March 16, 2026

RE: Case 15-E-0751; Comments in Response to the Department of Public Service Staff Proposal on Updating DRV and LSRV for VDER Compensation

Dear Secretary Phillips,

On December 11, 2025, the New York Department of Public Service (DPS) filed its *Proposal on Updating DRV and LSRV for VDER Compensation*. In its filing, Staff proposed that each utility's Demand Reduction Value (DRV) be set equal to the average system-wide Marginal Cost of Service (MCOS) of all non-zero cost areas[1] and that the Locational System Relief Value (LSRV) be set using a new statistical methodology to provide meaningful price signals in higher than average cost areas.[2] DPS noticed a date of March 16, 2026 for comments addressing Staff's proposal. The Clean Energy Parties[3] (CEP) respectfully submit the following comments for consideration.

Scope of Comments

In compliance with the Commission's August 19, 2024 *Order Addressing Marginal Cost of Service Studies*, each utility filed an updated MCOS study using the NERA method by June 30, 2025.[4] The CEP anticipated that the 2025 MCOS studies would be more uniform and find significantly higher MCOS values than in years prior due to the Commission directive to include avoided cost of transmission[5] paired with general cost escalation trends over the last five years. While the proposed MCOS values for upstate utilities are generally aligned with the CEP's expectations, Orange & Rockland's (O&R) MCOS decreased significantly, and Consolidated Edison's (ConEd) is much lower than expected.[6] Key factors influencing MCOS results are discussed in the body of these comments. In summary, the CEP submit the following recommendations:

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[1] Case 15-E-0751, Department of Public Staff Proposal on Updating DRV and LSRV for VDER Compensation, December 11, 2025, p. 4

[2] Id., p. 6

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

[4] Case 19-E-0283, Order Addressing Marginal Cost of Service Studies, August 19, 2024, p. 53

[5] Case 19-E-0283, Order Addressing Marginal Cost of Service Studies, August 19, 2024, p. 44

[6] The current DRV is derived from ConEd's 2017 MCOS which was $226; Staff's proposed MCOS using ConEd's Workpapers from July 2025 calculate an MCOS of ~$253.

1. The Commission should set DRV to 100% of MCOS, eliminating “de-averaging” as proposed in the Staff Proposal, and should issue an Order approving new DRV values as soon as possible to enable New York to maximally leverage the Federal Investment Tax Credit (ITC) while it’s still available.
2. The Commission should implement a one-time opt-in that allows developers that recently paid their 25% deposit to elect to receive new DRV rates for this iteration only.
3. The Commission should take a two-track approach, approving the MCOS Studies and updated DRV rates as soon as possible so that projects can proceed with clarity prior to the ITC deadlines, while allowing for further time and process to address details such as the operationalization of Staff’s LSRV proposal.[7]
4. The Commission should direct the utilities to improve and standardize their MCOS methodology, including by:
    a. Requiring input costs to include all known and measurable costs associated with growth related projects, including load transfers, and reflect the most current available cost information.
    b. Clarifying that the utilities are to use their post-tax Weighted Average Cost of Capital (WACC) in MCOS Net Present Value (NPV) and levelization calculations.
    c. Requiring that capacity in multi-year substation and transmission projects be discounted by the post-tax WACC for each year prior to the in-service date.

These recommendations are further discussed below.

1. The Commission Should Urgently Adopt the Staff Proposal to Set DRV to 100% of MCOS

<u>An Order Approving DRV Should be Issued Quickly to Align with ITC Deadlines</u>

The CEP observe that there is already an established record examining methods used to derive DRV and LSRV, and while details surrounding LSRV implementation and operationalization may need to be deferred to sufficiently respond to Staff’s proposal, and the Joint Utilities forthcoming LSRV tariff recommendations and operational requirements, the CEP urge the Commission to move quickly in issuing an order that approves new MCOS/DRV values on a timeline that allows developers to make educated decisions regarding ITC capture.

[7] It is the CEP’s expectation that any modifications to the utilities’ DRV windows be proposed in subsequent MCOS filings for consideration on a biennial cycle so that any such modifications are communicated to market participants with sufficient advanced notice to avoid market disruption. The CEP’s understanding is that any changes to DRV windows are not in scope for the near term process to determine parameters for operationalization.

The urgency is due to upcoming deadlines for ITC eligibility for solar projects. In July 2025, the United States Congress passed H.R.1, sweeping legislation that terminated the clean electricity ITC for the majority of solar projects that do not commence construction by July 4, 2026. This federal policy change is forcing developers to triage their portfolio of prospective solar projects so they can commence construction for their most viable projects with finite development capital and safe harbored equipment. Developers are completing this exercise all across the United States, which means New York is competing with other states to attract clean energy development capital ahead of July 4th, 2026. Many projects under development today that do not commence construction by July 4, 2026 will not secure the Federal ITC, a tax credit worth at least 30% of the total project cost, and they are unlikely to be completed without the ITC. If the Commission were to expeditiously adopt the Staff Proposal for DRV (with minor modifications based upon stakeholder comments), this could enable more New York projects to be economically viable, attracting development capital ahead of the July 4, 2026 deadline and enabling more projects in New York to be constructed with federal support.

The urgency is compounded by the fact that at the present time, the majority of the NYSERDA NY-Sun budget has been allocated. This has the effect of creating a near-term state-level incentive cliff after the remaining capacity is reserved. Quickly adopting updated, more accurate DRV rates will help preserve the viable projects that are sufficiently advanced to qualify for the ITC and support continued development of solar in NY as developers contend with reduced federal and state incentives.

<u>DRV Should be Set to 100% of MCOS as Proposed by Staff</u>

The CEP urge the Commission to approve Staff's proposal to set the DRV to 100% of MCOS. As discussed in prior CEP comment letters, MCOS is an underestimation of the true value of Distributed Energy Resources (DERs) as it ascribes no value to unknown upgrades nor does it account for the significant load growth we expect to see beyond the 10-year study period.[8] Additionally, the Joint Utilities' (JU) decision to use nameplate capacity as an input in MCOS workpapers rather than incremental load further exacerbates this underestimation of MCOS. The CEP believe that Staff's proposal to set DRV to 100% MCOS responds to these issues, is informed by an extensive evidentiary record in this proceeding and is the most accurate, transparent, and administratively efficient way to derive the DRV price signal.

Staff's proposed modifications to the NERA method, such as calculating costs by substation area from the substation downward to the secondary level, provides an accurate view of marginal costs that are less likely to be volatile due to the larger capacity denominators involved. This

[8] Case 19-E-0283, CEP Comments on Parties' Proposals Regarding Process for Calculating LSRV and DRV Values to Inform Pricing, February 26, 2025, pp. 9-10

innovation in the calculation method by Staff reduces the risk of the NERA method providing high MCOS results due to low project sample sizes by voltage level. It should also result in greater year over year stability in updates. As a result, a de-averaging or discount to the calculated MCOS value is no longer justified.

Other methods, such as deaveraging, vary widely among the utilities and rely on assumptions that experience has proven to be faulty. One such assumption is the percentage of the system and capacity value that should be apportioned to LSRV and removed from DRV, under the expectation that LSRV resources will materialize. Other proposed methods, such as percentage discounts to MCOS are lacking in quantitative support or at worst, arbitrary.

The CEP argue that Staff's proposed method to calculate MCOS for VDER is thoughtful, consistent with prior Commission Orders, and is likely to produce a durable cost-based price signal for the distribution value of DERs for many years to come. As a result, the CEP request that the Commission approve Staff's proposed method for MCOS calculation for the purposes of calculating DRV as soon as possible.

<u>Further Support of the Staff Proposal to Eliminate De-averaging of DRV Based on LSRV</u>

The Commission's March 2017 VDER Transition Order adopted the DRV and LSRV as part of the Value Stack and directed each utility to file both an MCOS study and an Implementation Proposal detailing the methodology employed to "de-average" MCOS values to determine: (1) a system-wide DRV, and (2) an additional LSRV applicable to a limited number of MW in select high value areas.[9] In September 2017, the Commission approved the calculation methods outlined in the utilities' implementation proposals.

The calculation methods approved in 2017 were meant to act as placeholders while parties considered a more cogent approach to translating MCOS into DRV and LSRV. In 2018, Staff filed a whitepaper proposing to eliminate LSRV and replace the "de-averaged" DRV with the full system-wide marginal cost estimates used for each utility's energy efficiency cost-benefit calculations.[10] The April 2019 Value Stack Compensation Order rejects this proposal, noting that locational price signals are an important part of VDER and cannot be sufficiently replaced by other existing offerings such as Demand Response (DR) programs or Non-Wires Alternatives (NWAs).[11]

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[9] Case 15-E-0751, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (VDER Transition Order), March 9, 2017, p. 117

[10] Case 15-E-0751, Whitepaper Regarding Future Value Stack Compensation, Including for Avoided Distribution Costs, December 12, 2018, p. 7

[11] Case 15-E-0751, Order Regarding Value Stack Compensation (Value Stack Compensation Order), April 18, 2019, pp. 17-19

In response to concerns over significant decreases in 2018 MCOS values and a lack of consistency in how studies were conducted, the Value Stack Compensation Order directs utilities to continue using the last MCOS studies accepted by the Commission for use in their VDER tariffs and initiates a new proceeding to further examine MCOS studies.[12] In March 2023, Staff filed a whitepaper detailing a proposed framework for updated MCOS studies, and in August 2024, the Commission filed an Order Addressing Marginal Cost of Service Studies directing utilities to file new studies using the NERA method by June 30, 2025.[13]

Staff's most recent proposed method eliminates the "de-averaging" step where the MCOS is adjusted into DRV and LSRV components. Staff's rationale is that since the DRV is applicable everywhere in a utility service area, it should be based on long run system-wide avoidable costs.[14] They further state that de-averaging is no longer appropriate and that LSRV eligibility should be a function of more factors beyond the relative levels of costs in these areas compared to the rest of the system. The CEP strongly support this approach.

<u>Approval of Staff's DRV Proposal Promotes Ratepayer Affordability</u>

Swift approval of Staff's DRV proposal is an important tool to maintaining affordability for NY ratepayers. The ITC effectively buys down the cost of solar resources for New York ratepayers by 30%. Furthermore, the ITC attracts private capital to solar projects and often reduces debt financing costs due to the lower cost basis that must be financed relative to the total project cost. As explained in greater detail later in this document, Staff's proposed method is more likely to result in an underestimation of true marginal costs because it uses the nameplate capacity of utility upgrades instead of actual incremental loads in the denominator for calculation of unit values. Nameplate capacity of upgrades will always be larger than incremental loads.[15] When the DRV price signal is sufficient to attract new DER investment to reduce peak loads, it should do so at a cost below traditional utility infrastructure solutions due to the dynamic mentioned above. The DRV's ability to attract private capital to reduce peak loads is to the benefit of ratepayers and has the effect of reducing the costs of meeting peak demands. DERs don't have a guaranteed rate of return requirement on invested capital and project owners bear the risk of cost overruns and non-performance.

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[12] Id., p. 16
[13] Case 19-E-0283, Order Addressing Marginal Cost of Service Studies, August 19, 2024, p. 53
[14] Id. p. 4
[15] Some utility capital plans call for building multiples of the stated load relief need with the intent of "future proofing" the system. For example, the substation projects included in ConEd's workpapers are forecasted to serve 590 MW of new customer load through 2034, but ConEd's plans to build technical capability that significantly exceeds the load growth need with excess 2034 capacity of 2,413 MW. Capital budget source data can be found in Case 25-E-0072, Exhibit EIOP-7 and Exhibit EIOP-7UPD.

In addition to providing ratepayer savings through transmission & distribution system deferral, the DPS Staff Proposal will lower energy supply charges by catalyzing DER deployment. A growing body of evidence demonstrates that increased DER deployment will lower wholesale electricity rates by increasing energy supply and better aligning supply and demand. A recent analysis by Synapse Energy Economics found that scaling up distributed solar deployment and reaching New York's energy storage deployment goal would deliver an estimated $1 billion in annual utility bill savings for all New Yorkers through wholesale market impacts.[16]

2. The Commission Should Authorize A One-Time DRV Opt-in Option

The CEP also request a one‑time opt‑in allowing developers who have recently paid the 25% deposit to elect the new DRV rates for this iteration only. Specifically, the opt-in should apply to projects that paid their 25% interconnection deposit on or after the MCOS study release deadline of June 30, 2025. This cutoff date aligns with the MCOS study horizon, which models system needs starting in 2025.

Additionally, the current DRV rates have not been updated in eight years, so the new DRV values would better reflect current marginal costs and enable the advancement of projects that are currently in development and otherwise able to capture the ITC. In recent years, solar and energy storage developers have been impacted by import tariffs and other inflationary pressures that are challenging the economic viability of many projects. Developers have reported significant interconnection upgrade cost increases, including cases where the utility will revise cost estimates to be 2-4X the original estimate for equipment, labor and overhead, in many cases after a project has already signed an Interconnection Agreement. If these projects are not completed, future replacement projects will be ~30% more expensive due to the phaseout of the federal ITC. By offering this one-time opt-in provision, the Commission would allow a well-defined set of recent projects to access more accurate compensation and materially protect New York's pipeline of distributed solar and energy storage projects that are under development, ensuring that more ITC-eligible projects are ultimately constructed. Furthermore, a one-time opt-in would promote regulatory fairness by ensuring that resources receive the updated DRV compensation value commensurate with the benefits they provide the system with today.

3. The Commission Should Establish a Separate Procedural Track for LSRV Operationalization and Implementation

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[16] Synapse Energy Economics. Sunlight and Storage into Savings: Evaluating Energy Cost Savings from Distributed Solar and Storage Additions in New York. https://www.synapse-energy.com/new-york-distributed-solar-and-storage-savings. January 2026.

Staff's 2025 VDER proposal suggests that LSRV be set to reflect the "threshold level" at which a utility's costs are significantly higher than its average system-wide cost.[17] To achieve this, Staff proposes a new statistical methodology that aims to capture ~10% of a company's service territory based on a standard deviation multiple determined by values in the MCOS datasets.[18] The CEP support Staff's proposal and note that it allows for ratepayer savings when the substation area MCOS is greater than the calculated LSRV payment rate. The CEP recommend some additional process to ensure the "new LSRV" is operationalized to be effective in steering the market and responding to system needs.

Staff further notes that LSRV resources should also exhibit certain levels of reliability and dispatchability to effectively respond to utility planning needs.[19] A separate procedural track to establish LSRV qualification, operating parameters, and performance standards would allow stakeholders to fully respond to utility LSRV proposals without holding up projects that are currently in development. The CEP request a two-part approach where Staff's proposed DRV calculation method is approved as soon as possible while the tariff and program details of LSRV are worked out among stakeholders in the next few months.

4. The Commission Should Direct the JU to Improve and Standardize Their MCOS Methodology

<u>MCOS Filings Should Include Verifiable Project Costs</u>

Accurate and verifiable input costs are critical for the MCOS study to be an accurate reflection of the costs to serve new load. The CEP and their consultants attempted to match sizing and cost data for large projects for each utility and observed varying degrees of agreement with other public filings. The CEP primarily relied upon capital plans submitted in distribution base rate cases for comparison.[20]

The CEP understand that project sizing and cost information can change between filing dates due to revised project specifications, cost inflation, or changes in time horizons between a base rate case and the 10-year MCOS filing. Nonetheless, the CEP encountered more mismatches than expected or that could be explained by the factors listed above. As a result, the CEP

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[17] Case 15-E-0751, Department of Public Staff Proposal on Updating DRV and LSRV for VDER Compensation, December 11, 2025, p. 6
[18] Id., p. 7
[19] Id., p. 8
[20] The CEP used the filings listed below to validate inputs to utility MCOS studies; some examples of data discrepancies identified by the CEP are included in the appendix.
*National Grid – Case 24-E-0323, Exhibit___(EIOP-6CU), Exhibit___(EIOP-17CU), Exhibit___(EIOP-16)
*NYSEG – Case 25-E-0375, Exhibit_(ECE-04CU), Exhibit_(ECE-2CU), Exhibit_(ECE-12CU)
*RGE – Case 25-E-0379, Exhibit_(ECE-04CU), Exhibit_(ECE-2CU)
*ConEd – Case 25-E-0072, Exhibit_EIOP-1, Exhibit_EIOP-1 UPD, Exhibit_EIOP-7, Exhibit_EIOP-7 UPD

recommend that the Commission require MCOS filings to contain references to project cost disclosures in other DPS proceedings such as base rate cases or others dealing with capital projects for high cost transmission and substation area projects.[21] These disclosures could consist of exhibit numbers from other filings so that the project details could be verified by interested stakeholders. This transparency is important due to the large information asymmetry between the utilities and stakeholders regarding projects and their costs.

The CEP also reiterate that MCOS studies must include all known and measurable projects that are driven by load growth. This should include load transfers from one substation area to another. The MCOS Order observes that "*From a theoretical economic perspective, marginal cost should reflect the most efficient solution, and this should require investment projects that were developed on the most reasonable/efficient/accurate longer-range demand forecasts as possible and costed out using the most efficient input prices as possible.*"[22] In many cases, transferring load from one substation to another is the least-cost solution. Based on a review of the MCOS filings by each utility, it is not clear whether the costs of load transfers from one substation area to another, whether to relieve an overloaded substation or to connect circuits to a new station, are consistently captured. For example, in ConEd's most recent base distribution rate case, they disclose several load transfer projects with costs that would be considered material.[23] These projects appear to be omitted from the MCOS workpapers, despite clearly meeting the criteria for inclusion. The CEP request that the Commission specify that in addition to capital projects, the costs of load transfers at the substation area level that are not de minimis be included in the MCOS project input data.

For the MCOS to result in an accurate DRV pricing signal, input project costs must be complete and include all projects needed to meet load growth, including line transfers, to arrive at a representative price signal that is transparent and verifiable.

<u>A Uniform Approach is Needed Across Utilities</u>

While parties were hopeful that the August 2024 Order would result in more uniform utility MCOS studies, the CEP have identified several differences in the methodology employed by each utility.

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[21] The CEP do not request this level of disclosure for Primary, Secondary, or Transformer level projects due to their shorter planning cycles and the administrative burden that such cross referencing could entail.

[22] August 2024 MCOS Order, footnote 86

[23] 25-E-0072, Jamaica to Idlewild (new) [EIOP-7 UPD, pp. 118-127]; Bensonhurst No. 2 to Gateway (new) [EIOP-7 UPD, pp. 85-96]; Brownsville No. 1 to Glendale [EIOP-7, pp. 27-36]; Ossining West to Millwood West [EIOP-7 UPD, pp. 137-140]; Washington Street to Cedar Street [EIOP-7, pp. 292-297]; Water Street to Nevins Street (new) [EIOP-7, pp. 195-204]; White Plains, Elmsford No. 2 to Grasslands [EIOP-7 UPD, pp. 190-194]; Corona No. 1 to Hillside (new) [EIOP-7 UPD, pp. 41-47]; Greenwood to Industry City (new) [EIOP-7 UPD, pp. 20-27]; Brownsville Nos. 2 to Atlantic (new) [EIOP-7 UPD, pp. 28-48]

Key Divergences in Methodology Across Utilities

	Treatment of Project Capacity in Denominator			WACC Used in Calculations		Segmentation Approach	
	Full MW in Year One	Discounted Using WACC	Discounted Using Inflation	Pre-Tax WACC	Post-Tax WACC	MCOS at Each Segment is Additive	No Segmentation
ConEd	x			x		x	
O&R	x			x		x	
NYSEG		x			x	x	
RG&E		x			x	x	
NIMO			x		x		x
Central Hudson		x			x	x	

The table above provides an overview of key differences in the JU's MCOS methodologies. While the DPS Staff Proposal creates more consistency, these different methodological choices made by the utilities flow through and impact the resultant MCOS calculations. The CEP recommend that Project Capacity in the Denominator be discounted using WACC, that Post-Tax WACC be used in NPV and levelization calculations, and that National Grid adopt the same segmentation approach as the rest of the JU.

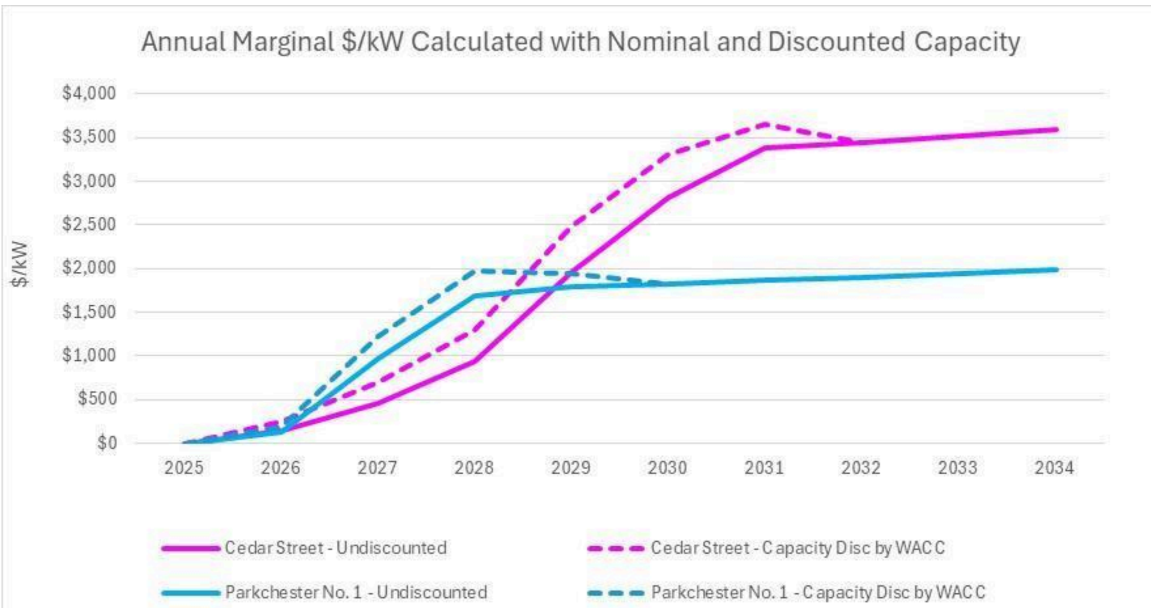
<u>Capacity in Multi-Year Projects Should be Discounted by the Post-Tax WACC for Each Year Prior to the In-Service Date</u>

Many utilities' MCOS filings contain multi-year projects at the substation area or transmission level where spending is spread out over many years and where project capacity may enter service in phases. In the case of ConEd and O&R, the unitized marginal costs of these projects are calculated during each year of construction based on the final project kW capacity at completion with no adjustments. In other words, ConEd and O&R's MCOS calculations assume that 100% of the incremental capacity from multiyear projects is available right when the construction *starts*, rather than when the project is *finished*. This results in artificially low MCOS values in the early years of a project since the denominator is the anticipated final project kW, whereas the cost / economic carrying charge is calculated based upon the portion of project costs incurred to date. Using the final project capacity in each year of the unitization calculation that the economic carrying charge rate is applied to has the effect of depressing the calculated levelized marginal costs.

Many large projects enter service in phases, but it is unrealistic to expect utilities to model bespoke project capacity in-service dates as part of their MCOS studies. At the same time, holding the project capacity static over the life of a multi-year project unreasonably depresses the calculated marginal cost unit rates to which the economic carrying costs are applied.

New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RG&E) addressed this issue in their MCOS studies by discounting the project capacity by the after-tax WACC for each year prior to a project's in-service date. The PSC has previously accepted this method of using levelized calculations to spread the costs across capacity as it is expected to be used.[24]

These differences in the calculated annual marginal cost unit rates using WACC discounted and undiscounted project capacity are illustrated in the graphic below for selected ConEd substation area projects.



Levelized 10-year Marginal Costs by Capacity Denominator Option		
	Project Nameplate kW	**Project kW Discounted by WACC prior to In-Service Year**
Parkchester No. 1	$153.85	$164.34
Cedar St.	$208.44	$233.38

As the table demonstrates, the increase in levelized marginal costs from using capacity discounted by WACC is rather modest but varies proportionally with the duration of the project before it enters service and helps reduce the depression in unit rates that result from using the final project nameplate.

The CEP urge the Commission to require that capacity in multi-year substation and transmission projects be discounted by the after-tax WACC for each year prior to the in-service date. Doing so would alleviate the depression in marginal unit rates in the early years of multi-year projects

[24] Case 89-C-198, Incremental Loop Cost Study Manual, March 1993, p. 5

that results when the full project nameplate capacity is used. It would also more accurately reflect the accumulating costs to ratepayers as these projects progress. This change is especially needed in light of the decision to utilize project capacity instead of incremental load in the denominator for unit rate calculations.

<u>MCOS Calculations That Use Capacity in the Denominator Will Always Yield Lower Results per Unit Than Incremental Units of Load</u>

The record in this proceeding has repeatedly cited the Commission's precedent-setting proceeding from 1976 that consisted of an investigation into marginal cost based pricing. Then, as now, the Commission was grappling with the issue of sending efficient price signals during a period of rapid escalation in system operating costs. In the summary of arguments in favor of marginal costs, the Commission's Order observed that:

> "[f]airness is more nearly achieved, they claim, because customers are charged according to the costs they impose upon the system and therefore, on ratepayers at large by their additional consumption, or the costs they save the system when they practice conservation according to the time of use. It is only fair, they assert, to see that consumers receive a reward for such restraint as they exercise equal to the cost it enables society to save: the measure of that saving is marginal, not embedded costs."[25]

This current proceeding is simply an extension of the Commission's cogent analysis of marginal costs from fifty years ago. In today's application, compensation for DERs is akin to the costs consumers save by practicing conservation according to the time of use. Throughout this Order, the Commission defines marginal costs as being an incremental unit of load or conservation.[26]

Staff's 2023 Whitepaper goes on to explain that:

> "marginal or incremental cost has been defined as the change in a firm's total cost resulting from a business decision to: a) respond to a change in demand; or b) replace an existing facility in order to remain in business (e.g., rehabilitation). All expenditures that change as a result of these decisions are included in the marginal or incremental analysis."[27]

[25] NYPSC Opinion 76-15, Case 26806 - Proceeding on motion of the Commission as to rate design for electric corporations. Opinion and Order Determining Relevance of Marginal Costs to Electric Rate Structures, Issued: August 10, 1976, p. 9.
[26] Id, pp. 8-9, 11, 17-18
[27] Case 19-E-0283, Whitepaper Regarding Marginal Cost of Service Studies, March 27, 2023, p. 8

This interpretation of marginal cost is consistent with the definition provided in the Incremental Loop Cost Study Manual from March 1993, which Staff regularly refers to.[28] This manual further discusses the idea of long-run incremental cost as a way to account for lumpy investments by spreading costs over the full increment of the demand to generate a levelized capacity cost that is often stated on a "per unit of demand" basis and spreads the costs across capacity as it is expected to be used.[29] The current proceeding aligns with this notion, as the understanding has been that marginal costs are based on the cost to serve an incremental unit of demand.[30] [31]

The JU MCOS Studies and Staff's proposal calculate MCOS based on incremental units of capacity additions, not incremental units of load. The CEP recognize that the kW of capacity additions are more straightforward to measure and are a more transparent reference point than potentially uncertain or subjective load forecasts. Nonetheless, use of added kW capacity in the denominator of a marginal cost calculation diverges from a true marginal cost which would use incremental units of demand in the denominator. This divergence between calculated costs using capacity added vs incremental units of load increases significantly when the capacity additions are multiples greater than units of added load. While there are many reasons that a utility may size an expansion with a large amount of capacity headroom, it leads to the perverse outcome where oversized expansion projects relative to load drive down the calculated marginal cost. This in turn distorts the price signal for DERs and rewards a utility through added ratebased costs instead of reliance upon DERs to meet some of the incremental load.

The result of using nameplate capacity as an input is that added capacity will always be greater than incremental load and therefore result in a lower calculated MCOS value. At minimum, using nameplate capacity instead of incremental load to calculate MCOS is a strong justification for the Commission to adopt the Staff recommendation to set the DRV equal to 100% of the MCOS value. As described earlier in this document, the MCOS should not be deaveraged or reduced by any value to derive the DRV because its calculation already undercounts the unit cost of the incremental demand as a starting point. The CEP also stress the importance of having input costs that include all known and measurable items associated with growth related projects and reflect the most current available cost information. If outdated cost information or if growth related projects were to be omitted, it would compound the underestimation of marginal costs that are inherent in the proposed method.

[28] Case 89-C-198, Incremental Loop Cost Study Manual, March 1993, p. 4
[29] Id., pp. 4-5
[30] Case 19-E-0283, Whitepaper Regarding Marginal Cost of Service Studies, March 27, 2023, p. 1
[31] Case 19-E-0283, Order Addressing Marginal Cost of Service Studies, August 19, 2024, p. 2

Structural Changes from the NERA Methodology Must be Enacted

As previously discussed herein, the CEP observe that Staff's proposal involves a new method whereby MCOS is calculated based on all substation areas that exhibit a non-zero marginal cost at one or more segment levels within them. As a result, the MCOS for each substation area is calculated vertically based on the non-zero marginal costs of voltage level segments within it, and the system-wide MCOS is based on the capacity addition weighted average of the substation areas with non-zero marginal costs.[32] This approach is different from the traditional NERA method that calculates non-zero marginal costs horizontally by segment and then sums them to find the total system MCOS. Staff argues that their proposed method is more accurate because "very few, if any, substation areas are affected by proposed relief projects across all network segments" and that "aggregating the segment costs actually faced by each substation produces a more reasonable longer run cost estimate to use as a price signal."[33]

For the Commission to approve Staff's proposed method, it must endorse two structural changes to the MCOS calculation methodology. The first is finding that the vertical calculation method by substation area conforms with the intent of prior Commission Orders on MCOS calculation. The CEP proffer that to approve this method, the Commission would need to affirm that the definition of a "non-zero cost area" consists of a substation area that has a positive marginal cost within the 10-year study period at the transmission, substation, primary, transformer, or secondary voltage level. The Commission would also need to affirm that this method is aligned with the August 2024 MCOS Order that requires calculation of "long-run, non-zero marginal costs regardless of whether segments of a utility's distribution system have no avoidable costs due to near term expected changes in demand."[34] The CEP support Staff's approach, which is aligned with the Commission Order in that the change in the order of operations for calculation expands the vertical reach of the aperture of measurement, but does not factor in substation areas with zero marginal costs.

5. Additional Items for Consideration

Dynamic Load Management (DLM) Rates Should be Updated to Reflect Updated MCOS Values

While it is not directly in scope for the instant proceeding, the Commission must address the fact that VDER and DLM (including the Commercial System Relief, Distribution Load Relief, Term- and Auto-DLM) are closely related. The rigorous and collaborative work completed by Staff, the JU, and industry stakeholders under the MCOS and VDER proceedings will result in more accurate MCOS values that have multiple valuable uses. The CEP urge the Commission to ensure

[32] Id., p. 5
[33] Id.
[34] Case 19-E-0283, Order Addressing Marginal Cost of Service Studies, August 19, 2024, p. 16

that compensation levels for DLM and other programs be updated to leverage the most accurate MCOS values available.

By updating DLM compensation levels, the Commission will enable optimal levels of participation in DLM programs, supporting direct and systemwide ratepayer savings. Accordingly, we recommend the Commission direct Staff to propose a process for immediately updating DLM rates based on updated MCOS values.

<u>Update the Environmental (E) Value to Align with Current Tier 1 Renewable Energy Credit (REC) Prices</u>

In addition to updating the DRV and LSRV, as directly addressed in the Staff Proposal, the CEP encourage the Commission to initiate a parallel track within the VDER proceeding to consider updating the E Value, which has also grown out of date.

In 2017, the PSC established that the VDER Value Stack would include an Environmental Value "based on the higher of the latest [Clean Energy Standard] CES Tier 1 Renewable Energy Certificate (REC) procurement price published by NYSERDA or the Social Cost of Carbon (SCC)."[35] In 2022, the PSC issued an Order expanding the NYSERDA NY-Sun incentive program, and administratively setting the E Value at $0.03103 per kilowatt hour, which "reflects the social cost of carbon (SCC) at a 3% discount rate…"[36] In its 2022 Order expanding NY-Sun, the Commission notes that in its 10 GW Distributed Solar Roadmap, NYSERDA outlined multiple strategies for supporting distributed solar deployment, including a tariff-based "E Value only" approach or alternatively an "expanded NY-Sun MW Block program with the E Value maintained at or near its current level."[37] The Commission opted for the latter approach, and noted that modifications to the E Value could be considered during the NY-Sun Program Mid-Point Review. In its June 2023 Mid-Point Review Order, the PSC declined to update the E Value, noting that the "current incentive structure of the NY-Sun program (i.e., providing upfront incentives) continues to provide for a transparent, efficient and cost-effective path forward to spur additional solar development in New York…"[38] and recommended that future changes to or improvements on Value Stack compensation be addressed in the Commission's larger VDER proceeding.[39]

To implement this recommendation, the CEP recommend that DPS complete a pricing analysis for recent Tier 1 REC solicitations and then file a Staff Proposal for updating the E Value to

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[35] Case 15-E-0751. Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters. March 9, 2017.
[36] Case 21-E-0629. Order Expanding NY-Sun Program. April 14, 2022.
[37] Id.
[38] Case 21-E-0629. Order Adopting NY-Sun Mid-Program Modifications. June 23, 2023.
[39] Id.

provide greater parity among large-scale renewables and DERs, which would then be subject to stakeholder comment and consideration by the Commission.

It is the right time for the Commission to consider updating the E Value to align with recent Tier 1 REC prices, which are understood to be materially higher than $0.03103/kWh. As discussed above, NY is facing an incentive cliff due to the expiration of the ITC and the impending exhaustion of the NY-Sun budget, and the E-Value is another component in the VDER value stack that may need an update.

CEP Response to Staff's Questions for Comment

1. *Is a two-year cadence for LSRV long enough for developers to plan and get to the 25% interconnection downpayment stage of a project? Should the LSRV remain in effect one or two additional years if costs in an area change with the next MCOS filing?*

The CEP recommend that utilities identify new LSRV zones every two years in their MCOS filings, and that utilities quantify the MW of capacity needed in each LSRV zone so this information can be made publicly available through Hosting Capacity Maps. As LSRV capacity is reserved, the public-facing maps should be updated to reflect the reduced LSRV capacity available until the capacity is fully subscribed and no additional LSRV capacity is available. In an instance where the LSRV capacity is not fully subscribed within the two year MCOS cycle, the utilities should simply indicate whether they still have a capacity need and whether it is possible to meet such a need with DER. In some instances, this could result in a utility removing LSRV capacity in their biennial update where they identify new LSRV zones. While this could be disruptive to the development cycle, it's important that the LSRV price signal achieves deferral of traditional distribution upgrades. The Commission can ensure that this process is transparent by directing the utilities to indicate whether they intend to eliminate any current LSRV zones in their MCOS filings so this possibility can be understood by developers before they go into effect.

In addition to LSRV, it's important for the Commission to consider the cadence of DRV modifications. In general, the CEP agree with DPS Staff that a two-year cycle for updating DRV values is reasonable. This aligns with the 2019 Commission decision in the VDER proceeding which found that "the DRV and LSRV shall be determined every three years,"[40] and will provide stability for DER developers while also giving the utilities a chance to implement the standardized MCOS study method prescribed by the Commission and the Staff white paper without any market disruption. The CEP also request that any modifications to the utilities' DRV windows be proposed in MCOS filings for consideration on a biennial cycle so any such

[40] Case 21-E-0751. Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters. March 9, 2017.

modifications are communicated to market participants with sufficient advanced notice to avoid market disruption.

2. *How should results of the new LSRV and DRV be tracked so that in 5 to 10 years the success of this proposal can be best evaluated?*

The CEP recommend tracking resource deployment over time to evaluate the impact of new DRV and LSRV rates. Specifically, resource deployment should be tracked by installs to better understand geographic distribution, market penetration, and program participation rates. While capacity-based tracking provides valuable insights relating to overall grid impact, it can be skewed by a few very large projects that don't necessarily reflect widespread program success.

Additionally, the CEP request that solar and energy storage performance, particularly load reduction within DRV windows and the peak hour, be measured. This real-world data around the value these assets are providing to the grid would make for more meaningful analysis of DRV and LSRV.

3. *How will this proposal affect other planning processes such as (CGPP, PPP, etc.)?*

Adjustments to DRV and LSRV price signals can impact planning assumptions in other cases as changes to the economic attractiveness of DER deployments can directly affect how much DER capacity planners should expect on the system. For instance, the Coordinated Grid Planning Process (CGPP) assesses long-term upgrades to transmission and distribution systems over a 20-year horizon, and new DRV and LSRV rates can alter the projected contribution of DERs resulting in changes to CGPP modeling scenarios. DRV and LSRV rates also influence where projects get built, meaning updated values can shift hosting capacity projections, ultimately impacting proactive planning processes.

4. *What is the most reasonable way of allocating MW for a system-wide transmission project to the underlying substations when calculating a weighted average marginal cost per substation?*

If a transmission project can be identified as benefiting specific substation areas or a region of the utility's transmission system, then the capacity should be allocated pro-rata to those substation areas. If this cannot be done, then the MCOS for transmission projects shall be calculated in total and added to the substation MCOS calculated using Staff's proposed methodology.

5. *What specific language on non-price terms and conditions should be enumerated for LSRV eligibility?*

The CEP support DPS Staff's efforts to update LSRV compensation and recommend that non-price eligibility requirements be clearly defined to ensure consistent program implementation and project financeability. Explicit clarity in a single "LSRV Participation Framework" would be particularly helpful in the following areas:

- Performance requirements, including availability expectations during the LSRV window, duration capability, measurement and verification methodology, and treatment of maintenance and force-majeure conditions
- Operational expectations, including state of charge (SOC) readiness entering the LSRV window, charging flexibility outside the window, and metering and telemetry requirements
- Program coordination, including interaction with DRV and ICAP participation, treatment of utility outages or distribution constraints, and confirmation that LSRV operates as a scheduled seasonal performance obligation rather than an event-based dispatch program

Clarifying these non-price terms will reduce implementation uncertainty and help ensure that LSRV resources can reliably deliver distribution-level system benefits. The CEP will provide further commentary on this subject in reply comments in response to the JU proposal for LSRV.

6. *Should the kW for each year used in Con Edison's and O&R's ten year levelized $/kW-yr avoided cost calculations be discounted so as to produce a levelized cost which represents the net present value of the revenue requirement of the traditional solution investments divided by the net present value of demand that drove those investments? See footnote 82 on page 33 of the August 2024 MCOS Order which notes that in leveling unit cost, dividing the present value of the investment by the present value of the demand would spread costs across capacity as it is expected to be used.*

Yes, the CEP maintain that the true MCOS should be calculated based on incremental demand rather than the amount of capacity created by distribution upgrades. However, we understand that it is complex to complete this calculation and load forecasts are less defined than the capacity created by upgrades. For the purpose of the current cycle we are comfortable with the approach in the Staff Proposal. The CEP encourage Staff to explore how to improve the accuracy of MCOS in future cycles by basing it on incremental demand rather than oversized capacity additions.

7. *National Grid included transmission projects in their MCOS study. Page 44 of the August 2025 MCOS order requires the Commission's directive that the costs of all growth-related transmission projects, including FERC regulated transmission projects should be estimated in the study to best inform the Value Stack. However, National Grid did not designate which transmission projects were bulk federal tariff related which were local NYPSC tariff related. Therefore, Staff could not split the federal tariff related component out of the 10-yr levelized MCOS figures that staff used to determine its proposed DRV and LSRV levels. Thus, the National Grid costs should be viewed as over-statements of NYPSC jurisdictional costs, but not of the totality of long run avoidable costs. How should this issue be handled in any possible revisions of the National Grid and other Joint Utilities MCOS studies?*

For the purpose of calculating an accurate MCOS for VDER rate design, it is not necessary to distinguish between FERC v NYPSC jurisdictional transmission costs, and it is far more important to ensure that the totality of long run avoidable costs is accurate.

Appendix A

MCOS Workpaper Change Log

This Appendix details the changes to the Staff Excel spreadsheet workpapers released with the Staff proposal and revised on March 5, 2026. The CEP have made modifications to the following tabs, which are indicated with green highlights: CECONY; O&R, National Grid; Nat Grid TransMet. The CEP did not alter the “Aggregated Table” tab. Below is a list, by utility of the changes made to the Staff workpapers and the resulting changes to the calculated MCOS values.

ConEd

1) Fix naming issues that cause items to be missed by lookup formulas in columns AS and AB in the Substation section

   a. Change instances of "Parkchester #1" to "Parkchester No. 1"

   b. Change instances of "Parkchester #2" to "Parkchester No. 2"

   c. Change "Fox Hills" to "Fox Hills 33 kV"

   d. Change "Gateway" to "Gateway Park"

2) Adjust WACC to pre-tax WACC, this has to be done in the original ConEd sheet and it slightly changes the carrying charge loaders which have been updated in CEP’s sheet to reflect the change to the Pre-Tax WACC

   a. WACC changed in cell CO3 to 6.845%

3) Discount project capacity for multi-year projects in Levelization calculation

   a. The calculation for discounting capacity runs from P283 thru Z426

   b. All of the intermediate steps have been laid out to show the calculation methods

   c. The formulas in cells BQ214:CA353 were modified to reflect the discounted capacity in the denominator of the calculation

4) Growth related load transfer projects, from one substation to another were added to align w/ CEP's recommendation that these projects should be included.

a. Sources for ConEd load transfer projects include the following exhibits from 25-E-0072: Electric Infrastructure and Operations Panel (EIOP); System Expansion & New Business Capital Expenditures (CapEx) EIOP-7 Updated (UPD): 4/10/2025; EIOP-7: 1/31/2025

b. The page numbers for sources are cited in the new data sections for load transfers, denoted w/ an orange header

c. Project data for load transfers has been added in cells A267:N276. The discounted capacity for these projects and in-service dates are calculated in the sections below this.

d. The costs for load transfer projects are added into the Substation Area cost summation cells in BQ214:CA283.

The resulting changes in the calculated MCOS values for ConEd based on CEP's adjustments to the workpapers are shown in the table below.

Calculation Method	Calculated MCOS ($/kW)
Original Staff Calculation:	$252.54
Calculation after correcting names	$264.20
Change WACC to pre-Tax & Modify Carrying Charge Loaders:	$269.64
Discount Capacity by WACC for Multi-Year Trans and Substation Area Projects	$293.11
Include Load Transfers disclosed by ConEd as growth related costs:	$379.63
MCOS w/ CEP Recommended Changes	$379.63

O&R

1) The CEP added multiple helper tables beginning in column A at row 186 to help calculate the capacity discounted by WACC for large multi-year substation and transmission projects in the years before they enter service.

2) Change WACC to pre-tax WACC of 7.248% in cell M121

3) Discount capacity on multi-year Substation and Transmission projects in helper tables

    a. The first step was to obtain cumulative, unescalated project costs

    b. Next, in the helper tables walk through discounting of project capacity prior to in-service year

    c. After that, calculate inflation escalated costs

4) Divide inflation escalated costs by discounted capacity, convert to kW, and multiply by carrying charge loader

5) In cells B124:K182, adjust the first two formula factors to lookup substation and transmission carrying costs to cells C278:L281 and C:284:L286, respectively

    a. Note that the substation carrying charge loader is lower than the others due to the way its calculated on tab "Demand Related Exp as % of Reproduction Costs" in the O&R MCOS Study

The resulting changes in the calculated MCOS based on CEP's changes above are summarized in the following table.

Calculation Method	Calculated MCOS ($/kW)
Original Staff Calculation:	$22.73
Switch to Pre-Tax WACC:	$23.08
Discount Capacity on Multi-Yr Substation & Transmission Projects:	$24.34

National Grid

On the “Nat Grid Transmnet” tab, the CEP made the following adjustments:

1) A series of intermediate tables were added beginning in Column A, rows 121-320

2) T_Line and T_Station project capacities, discounted by years prior to the inservice date were calculated in the tables in A324:P407

3) The total discounted capacity, by transmission segment, was summed by year in rows 359 and 407

4) The calculations for the unit rates of capacity in cells AV5:BE5 were modified to have the denominator come from row 359

5) The calculations for the unit rates of capacity in cells AV53:BE53 were modified to have the denominator come from row 407

6) The revised denominators replaced the static project capacity values in Staffs sheet that came from $AQ5:$AQ36 and $AQ67:$AQ117, for T_Lines and T_Stations, respectively

This results in an increase in the calculated MCOS for transmission from $65.82/kW to $74.21/kW.

On the “National Grid” tab, the CEP made the following changes:

1) CEP set a materiality threshold for distribution stations, in cell BF1, consistent with its comments to capture large, multi-year distribution substation projects.

    a. This threshold was set for illustrative purposes and does not represent a policy position by CEP for what level should be considered “material” or “significant.”

2) CEP then inserted three columns beginning at column BE to make space for the following:

    a. A TRUE/FALSE flag in column BF to capture projects in excess of the materiality threshold

    b. A date of project completion in column BG

3) CEP added a lookup table to determine the discounting by WACC of capacity for large multi-year projects. This lookup table is located at BH248:BS259

4) CEP modified the formulas in BI6:BR243 to use the discounted capacity in the denominator for projects that meet the materiality threshold

NYSEG

No changes made to Staff's model

RGE

No changes made to Staff's model

Central Hudson

The CEP did not make changes to Staff's model, largely due to difficulty in obtaining workable capacity data regarding the material Central Hudson substation projects including: Northwest 115/70 Woodstock; Pleasant valley 73 pulvers 13kv; and WM Line Maybrook. The CEP urge the Commission to require Central Hudson's study submitted in compliance to any forthcoming order to discount capacity for significant multi-year projects by WACC and provide workpapers that stakeholders can easily follow.

Appendix B

MCOS Input Validation Table

The purpose of this table is to show the difficulty in matching inputs for large projects included in the MCOS studies to information available in recent rate cases. For some projects, we were able to find detailed project descriptions in capital plans, but in general total cost numbers don't match nor do project in-service dates (ISD). Some differences may be attributable to differences in the time horizon between the MCOS and base rate case, but that does not explain all mismatches. We were unable to locate project sizes or MW capacity increases in the NYSEG and RG&E rate case materials.

Utility	Project Identifier	MCOS ISD	Exhibit ISD	Rate Case	Exhibit	Exhibit Project Cost	Cost Difference Between Exhibit and MCOS Study	Notes
RG&E	PRJ-006668	2034 / 2035	H2 2029	25-E-0379	Exhibit_(ECE-2CU), p. 12 of 26 / Exhibit_(ECE-04CU), p. 693 of 1568	$767,363	-$138,029	All Penfield CAS projects are grouped according to RGE CAS Penfield project in the Exhibit; Exhibit costs occur prior to 2031, MCOSS only shows costs 2031 or after; In-service dates shown in Exhibit differ from MCOSS in-service date
RG&E	PRJ-001246	Multiple ranging from 2029-2035	H2 2028	25-E-0379	Exhibit_(ECE-2CU), p. 12 of 26 / Exhibit_(ECE-04CU), p. 682 of 1568	$573,043	$188,189	All CAS Greece projects are grouped according to RGE CAS Greece project in the Exhibit; Exhibit costs occur prior to 2031, MCOSS includes cost that continue past 2031; In-service dates shown in Exhibit differ from MCOSS in-service date
RG&E	PRJ-006665	Multiple ranging from 2030-2035	H2 2028	25-E-0379	Exhibit_(ECE-04CU), p. 686 of 1568	$739,725	$102,592	All projects are grouped according to the RGE CAS Downtown project detailed in the in the Exhibit; Most of the costs shown in the MCOSS occur after 2031; In-service date shown in Exhibit differ from MCOSS in-service dates
NYSEG	PRJ-006661	2033 / 2034	H2 2030	25-E-0375	Exhibit_(ECE-04CU), pp. 328-330 of 1568	$226,810	$102,385	Projects for Scipio, Genoa, and Aurora are grouped together according to Exhibit
NYSEG	Border City	2035		25-E-0375	Exhibit_(ECE-2CU), p. 18 of 26	$135,715	-$105,218	Costs in Exhibit occur between 2025 and 2031 but MCOSS shows costs starting in 2034
NIMO	C060220	2030	2027	24-E-0322	Exhibit__(EIOP-6CU), pp. 37-39 / Exhibit__(EIOP-17CU), NG-562 p. 17	$50,510	$24,621	MCOS workpapers include a final project system capacity of 800 MW, while exhibits show a capacity increase of 43 MW and a project size of 159 MW
NIMO	C081458		2027	25-E-0322	Exhibit__(EIOP-6CU), pp. 34-36 / Exhibit__(EIOP-17CU), NG-564 p. 18	$46,753	-$15,068	MCOS workpapers include a final project system capacity of 550 MW, while exhibits show a capacity increase of 254 MW and a project size of 322 MW