August 20, 2021

VIA ELECTRONIC FILING

Hon. Michelle Phillips
Secretary to the Commission
New York State Public Service Commission
Empire State Plaza, Agency Building 3
Albany, New York 12223-1350

Re: Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources

Dear Secretary Phillips:

Advanced Energy Economy Institute (AEE Institute) and the Alliance for Clean Energy New York (ACE NY) submit for filing their joint comments in response to the August 5 *Notice Extending Comment Period* on the Joint Utilities' Alternative Proposal for an Allocated Cost of Service Methodology*.*

Respectfully Submitted,

Daniel Waggoner
Director
Advanced Energy Economy

Comments on the Joint Utilities' Alternative Methodology for Allocated Cost of Service Studies Used to Develop Standby and Buyback Service Rates (15-E-0751)

Advanced Energy Economy Institute
Alliance for Clean Energy New York

Introduction

Advanced Energy Economy Institute (AEE Institute) is submitting these Comments in response to the Joint Utilities' Proposal for an Alternative Allocated Cost of Service (ACOS) Study Methodology ("JU Proposal"). In order to respond to the JU Proposal, AEE Institute is working with Advanced Energy Economy[1] and the Alliance for Clean Energy New York[2] (ACE NY) to craft the comments below. These organizations are referred to collectively in these comments as the "advanced energy companies," "we," or "our."

Advanced energy companies appreciate the Commission's continued focus on more closely aligning standby and buyback rates with cost causation and preparing these rates to better support the attainment of New York's clean energy goals. Overall, we believe the JU Proposal fails to live up to the goals of this proceeding: to move away from negotiated cost allocations for standby and buyback rates and develop a methodology that aligns as closely as possible with the real impacts of customer usage on system costs. Instead, the JU Proposal would predetermine the outcomes of the ACOS methodology by negotiation, and in most regards, drive the methodology further away from adherence to cost causation. However, there are two elements of the proposal (namely relating to the treatment of costs in higher voltage levels and the use of the allocator for secondary voltage systems) that do independently move the methodology Staff proposed in December 2020 ("Staff Methodology") closer into alignment with cost causation. We urge the Commission to reject the JU Proposal as a whole, but independently consider the merits of and adopt two of the elements of the proposal as it contemplates stakeholder recommendations on the Staff Methodology.

[1] AEE is a national business association representing leading companies in the advanced energy industry. AEE supports a broad portfolio of technologies, products, and services that enhance U.S. competitiveness and economic growth through an efficient, high-performing energy system that is clean, secure, and affordable.

[2] ACE NY's mission is to promote the use of clean, renewable electricity technologies and energy efficiency in New York State, in order to increase energy diversity and security, boost economic development, improve public health, and reduce air pollution.

The current effort to reform how utilities establish their local and shared cost allocations has its origins in the 2016 "REV Track 2 Order"[3] and began in earnest in 2018 with a Staff Whitepaper on Standby and Buyback Rate Design[4] proposing that the utilities conduct Allocated Cost of Service studies (ACOS studies). Many stakeholders wanted to move away from negotiated values for local and shared cost allocations to a methodology that attempts to more accurately align the apportionment of costs with the actual deployment and use of distribution assets on utility systems. The JU Proposal departs from those goals by predetermining how costs would be treated within the Staff Methodology decision tree and by making numerous modifications that reflect negotiation positions where no attempt has been made to provide rationale for those changes or how those changes would better align with the actual use of the system or cost causation. The JU Proposal, in essence, would modify the methodology to produce a desired outcome rather than improve the methodology to better reflect cost causation. After a three-year effort of Staff and stakeholders to arrive at rates based on principles of cost causation, the end result would be nearly the same as our starting point: rates that are a product of negotiation.

Advanced energy companies are strong proponents of the theoretical underpinnings of the Commission's standby and buyback rate design. Contract-demand charges ensure recovery of costs incurred to serve a specific customer, thereby ensuring that a reduction of load does not result in those sunk, local costs being unfairly shifted to other customers. At the same time, by requiring that all costs that could be reduced by an injection of power or a decrease in demand are included in shared costs, standby rate design appropriately rewards targeted demand reductions and injections of power by reducing bills commensurate with system cost reductions. However, for standby rates to function as intended, cost allocations must be accurate. Local cost allocations that encompass the cost of shared distribution facilities nullify the financial benefit of demand reductions to customers, and in the case of power injections, can result in additional charges assessed to customers for the very benefit they provide.[5] An ACOS methodology that closely reflects the actual use and deployment of assets on the utility system is critical to turning the promise of standby and buyback rates into reality.

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[3] Order Adopting A Ratemaking and Utility Revenue Model Policy Framework, Case 14-M-0101, May 19, 2016, at 127-132.

[4] *Whitepaper on Standby and Buyback Service Rate Design and Residential Voluntary Demand Rates*, 15-E-0751, December 12, 2018.

[5] For further explanation of the impacts of inaccurate cost allocations on customer behavior and state policy goals, please see our comments on the Staff Whitepaper on ACOS methods, filed in this proceeding on March 8, 2021 at page 2.

Comments on JU Alternative Methodology

While advanced energy companies urge the Commission to reject the JU Proposal in general, as we have stated above, two elements of the proposal, when considered in isolation, improve the methodology's adherence to cost causation when compared to the JU's previous interpretation of the Staff Methodology as filed in their workpapers on March 8, 2021 ("March Workpapers"). For example, one of our areas of concern with the JU's March Workpapers was the higher allocation to local costs for secondary voltage customers. This produced a counterintuitive result: while primary voltage customers with their own pad-mounted transformers would receive local cost allocation percentages mostly in the single digits, residential customers in Con Edison's territory, who usually share line transformers with tens of other customers or more, would face higher local costs than the utilities initially proposed in their first ACOS studies filed in October 2019 and January 2020.[6] The JU, to their credit, have addressed this shortcoming by making several changes that not only produce a more rational result for secondary voltage customers but also adhere more closely to the actual function and design of electric grids and principles of cost causation. However, the JU have also made further changes that, in other aspects, take the ACOS methodology much further away from alignment with cost causation, which is why we ultimately decided to recommend rejection of the JU Proposal. We address some of the individual modifications from the JU proposal below.

Elements of the JU Proposal that Align with Cost Causation and Should Be Adopted

Costs for Facilities at Voltage Levels That Are Higher than the Customer's Point of Connection Should be Entirely Shared

The first element of the proposal that is worthy of independent adoption is that the methodology should treat any cost in a voltage level above the customer's point of connection as entirely shared. The JU's March Workpapers (applying their interpretation of the Staff Methodology) defined a portion of primary and substation costs as local for customers connected at the secondary voltage level. Picture what such a deployment of local assets would look like if a utility were to actually serve a secondary voltage customer as depicted in the JU ACOS studies. The utility would build a portion of a substation devoted to a specific customer's load to transform transmission voltage to primary voltage, build a primary voltage distribution line part of the way to the customer, and then down convert the voltage to secondary voltage at a transformer devoted to that customer before delivering power to the customer. While dedicated primary

[6] These are first ACOS studies filed in response to the May 2019 *Order on Standby and Buyback Service Rate Design and Establishing Optional Demand-Based Rates* and before Staff filed their whitepaper on ACOS methods in December 2020.

voltage lines may be possible for the largest primary voltage customers, it seems highly improbable that any substation or primary voltage equipment would be deployed to serve a specific secondary voltage customer. And were this scenario ever to arise, the costs would be high enough to require excess distribution facility charges and would not be considered part of base rate cost recovery through contract-demand charges.

Adopting this element of the JU Proposal would reflect the real-world design of electric grids. Without this change, secondary customers in particular would be harmed by paying for primary distribution and substation facilities as local costs that were clearly never intended to serve a specific secondary customer. That would add to their contract demand charges, which would assess the costs of these substation and primary facilities on their bills even though their actions may decrease investment needs in these facilities by lowering demand or injecting power coincident with the peak demand of other customers that share those facilities. This part of the proposal is consistent with cost causation principles and is worthy of adoption on its own merit, independent of any of the other elements of the JU Proposal.

The Allocation of Secondary Voltage Costs Between Shared and Local is an Improvement but Does Not Require Sacrificing the Decision Tree

In their March Workpapers, several utilities allocated their entire secondary voltage networks to the local cost category despite the mixed variety of customer-specific and shared facilities employed in secondary voltage systems. In radial systems employed by most utilities, some secondary costs will be customer specific, such as a business served by its own line extension and transformer. However, in other cases, homes and businesses will share distribution infrastructure with other customers up to the point of the meter. In networked secondary systems, such as those widely deployed by Con Edison, the transformers and distribution lines are shared by multiple customers to a much greater extent than radial systems.[7] Some secondary facilities may be installed to serve a specific customer, but it will be less common than in a radial network. In either type of utility system, these secondary facilities are physically mixed between shared and local, and therefore an allocation that reflects cost causation should also be mixed.

In the JU proposal, the utilities have stated that they would answer questions 3 through 5 in the decision tree in a predetermined manner so that all demand-related costs would be subject to the allocator. This change would effectively allocate the secondary voltage costs between shared and local. While the outcome aligns better with the definition of local and shared costs and the design and use of the distribution system, it would be better to retain and improve the decision tree, and the rationale on which it is based, so that it can determine these outcomes instead of obviating the decision tree entirely by basing the outcome

[7] For more explanation on the shared nature of Con Edison's networked secondary distribution systems, please see our March 8 initial comments on the Staff Whitepaper on ACOS Methods at page 5.

on a predetermined path through the decision tree that requires no decisions at all. It would also, in our view, be more consistent with the spirit and goals of this proceeding to improve the methodology based on sound rationale rather than agree to specific outcomes in advance for expedience. In our initial comments on the Staff Whitepaper on ACOS Methods,[8] advanced energy companies recommended modifications to the decision tree that would better account for the impact of individual customer demand on distribution facilities and would result in outcomes that more closely align with the Commission's established definitions for shared and local costs. We still support those recommendations, and we believe they represent a better path for improving and strengthening the decision tree.

Elements of the JU Proposal that are Inconsistent with Cost Causation

The JU Proposal's Allocator is Entirely Unsupported by Any Rationale

In our Reply Comments on the Staff Whitepaper, we explained in detail why allocations that rely on ratios of demand or diversity of demand are only loosely related to the makeup of local and shared costs on a system.[9] For instance, the density and distribution of customers can have significant impact on the makeup of local and shared costs on a system. Customers and businesses that are spaced far apart from each other are likely to need longer lines to serve them, as well as their own line transformers. Apartment dwellers in dense cities may share their transformers with hundreds of neighbors and may have no unique distribution equipment that serves them up to the point of the meter. Density clearly has an impact on the deployment and use of assets in a distribution network, but it would have no impact on the allocation of local and shared costs as determined by a ratio of demand (such as NCP/ICMD, CP/NCP, and ICMD-NCP blend/ICMD). For this reason, advanced energy companies still endorse, as a future approach, an examination of a sample of distribution infrastructure to inform the makeup of shared and local cost allocations over the long-term. An actual examination of the use of distribution infrastructure, and whether infrastructure in the sample serves specific or multiple customers, would ground the local and shared allocations on the real-world design and deployment of the system, including all factors that influence it, such as density, geography, reliability planning, and diversity of demand.

However, we recognize that undertaking such a study at this moment would introduce delays to this already long-running proceeding, and we endorse the staff coincident peak to non-coincident peak ratio as the best practical solution for the near-term. As we explained in our Reply Comments, the Individual Customer Maximum Demand (ICMD) is inappropriate to use as a denominator to describe diversity of demand as no part of the electric grid was designed to accommodate the maximum, non-coincident

[8] See our Initial Comments on the Staff Whitepaper on ACOS Methods, pages 7-10.

[9] Reply Comments of AEEI et al., filed April 12, 2021, pages 2-3.

historical usage of each individual customer as if all such peaks were to occur simultaneously. Rather, the CP/NCP ratio better represents scenarios that the electric system was designed to accommodate.

The JU Proposal Inexplicably Raises Customer Charges from Those Adopted in Rate Cases

In Con Edison's workbooks filed on July 29 providing more detailed calculations of rates for their alternate proposal, customer charges for Service Classes 1 and 2 jumped significantly compared to their March Workpapers. In the March Workpapers, customer charges were $16.50 for SC1 and $28.10 for SC2. In the most recent July filing, customer charges rose to $27.36 for SC1 and $50.72 for SC2. Based on these calculations, we believe that Con Edison in its March Workpapers followed Staff's methodology of maintaining customer charges at existing levels and then adjusting contract demand charges by any difference between customer charge revenues and customer costs (as determined by the ACOS study). However, it appears that in the July filing, Con Edison set its customer charges to fully recover customer costs.

This change in the treatment of customer costs was not identified in the JU narrative explaining the alternative methodology. If it is indeed part of the JU Proposal, advanced energy companies recommend against adopting this change. Customer charges are typically set through negotiation in settlement agreements rather than resulting directly from utility embedded cost of service (ECOS) studies. One of the reasons this occurs is that stakeholders often do not agree with the methodologies used to determine customer costs in ECOS studies. Con Edison allocates significant amounts of demand-related costs (costs that are impacted by changes in customer demand) to the customer cost category based on a "minimum system" argument that a minimum amount of infrastructure needs to exist before customers use any demand at all. Based on this argument, Con Edison allocates nearly 40% of the residential customers' cost share of the utility's sizeable underground networked distribution system to the customer charge.[10] This practice has encountered stiff opposition in rate cases, and due to settlement agreements, has not been fully scrutinized or put into effect. We do not believe that this ACOS proceeding is the appropriate venue to fully adopt the "minimum system" concept in customer charges for the first time. Even when employing the Staff Whitepaper Methodology rather than the modification that is apparent in the JU Proposal, the minimum system concept will result in inflated customer costs, which in turn will be transferred to and result in inflated contract demand charges. We recommend that the Commission adopt the treatment of customer costs in the Staff Whitepaper method and consider investigating the impact of the "minimum system" practice in ECOS studies more generally.

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[10] Calculated using SC1 costs for underground conductors and transformers allocated to customer costs in Con Edison's March workpapers.

Conclusion

We urge the Commission to reject the JU Proposal as an attempt to negotiate rates in a manner that is broadly inconsistent with cost causation. We also recommend that the Commission independently consider two specific elements of the proposal that align with cost causation principles and can reduce some of the disparities between secondary and primary voltage customers that would be likely to result from the JU's interpretation of the Staff Methodology. We have argued the merits of specific elements of the JU Proposal, and in keeping with the initial goal of this proceeding to base standby and buyback rates on principles of cost causation rather than negotiation, we urge the Commission to consider each element of the proposal based on whether it would bring the ACOS methodology in closer alignment with the actual use and design of the distribution system or drive them further apart. We thank the Commission and Staff for their persistence in addressing this crucial rate design issue and appreciate the Commission's consideration of our comments.