August 18, 2023

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

RE: Case 19-E-0283 – Reply Comments on the Staff Whitepaper Regarding Marginal Cost of Service Studies

Dear Secretary Phillips,

Please file the attached reply comments on behalf of the Clean Energy Parties, in the above-referenced proceeding. Please direct any questions on this submission to Noah Ginsburg at noah@nyseia.org or 347-509-6044.

Respectfully submitted,

Noah Ginsburg
Executive Director
New York Solar Energy Industries Association

August 18th, 2023

RE: Case 19-E-0283; Reply Comments Regarding the Staff Whitepaper for Marginal Cost of Service Studies

Dear Secretary Phillips,

On July 20th, the Joint Utilities[1] (JU) and the City of New York filed comments in response to the Staff Whitepaper Regarding Marginal Cost of Service (MCOS) studies submitted on March 27th, 2023 in Case 19-E-0283. The Clean Energy Parties (CEP), a coalition of clean energy trade associations active in New York[2], submit the following reply comments in response to selected items contained in the comments of the JU.

I. Probabilistic Load Forecasts

The Staff Whitepaper (Whitepaper) states:

> "*Given the increased uncertainty regarding load growth, Staff recommends that the Commission confirm its preference that the Joint Utilities rely upon probabilistic demand forecasts for distribution planning. The flexibility to consider the potential for high-cost and low-cost outcomes is known as optionality in capital planning.*" (p. 26)

The JU oppose this recommendation and claim that they perceive it as a mandate for uniformity in the forecasting process that will likely cause each utility to lose some of its ability to reflect unique company and service territory characteristics (JU Comments p. 10-11). The JU seem to be misconstruing the recommendations of the Whitepaper, as the use of probabilistic forecasting methods and reflecting unique company or service territory characteristics are not mutually exclusive. It is not clear how the JU drew this conclusion from the language of the Whitepaper. The recommendations of the Staff Whitepaper

[1] The Joint Utilities define themselves as 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).

[2] The CEP is a group of aligned commenters including the Solar Energy Industries Association, the New York Solar Energy Industries Association, New York Battery Energy Storage Technology Consortium, the Coalition for Community Solar Access, Vote Solar, the Alliance for Clean Energy New York, and Advanced Energy United.

do not preclude variations in probabilistic scenarios among utilities to reflect their unique weather, customer base, and expected rates of electrification adoption.

The JU also claim that:

> "*Moreover, even though forecasting assumptions may appear to be based on a deterministic approach, the reality is that in many cases the deterministic value assigned to an input is based on an assessment of the probability of certain events occurring in the future.*" (JU Comments p. 10)

In this case, the utilities should disclose the scenarios and assumed probabilities that informed the resulting input value. As the Whitepaper elaborated, forecasting electric loads has become increasingly uncertain and probabilistic scenarios can help inform riverbanks to load forecasts in this uncertain future. Scenarios for high and low uptake of electrification of heating and transportation can be assessed in combination with different weather scenarios and post-covid commercial load patterns. These scenarios can help define upper and lower bounds for what is possible and inform the selection of a forecast value that is determined to be most probable based on available information.

The substation deferral scenario described on pages six through nine of the JU comments seemingly contradicts their arguments against use of probabilistic load forecasts since they note that "load growth trends will inherently vary" as will the headroom/deficiency in different scenarios (JU Comments p. 7). Based on these uncertain outcomes, it seems that probabilistic load forecast scenarios could help identify the range of potential deferral outcomes and the range of values among them. A cost-optimized solution will not necessarily be achieved with designs based on a midpoint estimate. If there is a relatively high probability, for example greater than 30%, that the midpoint design would be insufficient and result in much higher total cost to come back and upgrade a second time compared to upsizing initially, then the least-cost solution is likely not to design to the midpoint. Deployment of probabilistic analyses will be increasingly important in a whole range of utility planning activities as electrification accelerates.

Despite the opposition to a requirement to conduct probabilistic load forecasts, Distribution System Implementation Plans (DSIPs) filed by each utility in June 2023 indicate that probabilistic methodologies are already being employed to varying degrees. National Grid currently produces probabilistic electric load forecasts for the Company's entire system as well as distribution feeder-specific forecasts. These forecasts account for base load from weather, load contribution from EV and electric heat, and load reduction from other Distributed Energy Resources (DERs) including solar PV, storage, and energy efficiency.[3,4]

Central Hudson's DSIP outlines the progression of its Integrated System Planning Process from a deterministic peak load forecast to a probabilistic forecasting method.[5] The Company further notes that since the initiation of the DSIP process in 2016, it has evolved its planning process to produce granular, location-specific, probabilistic forecasts and to separately track gross loads from solar, battery storage, building electrification, electric vehicle loads, and incremental energy efficiency.[6] Additionally, Central Hudson has engaged a vendor to deliver a robust probabilistic load forecasting tool that can assess base loads and DERs and has a planned in-service date of December 2023.[7]

NYSEG and RG&E's DSIP describes ongoing efforts with vendors to develop methodologies that forecast DERs by location and reflect probabilistic factors in DERs and load forecasts.[8] Con Edison is currently using probabilistic approaches to assess the growth rate of solar PV installations for time periods beyond the known interconnection queue, and is moving toward a probabilistic approach to assess energy storage.[9] They also report employing probabilistic planning methods as part of their distribution planning to evaluate the need for feeder relief to meet reliability standards.[10] Orange & Rockland is also moving toward a probabilistic approach to assess energy storage; its method incorporates historical growth rates of DER technologies with similar characteristics, such as space requirements, as indicative of energy storage growth patterns.[11] To account for shifts in energy demand, both Con Edison and O&R report using load modifiers to inform load forecasts. The load modifiers, such as energy efficiency, demand response, EVs, solar, battery storage, NWAs, and building electrification account for changes in the total forecasted load.[12,13,14]

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[3] Case No. 16-M-0411, National Grid 2023 DSIP Update, 6/30/2023, p. 26
[4]Id. pp. 32-34
[5] Case No. 16-M-0411, Central Hudson DSIP Update, 6/30/2023, p. 5
[6] Id. p. 7
[7] Id. p. 40
[8] Case No. 16-M-0411, NYSEG and RG&E DSIP Appendices, 6/30/2023, p. A. 1-8, A. 1-10
[9] Case No. 16-M-0411, ConEdison DSIP Update, 6/30/2023, Appendix A, p. A-16 and A-19
[10] Id. p. 21
[11] Case No. 16-M-0411, Orange & Rockland DSIP Update, 6/30/2023, p. 229
[12] Id. p. 17 and pp. 31-32
[13] ConEdison DSIP Update, 6/30/2023, p. 24
[14] Id. Appendix A, p. A-16 and A-19

In summary, the recent DSIPs filed by each of the JU indicate the capability to conduct probabilistic load forecasts in ways that are consistent with their system planning processes. Furthermore, the probabilistic forecasting methods used to estimate load modifiers suggest that the counterfactual forecasting method proposed by the Staff Whitepaper can be accomplished with existing capabilities.

II. Counterfactual Load Forecast

The JU oppose the use of the counterfactual load forecast which excludes future DERs that have not made the initial 25 percent down payment on interconnection costs (JU Comments p. 12). In support of their position opposing the counterfactual load forecast, the JU state:

> "*this approach produces a forecast that implicitly assumes there will be no new DERs beyond those projects which have made the initial down payment. Given the State's energy policies and likely future trends, it is more realistic to rely on the most likely scenario for DER interconnection over the study time horizon.*" (p. 12)

The JU logic is flawed in two important ways. First, the purpose of the analysis is to value the contribution of the assets that will be built. If the utilities assume that the assets are all already built, then the benefit that they provide is already included in the analysis and is therefore not being properly analyzed.

The second flaw is that it presumes that DERs will continue to get built, without regard to the Value of Distributed Energy Resources (VDER) price signals. DER developers are highly sensitive to price signals and the Demand Reduction Value (DRV) is a significant part of the VDER price signal. Since the DRV is fixed for the first ten years of a DER's lifespan, it is a non-volatile part of the VDER compensation. The Environmental component is the other non-volatile price signal among the most common VDER value streams. The energy and capacity values are volatile and as a result are riskier cash flows. The certainty of the DRV payment stream is important to DER developers and is important to driving capital investment.

The CEP contend that the 25% threshold rightly excludes small projects as those projects are compensated via net metering and therefore project viability is based on future retail *rates* not on calculated MCOS values. Conversely larger DERs compensated on VDER are dependent on the DRV derived from MCOS studies. In essence the absence of new DERs would be the default state of affairs but for the sufficiency of the VDER price signal they have instead been constructed.

The exclusion of DERs that have not made the 25% interconnection down payment does not conflict with the overarching recommendation that MCOS estimates be reflective of the costs that the respective utility would be expected to incur and for which they would seek rate recovery. If DER construction were to stop, the utility would have an obligation to serve the incremental load that would otherwise be served by the DER. As a result, it is reasonable to conduct the MCOS studies under the presumption that the DER will not materialize if it is not compensated for the incremental load that it is capable of carrying.

While the 25% interconnection down payment threshold is the most reasonable input to the MCOS studies, it still overstates the DER capacity that is likely to materialize. The interconnection queues of the JU demonstrate that there is still attrition of projects that make the 25% interconnection downpayment. These projects are identified in the "Project Complete" field as being withdrawn (W) or not yet complete (N).[15] Many projects denoted with an N that have been in the interconnection queue for more than three years also have a high likelihood of future withdrawal. The following table demonstrates the number of projects making their 25% downpayment that have withdrawn from the queue.[16,17] As a result, the 25% downpayment threshold still includes a significant amount of phantom capacity that will fail to materialize, but nonetheless it provides the most reasonable and transparent estimate for future DER capacity.

Attrition of Projects that Have Made The 25% Interconnection Downpayment (2017 – Jun 2023)

	Total Capacity Withdrawn by Year of Down Payment [Capacity Withdrawn [MW] (% Total Capacity for Downpayment Yr)]				
Year	**O&R**	**Ngrid**	**ConEd**	**CenHud**	**Total**
2017	28.1 (41%)	35.9 (25%)		39.6 (46%)	103.6 (35%)
2018	15.3 (48%)	12.5 (13%)	6.1 (89%)	15 (32%)	48.8 (27%)
2019	17.8 (73%)	179.3 (35%)	5.7 (83%)	20.8 (54%)	223.6 (39%)
2020	3 (15%)	243.9 (26%)	10.3 (15%)	12 (18%)	269.2 (24%)
2021	12.5 (40%)	131 (17%)	40.6 (42%)	3.2 (16%)	187.2 (20%)
2022	14.9 (24%)	62.7 (9%)	6.8 (21%)	11.3 (16%)	95.7 (11%)
2023		5 (2%)	0.9 (5%)		5.9 (2%)
Total	**91.5 (33%)**	**670.2 (20%)**	**70.4 (30%)**	**101.7 (30%)**	**933.9 (22%)**

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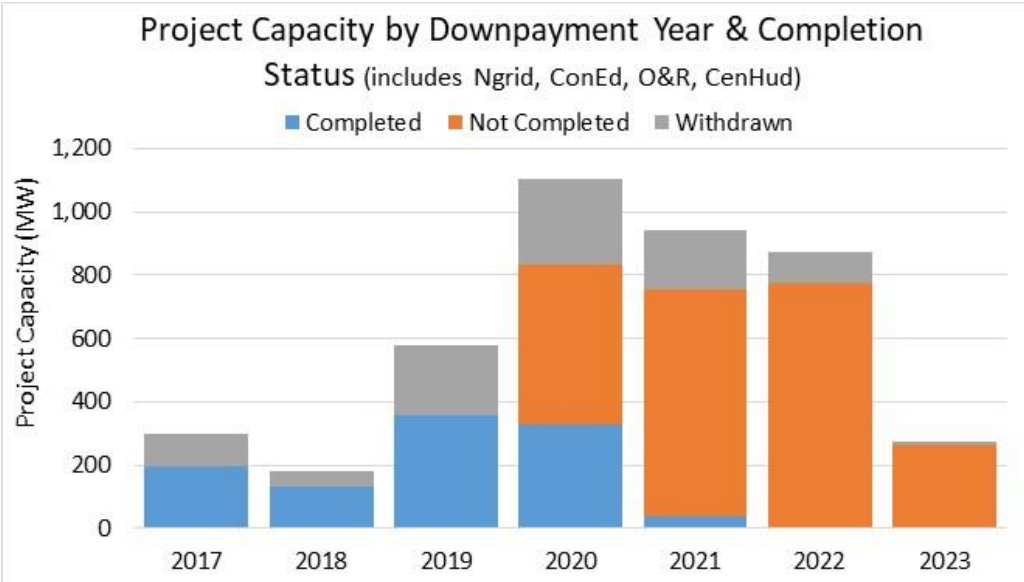
[15] Utility Interconnection Queue Data, Available at https://dps.ny.gov/distributed-generation-information.

[16] This data was obtained from the June 2023 Interconnection Queue spreadsheets for each utility available at https://dps.ny.gov/distributed-generation-information.

[17] The CEP conducted an analysis of the interconnection queue for each utility, identifying the number of projects making the 25% downpayment by year by "Project Complete" status. The values for this field are either "Y" = Project Complete, "N" = Project Still in Development/Construction, or "W" = Withdrawn. Due to data quality issues with the NYSEG and RG&E dataset, the CEP analysts were unable to include it in the analysis.



Despite ambitious state policy goals, there is significant friction to developing clean energy projects in New York. Even distributed-scale projects can run into difficulties with permitting, local opposition, PILOT[18] negotiations, and interconnection upgrades. Rising interest rates are likely to further challenge marginal projects. These difficulties are echoed in a recent report produced by the New York State Comptroller's Office that identifies the risk of a shortfall in renewable generation relative to New York's goals due to challenges related to DER incentives, permitting and siting, and interconnection.[19] As a result, the JU cannot assume that DER capacity will simply continue to materialize due to the State's policy objectives in their MCOS load forecasts. These DERs are reliant on the price signals within VDER, as well as a host of other factors, in order to come to fruition.

III. Reliability vs. Growth Investments

The JU seem to take an extreme interpretation of the Staff Whitepaper as requiring the inclusion of reliability projects in the cost estimate inputs for the MCOS studies. The Whitepaper recommends that multi-value projects with both growth and reliability components be incorporated into the sample of construction projects used to calculate $/kW investment costs for a traditional NERA method MCOS study. (Whitepaper p. 18) The JU do raise a concern regarding the "practical implications in real world situations" to determine the allocations of asset costs to reliability and growth (JU Comments p. 15). The CEP recognize that there are instances where such an allocation is not straightforward or possible, but the CEP

[18] PILOT = Payment in lieu of taxes
[19] Office of the NY State Comptroller Thomas D. Napoli, "Renewable Electricity in New York State: Review and Prospects" August 2023 pp. 7-11

nonetheless reiterate the position from initial comments that the growth related costs for multi-value projects be included in the sample of capital costs used as an input to MCOS Studies. The JU concerns can be addressed through inclusion of projects that meet certain thresholds for the growth component and the practical ability to isolate growth driven components. It is very important that the sample of capital costs for growth driven projects as an input to the MCOS studies be robust and representative. Therefore, the growth components of multi-value projects should be included when possible.

IV. 10 Year Time Horizon

The CEP disagree with the JU assertion that "*the most important years in the study are the first few years because with regular updates of MCOS results, the later years in a study today would be rendered irrelevant by new MCOS results two years from now*" (JU Comments p. 20). This statement reflects short-term thinking and fails to acknowledge the value in longer-term scenario-based forecasting given the rapid changes that are occurring in the electric sector. It also suggests that the utilities see little value in long-term forecasts based on the premise that the out years are subject to change. This uncertainty in the out years does not render the forecasting exercise futile as the utilities suggest, but serves an important purpose to signal where the potential exists for growth driven capital investment in the distribution system. Furthermore, an important purpose of the MCOS is to serve as an input to derive the DRV price signal in VDER. A 10 year time horizon is needed to send a price signal to attract investment where warranted. Large DERs can take several years to develop and the utility proposal to focus on only the near-term years would result in an insufficient and misaligned price signal.

V. Presentation of Costs & DRV and LSRV Calculation Methods

The Staff Whitepaper recommends that marginal cost estimates be made for each substation area on an annual and levelized basis for ten years (p. 43). The intent of this recommendation is to provide the flexibility to group LSRV areas together for compensation purposes. The importance of accurate temporal and locational price signals has been a core principle of REV proceedings and the Staff Whitepaper recommendation is in the spirit of furthering the locational accuracy of DRV and LSRV prices to animate markets for DERs when and where they provide the greatest benefits. The CEP believe that, to date, the DRV has been an effective temporal price signal, driving increased co-location of energy storage with PV to drive peak coincidence of DER exports. However, improvements are needed to LSRV geographic definition, valuation, and administration to make it a more effective price signal to drive DER development in the locations where DERs provide the greatest cost deferral benefits to the system. As explained further in the following section, the CEP have concerns regarding the current administration and effectiveness of the LSRV. The CEP support modifying LSRV capacity allocation to account for the capacity the resource is able to provide during the peak period which drives local distribution capacity needs to more accurately reflect the DER's ability to defer distribution upgrades.

The JU counter-proposal includes bespoke avoided cost studies for LSRV areas and calculation of a systemwide DRV for all other areas of their networks (JU Comments pp. 19-20). This conflicts with the Staff Whitepaper's recommendation to use the iterative process employed by NYSEG & RGE that was conducted by NERA (Whitepaper p. 45). The CEP are cognizant of the concerns raised by the JU regarding the potentially burdensome requirement to group cost information by substation for utilities with large service territories and also the unclear process described in the Staff Whitepaper for grouping like areas together (JU Comments pp. 20-21). At the same time, it is unclear how the JU proposal to conduct detailed avoided cost studies at levels of granularity similar to Non-Wires Solution (NWS) projects is any less burdensome (p. 6). The CEP are also concerned that a utility administered LSRV program design functionally similar to NWS projects would be less scalable and beneficial for NY's decarbonization goals.

The JU also seem to continue to reflect a short-term mindset, stating that "Using deferral value to establish the LSRV credit would provide direct price signals for **near-term needs**, with areas identified on a timeline sufficient to potentially effect such a deferral" (JU Comments p. 9). Staff has rightly identified that the run of the MCOS should be ten years. DERs can take several years to develop and therefore periodic MCOS studies should hopefully be able to identify emerging LSRV areas with sufficient lead time to send price signals to attract DER development.

An objective of VDER is to send a more accurate price signal to DERs and the basis for Staff's proposal to group studies by substation was to improve granularity. There may be other ways to accomplish this such as calculating marginal costs by utility zone or geography. The JU counterproposal for separate avoided cost and MCOS studies departs from the record developed in this proceeding and frustrates the goal of improving the locational granularity of the LSRV price signals. It appears to amount to a "Business as Usual" approach to MCOS studies for the calculation of DRV with an added, but potentially narrow focus on specific LSRV zones that have yet to be defined. The risk in this approach is undervaluing the DRV price signal in non-LSRV areas where DERs can provide benefits to the distribution system and precise valuation of LSRV capacity in places that may be inaccessible to DERs due to geographic limitations.

Based on the record in this proceeding to date, the CEP support the Staff position in the Whitepaper recommending "a continuation of the traditional NERA method with more recent methodological issues corrected as discussed herein…" and estimation of LSRV costs "via an iterative process similar to the procedure used by NYSEG and RG&E" (Whitepaper p. 45). The CEP contend that this method can allow for increased locational granularity in VDER price signals if conducted by specific geographies of utility service areas that may have unique characteristics in comparison with others.

VI. Request for a Technical Conference Focused on LSRV Calculations and Administration

The JU Proposal for calculating LSRV using avoided cost studies akin to what is done for NWS projects is new and introduced well past the development of the record in this proceeding. Given the significant differences between the Staff proposed iterative NERA method and the JU proposal to calculate DRV and LSRV using separate methodologies, a technical conference focused on LSRV calculation methods is warranted. Based on the current state of the proceeding and the divergent proposed methods, the CEP argue that the Commission is not in a position to reconcile these two proposals on the basis of available information.

The CEP also suggest utilizing a technical conference to discuss the experiences of members which indicate that the LSRV is not presently working as intended in practice. CEP members report that DER development in LSRV areas has been hampered by the narrow definition of LSRV eligible geographies; a lack of transparency regarding available LSRV capacity at given locations; and LSRV capacity allocation that fails to accurately account for the capacity a DER will likely provide in the particular peak period for a particular LSRV. The technical conference proposed by the CEP would have an agenda focused on the proposed LSRV calculation methods and a review of current LSRV administration issues that warrant improvement.

VII. Conclusion

The CEP thank the Commission and Staff for their work in this proceeding and are confident that the Commission has a sufficient record available to make a decision on all segments of the Staff Whitepaper, with the exception of issues related to derivation of LSRV. The CEP recommend a technical session to further investigate the competing proposals and also to discuss ways to improve LSRV administration so that DERs can respond to the price signals and provide tangible deferrals in distribution upgrade requirements.