate in the EV Phase-In Rate Solution.[51] As a point of comparison, the Downstate Utilities note that they estimate that the cost of the CMCP for Con Edison through 2030 would be approximately $440 million. The Downstate Utilities further observe that, in addition to not covering the incremental costs of new infrastructure through incremental revenues, new EV charging customers participating in the EV Phase-In Rate Solution would also not contribute to the costs of the existing infrastructure they would use. The Downstate Utilities warn that future Embedded Cost of Service studies would allocate these new grid costs to all service classes, potentially impacting residential and other service classes beyond those that EV charging customers would be part of.

Responses to Specific DPS Staff Whitepaper Questions

The JU provided feedback on the questions posed to stakeholders in the DPS Staff Whitepaper. First, in response to the DPS Staff Whitepaper’s question regarding what format each type of CMCP incentive adder should take, the JU note that adders are not appropriate for the Upstate Utilities where implementation of a CMCP would be challenging in the short

[51] The Downstate Utilities estimate that the cost shift could be twice as high in the most extreme case of up to 50% of non-EV charging load participating in the EV Phase-In Rate Solution.

term.[52] Second, in response to the DPS Staff Whitepaper's question regarding the most appropriate venue for Commission consideration of whether to include EV charging customers within existing commercial service classes or to segregate such customers into a separate EV charging service class, the JU state that the present statewide proceeding is the appropriate venue for such decisions. Third, in response to the DPS Staff Whitepaper's request for input on the EV Phase-In Rate Solutions graduations and proportion of revenues to collect through demand charge components, the JU reiterate their position that some revenues should be collected through demand-based charges in all graduations.

Fourth, in response to the DPS Staff Whitepaper's question regarding the potential for interference between standby service and the EV Phase-In Rate Solution for customers that install energy storage technology to help manage charging loads, the JU state that they do not see any interference between standby service and the EV Phase-In Rate Solution. The JU propose that EV charging customers paired with energy storage systems should have the option to be exempt from paying standby service rates provided that the charging station meets all eligibility requirements of the EV Phase-In Rate Solution, that the energy storage inverter nameplate capability is less than or equal to the EV charger nameplate capability, and that the energy storage system meet all other interconnection and non-rate requirements needed for standby service.[53]

[52] The Downstate Utilities proposed adders are described above.

[53] That is, an energy storage system with inverter nameplate capability greater than the customer's maximum EV charging capability would not be exempt from standby service and the associated rates.

Finally, in response to the DPS Staff Whitepaper's question of whether the Commission should consider requiring utilities to offer supply service charges specifically designed for EV charging customers, the JU recommend that the Commission limit the scope of immediate- and near-term Solutions to those related to delivery service demand charges. The JU state that this limitation is reasonable as delivery service demand charges are the focus of PSL §66-s, and limiting the scope of this proceeding to delivery charges will most directly and effectively address market concerns.

League of Conservation Voters

The League of Conservation Voters notes that many New Yorkers who live in multi-unit dwellings (MUDs) rely primarily on public DCFC stations to charge their vehicles, stating that a recent study demonstrates that approximately 43 percent of MUD residents rely on DCFC as their primary means of charging, a rate approximately three times as high as non-MUD residents. While the League of Conservation Voters states that it is optimistic regarding the EV Phase-In Rate Solution proposed in the DPS Staff Whitepaper, it is concerned that the interim solution of implementing a CMCP would offer little relief to public charging stations in the near term.

The League of Conservation Voters states that it is primarily concerned that the recommended CMCP's demand-based peak avoidance incentive will have detrimental effects on public DCFC station operations. The League of Conservation Voters argues that to maximize the benefit of the peak avoidance incentive, public DCFC operators will have to limit the times when customers are able to charge their vehicles or reduce power for charging during peak hours, disproportionately and negative affecting EV customers that live in urban areas, who do not have access to off-street parking, and who have already been slow to enter the EV market. The League of Conservation Voters notes that any disincentive to charge at certain times would overly burden users who rely on fast charging the most, and would encourage DCFC station operators to pass on operational and financial burdens on to the most vulnerable users.

The League of Conservation Voters states that the five- to ten-percent reduction in demand charges provided through the CMCP as estimated by Con Edison and referenced in the DPS Staff Whitepaper is not sufficient to address the barrier presented by demand charges.[54] The League of Conservation Voters points to programs approved in other states as a model for New York, including "bridge rates" to serve as interim Solutions while permanent EV rates are developed. The League of Conservation voters identifies programs in Connecticut, which converted demand charges to service class average equivalent per-kWh energy rates, and Maryland, where a 50 percent demand charge discount was provided. The League of Conservation Voters asserts that similar bridge rates would provide more meaningful and immediate relief from demand charges than the DPS Staff Whitepaper's proposed immediate solution to implement a CMCP.

MTA

MTA agrees with the DPS Staff Whitepaper's statement that EV charging demand is anticipated to be a relatively small portion of overall load in the short-term. Because of this, MTA states that the rationale for meaningful demand charge relief is valid and strong. MTA comments that the Commercial Managed Charging Program proposed by Con Edison and Orange and Rockland offers only a negligible adjustment to the demand charge schemes that are already in place which would do little to defray the

[54] The reduction referenced in the DPS Staff Whitepaper was without the impact of use case specific adders.

sharp escalation in operating costs it would face if running an electric bus fleet.

MTA posits that other states which have concluded EV charging load is unlikely to place undue stress on power network peaks for the next few years have put in alternatives to traditional demand charges. MTA points to California and Florida as example of states with less stringent greenhouse gas emissions policies that provide considerably more operating cost relief than DPS Staff's proposal. MTA suggests the proposed 'Solution', which requires significant investment in energy management capability, would be as effective at creating new barriers for fleet operators as it would be at removing existing ones.

MTA posits that the DPS Staff Whitepaper, as well as the Guidehouse report, focuses on the economics of publicly accessible DCFCs to the detriment of commercial and transit fleets. MTA's preliminary modeling finds that the recommended CMCP would result in far higher cost to operate an electrified fleet compared to its current predominantly diesel and gas vehicles. MTA comments that such a major cost escalation will undoubtably harm the MTA's ability to provide services in Potential Environmental Justice Area (PEJA) communities, possibly resulting in cutbacks, increased customer fares, and deferrals of other customer service-oriented initiatives for people who depend upon the MTA for transportation, counter to the CLCPA's focus on supporting such communities.

MTA recommends that to resolve this oversight, the Commission should require that the State's investor-owned utilities implement a rate solution in the near term, that either temporarily eliminates the traditional demand charge component or greatly reduces it, as other jurisdictions have done. Furthermore, the MTA recommends that the Commission should require that the future phase-in Solution meaningfully remove cost barriers for fleet operators, which may include establishing a particular rate for electrified fleets that will make operating costs comparable or lower than those for diesel or natural gas fleets.

NRDC and Sierra Club

NRDC and Sierra Club assert that achieving cost savings for charging EVs in comparison to filling gasoline- or diesel-fueled vehicles is among the most important metrics New York's transportation electrification policy goals. NRDC and Sierra Club state that achieving fuel savings is critical to the total cost of ownership metric that fleet customers consider when deciding whether the electrify their fleet vehicles, is also critically important to drivers deciding whether to purchase an EV compared to an internal combustion engine vehicle, and potentially exacerbates equity issues between drivers who do not have access to residential charging and must therefore rely on public charging to fill their vehicles. NRDC and Sierra Club state that traditional commercial and industrial (C&I) demand rates were not designed to reflect the unique nature of EV charging, and that the cost of EV charging often exceeds the cost of filling up with gasoline or diesel under traditional demand rate structures. NRDC and Sierra Club state that redesigned EV-specific charging rates that more accurately reflect the flexible nature of EV charging in comparison to traditional commercial and industrial electric loads and provide meaningful reductions in monthly EV charging costs would help promote widespread transportation electrification, improve utilization of the electric grid, put downward pressure of utility rates for the benefit of all utility customers, and help New York achieve its climate, equity, and air quality goals.

NRDC and Sierra Club recommend that modifications should be made to the DPS Staff Whitepaper's proposed rate-design based solution to C&I rates. NRDC and Sierra Club assert that the DPS Staff Whitepaper did not fully consider rate design options in place in other states which are based on setting rates based on marginal costs initially, with a gradual and predictable ramp-up to full embedded costs. NRDC and Sierra Club point to two such rate design options approved in Alabama, which provides for discounted electric rates initially as low as 110 percent of the applicable marginal cost with a set ramping-up period, and in California, which collects only the utility's marginal costs during the first year of participation and ramps up to the full embedded cost rate by year 11.[55] NRDC and Sierra Club state that the California commission found that the initial marginal cost approach proves significant fuel cost savings that incentivize greater commercial EV adoption without subsidizing EV charging or shifting costs to other customers.

NRDC and Sierra Club assert that the virtuous cycle described in the DPS Staff Whitepaper, where new EV load entering the system helps reduce rates for all customers, which in turn encourages greater EV load, will not be realized if the rate design-based solution is not competitive or advantageous compared to gasoline prices. NRDC and Sierra Club request that the Commission modify the DPS Staff Whitepaper's recommended EV Phase-In Rate Solution to better align with the underlying marginal costs of charging, by recovering only marginal costs in the first year that the rate is open to customer enrollment and linearly phasing in recover of non-marginal costs over 10

[55] The Economic Development Incentive program at Alabama Power is functionally similar to existing economic development rate programs already in place in New York, such as Con Edison's Business Incentive Rate program.

years.[56] NRDC and Sierra Club state that as long as the modified EV Phase-In Rates are set to recover at least marginal costs, existing customers will bear no additional costs from bringing new EV charging load onto the system, while benefitting in the long term from downward pressure on rates.

NRDC and Sierra Club state that they support the DPS Staff Whitepaper's recommended quarterly and annual reporting requirements, and agree with the recommendation to begin a periodic review process. NRDC and Sierra Club recommend that the Commission require utilities to report the percentage of charging occurring during peak, off-peak, and super peak times in addition to the other metrics already required in the quarterly and annual reports. NRDC and Sierra Club assert that reporting this additional aggregated customer data would enable the Commission and stakeholders to evaluate whether the proposed energy charges and TOU periods are effective in accomplishing their goals, or whether to modify them.

NY-BEST

NY-BEST concurs with DPS Staff's recommendation to require a CMCP as a reasonable, timely and near-term method to offset barriers posed by traditional demand charges. NY-BEST also agrees with the DPS Staff Whitepaper's proposal to redeploy remaining PPI Program funds toward eligible load management strategies including Automated Load Management software and on-site or charger integrated energy storage. NY-BEST recommends that the Commission direct utilities to include bi-directional chargers as eligible load management equipment in all Commercial Managed Charging Programs. NY-BEST recommends that the added

[56] It is unclear from NRDC and Sierra Club's comments whether the linear phase in toward full embedded costs would occur for all customers on a set schedule, similar to the discounts approved as part of the PPI Program, or if each customer would be eligible for a 10-year period beginning upon enrollment.

incentive for energy storage, bi-directional chargers, and other ALM approaches would be most effective in the form of upfront incentives for qualifying measures both for hardware and software.

NY-BEST is supportive of the recommended TOU energy rate and graduated return to demand charges tied to site utilization as an effective approach. NY-BEST strongly supports the proposed structure that includes a super-peak period of no longer than four hours with energy charges of 3-5 times off-peak rates, however, NY-BEST asserts a modification of demand charge windows would provide significant benefits to both site operators and EV drivers and would hold true to principles of cost causation.

NY-BEST continues to support narrowing the demand charge period to a four-hour period coincident with system peak hours to more fairly allocate costs of charging during local system peaks. NY-BEST argues that the present 14-hour demand charge window applicable to utility commercial tariffs is too long to be effectively managed by either most technical solutions or by adjustments to EV charging behaviors. NY-BEST asserts that if demand charge window times are not narrowed to coincide with the super-peak periods of the TOU rate, the effect of the TOU rate will be diluted by mixing a four-hour TOU peak period with a fourteen-hour demand charge window, completely eliminating the highly beneficial super-peak window at load factors greater than 20 percent. NY-BEST recommends that the Commission order utilities to develop and implement an optional super-peak demand charge that mirrors the TOU timing structure and time-related cost recovery that can be used in place of present conventional demand charges for each of the three EV Phase-In Rate Solution graduations, as well as above the 20% load factor threshold.

NYPA

NYPA notes that demand charges are particularly challenging for public DCFC stations where consumer usage patterns are unpredictable and where there may be only a single metering interval where the charging station reaches peak billable demand during a given month. NYPA notes that demand charges are somewhat less challenging for transit and fleet operators, which have more predictable usage that can be charged at night, however, such customers may have to charge during the mid-day period for operational purposes and specified off-peak periods may be too short for operators to fully charge their entire fleet during.

NYPA states that the Commission should approve the proposed CMCP and EV Phase-In Rate Solution with certain modifications. NYPA requests that the Commission consider the potential impacts of imposing time-varying rates on public chargers, which could then either be passed on to customers in the form of higher charging prices or slower charging speeds during on-peak periods. NYPA asserts that the EV adoption rate in New York needs to accelerate rapidly to meet the State’s policy goals, and to accomplish this public EV charging must be convenient, consistent, and easy to understand and use. NYPA asserts that, since most internal combustion engine vehicle drivers are not accustomed to having to determine when to refuel based on the time of day, or day of the week, higher on-peak electricity costs passed from station operators on to EV drivers would act as a disincentive against purchasing an EV. Similarly, NYPA notes that reductions in charging speeds implemented by station operators to avoid high demand charges could result in poor consumer experience and thus disincentivize purchases of EVs. NYPA asserts that any incentive, rate, or discount should be implemented with the consideration that public chargers will not be able to reduce their demand during peak hours by charging higher rates.

NYPA states that it supports the CMCP as an interim measure for fleet charging, but recommends that the Commission consider increasing the duration of the off-peak charging incentive to correlate with the needs of fleet operators. NYPA states that, based on its own experience and through conversations with other fleet and transit customers, an off-peak period of at least 9 p.m. to 6 a.m. is needed to ensure that transit customers are able to fully charge during the off-peak period, but notes that some transit authorities suggest a longer 12-hour off-peak period. For public DCFC customers, NYPA requests that the Commission adopt a simplified off-bill Demand Charge Rebate for public DCFC charging, as proposed by Electrify America during the November 4, 2022 stakeholder session, instead of the CMCP as recommended in the DPS Staff Whitepaper. NYPA asserts that the Demand Charge Rebate is a simple and easy to implement proposal that would provide relief to public EV chargers and avoid incentives for public DCFC station operators to either decrease charging speeds or pass on time-varying rates to EV charging consumers during peak periods.

NYPA states that it supports the proposed EV Phase-In Rate Solution but requests that the Commission require the utilities to provide more detail on the specific rates and charges designed and provide sample EV charging customer utility bill calculations to stakeholders to elicit feedback before approval of any such rates. NYPA further states that it is concerned with the potential for a long and complicated development and implementation timeline for the EV Phase-In Rate Solution, given utility comments at the November 4, 2022 stakeholder session that similar pilots have taken as long as two years to implement. NYPA requests that the Commission pay attention to the timeline in implementing any EV Phase-in Rate, as a long implementation period would not provide the immediate short-term relief needed during the early years where station utilization remains low.

Revel

Revel is supportive of incentives that bring down costs for all entities, while not distorting market signals or only benefiting underutilized stations, and support incentives that reward customers for helping maintain a stable electrical grid. Revel points to Con Edison's Managed Charging Program as an example that encourages beneficial grid behavior by rewarding operators who reduce demand during peak grid congestion which reduces costs for all ratepayers.

Revel also supports incentive adders which encourage technology and business innovation without distortionary price signals subsidizing inefficient operators. Revel points to its own experience operating the largest public charging site in the Americas under existing demand charges. Revel notes that through its combination of public charging and use of load management technology and using its charging capacity for its own fleet, it has been able to reduce per-kWh charging costs from $0.65 per kWh to approximately $0.20 per kWh. Revel notes that it made these investments because the existing rate structure provided a strong incentive to do so, and that distortion of such price signals could reduce investment and innovation to improve load factors, increase grid costs borne by customers, compromise grid stability, and limit the long-term viability of EV charging as a sustainable business model. Revel suggests that the benefits and costs of any adders should be reviewed after an allotted time period and revised, if necessary, to ensure that such adders are having the intended effect, and not being abused or creating large market inefficiencies.

TeraWatt

TeraWatt Infrastructure (TeraWatt) states that it is a project developer that owns, operates, and provides high-powered EV charging solutions for light-, medium-, and heavy-duty commercial fleet vehicles. TeraWatt states that fueling costs are often a major determinant in timeline and investment decisions for fleet operators, that electricity costs can be higher and more variable than other traditional fuel types, and that traditional demand charges can be one of the most significant costs of electric fueling. TeraWatt states that it is supportive of work to develop alternatives to traditional demand charge rates, and asserts that alternate rate designs along with managed charging incentives can provide benefits in accelerating conversion of vehicles to EVs and the associated buildout of EV charging infrastructure.

TeraWatt states that while the DPS Staff Whitepaper's recommended CMCP incorporates elements that seek to address upfront and ongoing costs barriers posed by traditional demand rates, the incentives provided under the CMCP may be difficult for certain fleets that may need to charge on-the-go during peak periods, particularly ride-hailing and taxi fleets, to make use of. TeraWatt states that while it is supportive of the intention behind encouraging demand charge management and load shifting, where possible for fleet applications, the four-hour peak windows which customers need to avoid are operationally prohibitive for some fleets, and therefore the recommended CMCP does not meet the intended purpose of addressing rate structures for multiple fleet types.

TeraWatt states that it has tried to model several scenarios to capture the value of incentives provided under the

CMCP, including installation of on-site energy storage. TeraWatt concludes, however, that installing energy storage would increase overall annual operating costs by approximately 20 percent. TeraWatt recommends that additional work to develop alternate programs and rate options continue to help provide proper price signals that a variety of commercial fleets, including those that do not have the flexibility to shift load during certain hours of the day, can use.

Uber

Uber states that it supports the EV Phase-In Rate Solution recommended in the DPS Staff Whitepaper, and asserts that the EV Phase-In Rate Solution will provide strong long-term support of the EV industry and New York's transition to electric transportation. Uber expresses concern, however, that the DPS Staff Whitepaper's recommended CMCP will prove ineffective. Uber asserts that widespread adoption of EVs will require expanding the EV sales to customers that live in MUDs, who many not have access to consistent parking or charging at home, especially in dense urban areas. Uber states that a recent University of California study found that approximately 43 percent of MUD residents rely primarily on public DCFC as their source of charging. Uber states that traditional demand charges not only pose a barrier to charging station economics, but also result in higher charging costs for consumers that rely on public charging compared to those that are able to charge at home.

In particular, Uber disagrees with the DPS Staff Whitepaper's recommended demand-based peak avoidance incentive. Uber states that the potential benefits of the program, approximately a 5- to 15-percent reduction in demand charge costs, would provide meaningful demand charge relief for station operators. Uber argues that, under the CMCP, charging station operators may be forced to limit the hours during which the public can charge their vehicles, or may have to reduce charging power during peak periods. Uber asserts that access to DCFC stations must be at least as convenient as the comparable process of gasoline refueling, and that any measures which could limit the hours during which a consumer can charge an EV at a public station would result in additional barriers for consumers that already have limited access to charging.

Uber points to interim Solutions while permanent EV rates are developed in other states as a model for New York, particularly in Connecticut, which converted demand charges to service class average equivalent per-kWh energy rates, and Maryland, where a 50 percent demand charge discount was provided. Uber asserts implementing a 50 percent reduction in demand charges would more meaningful and immediate relief than the DPS Staff Whitepaper's proposed immediate solution to implement a CMCP.

VGIC

VGIC is generally supportive of DPS Staff's proposal for immediate implementation of the CMCP followed by an EV Phase-In Rate Design Solution. VGIC also expresses support of other DPS Staff Whitepaper's recommendations including allowing charging sites that are either EV load separately metered or intermingled with other site load, as well as the DPS Staff Whitepaper's proposal to redeploy PPI Program funding for energy storage, ALM, and other demand management technologies. VGIC notes that the ALM adder should be targeted towards offsetting the incremental upfront costs of the hardware or software necessary to install ALM at the front end, and asserts that the added incentives for energy storage and other ALM approaches should, therefore, be in the form of an upfront incentive. While VGIC notes that the use of ALM can help the EV charging site not only reduce ongoing costs associated with peak demand, but also mitigate the amount of distribution (i.e., make-ready) infrastructure upgrades needed, however VGIC asserts that incentives toward reduction of make-ready costs may be best suited for the ongoing Make-Ready Program midpoint review process.[57]

VGIC states that the adder for public chargers and chargers in remote locations should be in the form of an incentive discount on the customer’s monthly demand charges as this would be the most straightforward mechanism to provide relief. VGIC states this format is similar to the Demand Charge Rebate proposed by the Upstate Utilities and Electrify America. VGIC maintains that incorporating a demand charge discount into the CMCP, as opposed to replacing the CMCP with a demand charge discount, will help maintain incentives for load management and help reduce grid impacts of EV charging.

VGIC urges the Commission to explore additional rate options for EV customers, including dynamic pricing for both distribution and supply components, in addition to the EV Phase-In Rate. VGIC states that more dynamic pricing, on both the delivery and supply portions of the customer bill, can help incentivize greater load flexibility from EV charging customers and can provide significant savings for EV customers who can align their charging with periods with little to no grid constraints. VGIC recommends that the Commission direct utilities to offer EV customers a real-time pricing option for supply, and that distribution demand charges that are based on

[57] Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure, Notice of Meeting and Commencement of the Make-Ready Program Mid-Point Review, (filed August 30, 2022).

average daily demand or measured only during a narrow peak period (e.g., 4 hours) should be explored.

VGIC recommends that the Commission expand the exemption from standby service rates for customers that install certain energy storage systems to all EV charging customers. VGIC asserts that large charging stations that would be eligible to participate in the EV Phase-In Rate Solution, such as medium- and heavy-duty fleet charging or large public DCFC sites, could be deterred from installing energy storage systems if doing so would be default them instead to standby service rates. VGIC states that an exemption from Standby Service rates is warranted for EV customers who install energy storage.

WattTime

WattTime is excited to see DPS Staff’s recognition that incentives in this program can be based on emissions and supports the recommendation to keep the CMCP in place after the new EV Phase-In Rate. WattTime recommends these proposed incentives be determined based on temporally- and geographically-granular, time-varying, marginal emissions rates because they better identify emission impact. WattTime reasons that because emissions on the grid change frequently, a program that includes incentives for reducing emissions should align with these granular changes.

WattTime states marginal emissions reflect the impact of adding or changing load on the electric grid by identifying the emissions caused by the units responding to a change in load, and asserts that information can be used to move load to the cleanest periods and optimize charging behavior. WattTime recommends using regionally-specific marginal emissions to achieve the greatest emissions reductions from CMCP. Emissions fluctuate based on where electricity is consumed, which should be used to inform flexible load management. The CMCP can be used to tap into moments of renewable energy oversupply to alleviate issues with over generation.

WattTime notes that there are several reliable sources of marginal emissions available, including from: (1) NYSERDA, which uses detailed grid price information combined with fuel and emissions data to calculate marginal emissions based on the expected heat rate of the marginal unit; (2) New York City's Local Law 97, which uses a TOU pathway that relies on marginal emissions calculations based on the expected heat rate of the marginal unit to calculate compliance with the law; and (3) potential future release of marginal emissions data by the NYISO or the Federal Energy Information Administration. WattTime suggests that the presence of these sources for marginal emissions data should give the Commission confidence that data would be available to include in incentives for the Commercial Managed Charging Program, and notes that a similar program in California shows it is possible to administer an incentive based on granular emissions data.