STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of the Value of Distributed Energy Resources	)))	Case 15-E-0751
Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies	)))	Case 19-E-0283

JOINT UTILITIES' REPLY COMMENTS TO INITIAL COMMENTS ON DPS STAFF PROPOSAL ON UPDATING DRV AND LSRV FOR VDER COMPENSATION

I. Introduction

The Joint Utilities[1] submit these reply comments in response to the initial comments submitted by the Clean Energy Parties,[2] NineDot Energy (NineDot), the City of New York (the City), the New York Power Authority (NYPA) and collectively, Carson Power, New Leaf Energy, and Sol Source Power (Other Developers), in response to the New York State Department of Public Service Staff's (Staff) proposed updates to the Demand Reduction Value (DRV) and Locational System Relief Value (LSRV) components of the Value of Distributed Energy Resources (VDER) Value Stack (Staff Proposal).[3]

The Joint Utilities recognize the diverse value distributed energy resources (DERs) can provide to the energy system. Buildout of clean energy across the state is essential to meet the state's Climate Leadership and Community Protection Act (CLCPA) goals, of which solar and energy storage are indispensable components. In particular, when properly deployed at the right time and in the right locations, energy storage can provide grid reliability to meet customer load,

[1] The Joint Utilities are 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 Clean Energy Parties are comprised of New York Solar Energy Industries Association, Solar Energy Industries Association, New York Battery Energy Storage Technology Consortium (NY-BEST), Coalition for Community Solar Access, The Alliance for Clean Energy New York, and Advanced Energy United.
[3] Cases 15-E-0751 et al., *In the Matter of the Value of Distributed Energy Resources* (VDER Proceeding), Department of Public Service Staff Proposal on Updating DRV and LSRV for VDER Compensation (filed December 11, 2025) (Staff Proposal).

as demonstrated in numerous Joint Utilities' non-wires alternatives (NWA) projects. Energy storage is also currently being evaluated as part of a portfolio of solutions to support the recently identified transmission security needs in the New York City area. In order to enable DERs to deliver the greatest value to customers at the lowest cost, DER compensation should be tied to measurable system benefits, taking customer affordability impacts into account. Operational requirements for DER compensation should be tailored to the specific context, including the DER use, whether the need is on the distribution or transmission system, and when the DER enters the market. The Joint Utilities' response to the initial comments of other parties is premised on two key issues laid out in their initial March 16, 2026 comments.[4]

First, the analysis included in the Joint Utilities' Initial Comments demonstrates that the impact of increased DRV and LSRV rates on non-participating customer bills will be significant when DER deployment reaches policy targets.[5] The cost impacts are already evident in the Con Edison service area where there are billions of dollars of DRV payments committed to energy storage projects, with double the 2030 target for distribution-connected energy storage capacity either operating or under contract today.

Second, as explained in the Joint Utilities' Initial Comments, while the Value Stack has been effective in supporting clean energy investment, it has also resulted in overcompensation in areas where DER injections do not result in distribution peak reductions that potentially offset utility costs. The basis for compensating DERs through the Value Stack should evolve to reflect the potential avoided costs that DERs provide to the electric system.

Some of the commenters recognized the operational limitations of the current DRV and LSRV framework. However, these same commenters propose solutions focused primarily on further increasing DER compensation beyond the full cost of traditional infrastructure solutions reflected in utility Marginal Cost of Service (MCOS) studies. Given affordability concerns, DRV and LSRV compensation should not exceed the cost of traditional electric system upgrades that

---

[4] VDER Proceeding, Joint Utilities' Comments on DPS Staff Proposal on Updating DRV and LSRV for VDER Compensation (filed March 16, 2026) (Joint Utilities' Initial Comments).

[5]As stated in the VDER Proceeding, Joint Utilities' Initial Comments (p. 4): 1) solar deployment across upstate New York has already met 98% of 2030 NY-Sun program solar targets, and 2) downstate distribution-connected storage deployment is particularly advanced – in Con Edison's service area, energy storage is on track to double its share of the 2030 State Storage Roadmap targets, with 1 GW of energy storage either interconnected or with executed New York State Standardized Interconnection Requirements (SIR) agreements and VDER compensation elected.

are available at all hours throughout the year. The MCOS should be considered the maximum compensation available such that any difference between the MCOS ceiling and the price needed to drive the market results in utility customer benefit, and not incremental market compensation.[6] This idea was reflected in the Staff Proposal: "To the extent that a VDER project can enter the market and survive, or even profit, with DRV plus LSRV set at a level below the MCOS for that area, that VDER project should result in a savings of societal resources."[7] The Joint Utilities maintain that revisions to the DRV and LSRV frameworks should be largely guided by customer value and should not increase customer costs without clear demonstration of corresponding benefits. Lastly, several commenters provided recommendations that are beyond the scope of the Staff Proposal and the corresponding Notice Soliciting Comments[8] or conflict with prior orders from the New York State Public Service Commission (Commission) and therefore should be rejected by the Commission.

II. DRV framework should maximize value at the lowest cost for utility customers

Requests for eligibility changes for new DRV rates

The City and Clean Energy Parties recommend that Staff's proposed DRV rate eligibility be applied retroactively to DER projects currently in the queue that have signed interconnection agreements. The City, for example, recommends the updated DRV rate be applied to projects that paid their full interconnection payment after the date the Staff Proposal was issued (i.e., post-December 11, 2025),[9] while Clean Energy Parties recommend an opt-in option for projects that paid their 25 percent interconnection deposit on or after the MCOS study release deadline (June 30, 2025).[10] In contrast, the Other Developers suggest the eligibility criteria be

[6] In their initial comments, the Joint Utilities included a proposal for adding competition to DRV in areas of the system where distribution peak shaving capacity is limited. Such an approach can generate utility customer cost savings in instances in which DERs can deliver peak shaving at a cost lower than MCOS. *See* VDER Proceeding, Joint Utilities' Initial Comments, p. 14.
[7] VDER Proceeding, Staff Proposal, p. 7.
[8] VDER Proceeding, Notice Soliciting Comments (issued December 31, 2025) and as further extended in Notice Extending Comment Deadlines (issued February 24, 2026) (Notice).
[9] VDER Proceeding, City of New York Comments (filed March 16, 2026) (City Comments), p. 8.
[10] VDER Proceeding, Clean Energy Parties Comments in Response to the Department of Public Service Staff Proposal on Updating DRV and LSRV for VDER Compensation (filed March 16, 2026) (Clean Energy Parties Comments), p. 6.

delayed until 90 days after the Commission approves the new DRV rate but only for projects in the Orange and Rockland service territory.[11]

Applying the proposed DRV rate eligibility retroactively to projects that have paid deposits, as proposed by the City and Clean Energy Parties, would impose incremental costs on utility customers with no incremental value, exacerbating affordability impacts. These projects have already paid deposits and are therefore deemed feasible and market financeable and are moving through the construction phase leading to interconnection. In Con Edison's service area alone, retroactive application of new DRV rates for energy storage projects would result in an additional \$25 to \$130 million in compensation over ten years,[12] with no new value created.

If the Commission considers any approach that extends updated DRV rates to a subset of queued projects, those projects should be required to also meet the Joint Utilities' proposed value-based eligibility and availability construct. Under this framework, utilities would have the ability to identify locations where incremental peak shaving is still available and apply the appropriate DRV windows and compensation for these areas. Utilities would also have the ability to identify locations where incremental DER discharge would not result in local distribution peak reduction and therefore would have no opportunity for DRV compensation. For example, in the Con Edison service area alone, concurrently applying the Joint Utilities' proposed changes to the DRV framework to projects in the interconnection queue will not only avoid incremental cost increases to non-participating Con Edison customers from the other parties' proposals, but also result in further cost savings of more than \$100 million. In addition, the Joint Utilities' proposal would expand the value of the compensated projects by ensuring they only get paid when reducing the distribution peak.

Furthermore, any retrospective application of new DRV rates and eligibility criteria should not be on an "opt-in" basis, as proposed by Clean Energy Parties. An opt-in approach is

---

[11] VDER Proceeding, Carson Power, New Leaf Energy and Sol Source Power Comments (filed March 16, 2026) (Other Developers Comments), pp. 2-3.

[12] Based on the SIR queue of energy storage projects through February 2026. Con Edison's analysis applies \$252/kW DRV to the additional MWs that either paid the full interconnection payment after December 11, 2025 (per the City Comments' proposal) or paid the 25% interconnection deposit since June 30, 2025 (per Clean Energy Parties Comments' proposal) and compares it to the \$199/kW DRV currently locked in by these MWs. Applying the \$380/kW DRV proposed by Clean Energy Parties would further increase the \$130 million in additional costs being borne by Con Edison customers to \$430 million.

inconsistent with a value-based construct because it invites strategic selection by DER developers of whichever framework yields higher payments, rather than achieving the Commission's objective to provide DER with compensation "for the value they create."[13] The opt-in proposal is at odds with the principle of ensuring the best value for utility customers. The Joint Utilities strongly recommend that if any retrospective eligibility is adopted by the Commission, it should not be structured as an opt-in mechanism.

Requests to extend DRV lock-in period

NineDot proposes to extend the DRV rate lock-in period from 10 years to 15 years.[14] The Joint Utilities disagree with this proposal for the reasons that: extending the DRV lock-in period for 5 additional years risks relying on outdated data as the MCOS calculations are based on a 10-year forecast; the existing 10-year lock-in has provided sufficient revenue certainty to support DER market development; and any extension should be evaluated in the context of overall tariff design and deliver meaningful incremental value.

First, the MCOS studies that are used to determine the DRV are based on projected capital additions over a 10-year period. Extending the DRV lock-in period introduces uncertainty to the presumed value DERs may provide to the distribution grid beyond the 10-year period. In fact, the Commission originally envisioned the DRV to reset for all resources every three years, "so that it may dynamically evolve as calculation methodologies are improved and as the underlying values themselves change and so that utilities are compensating projects based on their actual impacts on utility costs."[15] Extending the lock-in period misaligns peak-shaving price signals because future marginal costs have the potential to be substantially different than those included in the 10-year MCOS and DRV calculation.

Second, the current 10-year DRV lock-in period has provided DER developers with sufficient revenue certainty. The Value Stack compensation mechanism has supported a robust

[13] VDER Proceeding, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017), p. 19.
[14] VDER Proceeding, NineDot Energy Comments (filed March 17, 2026) (NineDot Comments), p. 7.
[15] VDER Proceeding, Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues and Related Matters (issued September 14, 2017) (Phase One Order), pp. 12-13.

DER market. In Con Edison's service area, as one example, there are over 1 GW of energy storage in operation or with executed interconnection agreements with the DRV locked in.

Finally, the duration of lock-in periods should consider all operational and financial parameters, including operational flexibility and incremental value provided by DERs. Time periods for contracts associated with utility programs vary and are determined based on unique operational parameters and program goals. For example, the Con Edison Bulk Energy Storage Request that NineDot references as a 15-year program specifies a number of operational requirements, such as providing the utility with dispatch rights, rather than simply energy storage receiving Value Stack compensation. Therefore, any extension in the duration of the lock-in period should be considered in the broader context of programmatic requirements.

Proposal to maintain DRV discharge only over four-hour windows in the summer

In its comments, NineDot correctly identifies that the existing DRV framework includes "shortcomings," including "static pricing signals that do not provide temporal differentiation" and "four-hour export windows are fixed for ten years, even as local load curves shift."[16] NineDot also correctly illustrates that the four-hour export window has the effect of creating dual peaks on both sides of the export window, while not effectively reducing the local peak, as explained in the Joint Utilities' Initial Comments. As such, the Joint Utilities agree with NineDot's assessment that the existing DRV framework's operational requirements are limiting. The Joint Utilities also agree that any successful DRV framework today should set the DRV compensation early in the development cycle and provide a 10-year rate lock, with a well-defined operating profile. Accordingly, the Joint Utilities' Initial Comments recommended DRV eligibility and operational criteria design changes in line with these principles, balancing robust market support with value to customers while considering affordability.

Despite the identified DRV framework shortcomings, NineDot proposes a "bankable 10-year rate lock" with four-hour summer, non-holiday, non-weekend blocks, which contradicts their own assessment of the operational shortcomings.[17] As discussed in the Joint Utilities' Initial Comments, to effectuate actual peak reduction on the distribution system, DRV windows should evolve to address weekends, later peaks, and winter periods, as well as widen beyond four hours.

[16] VDER Proceeding, NineDot Comments, p. 31.
[17] *Id.*, p. 32.

Furthermore, in locations where load shapes are sufficiently flat such that incremental DER discharge will not result in reduction of the local distribution peak, there should be no opportunity for DERs to receive compensation for the DRV component of the Value Stack. Therefore, the Commission should reject NineDot's recommendation to strictly limit DRV discharge to summer weekdays for only four-hour windows, which would maintain the existing limited operational flexibility to dispatch DERs.

III. LSRV design should maintain simplicity and avoid further increasing costs for non-participating utility customers

"LSRV-Alt2" concept and related proposals

As noted above, NineDot correctly recognizes that several key changes are required for DRV and LSRV constructs to better address grid needs, and ultimately provide value to the grid, such as evolution beyond four-hour export windows, shifting of dispatch windows over time, and event calls during winter and summer.[18] While proposing no changes to DRV, NineDot proposes changes to the LSRV framework alone, further increasing DER compensation above MCOS. To best align compensation with value to utility customers, changes to DER dispatch price signals aligned with system needs should be applied in equal measure to both DRV and LSRV. The eligibility and operational changes for DRV and LSRV proposed in the Joint Utilities' Initial Comments achieve better alignment between DER compensation, grid needs, and customer value.

Furthermore, NineDot's proposal for an LSRV-Alt2 compensation creates program confusion and reliability risk by mixing performance that addresses distribution needs and transmission security needs within the same program.[19] This is problematic for two reasons. First, the LSRV, as the name implies, is designed specifically to address locational distribution issues in local areas of the grid.[20] Second, a single asset cannot be relied upon for planning or as an operational tool to meet distinct needs at different levels of the system, which are independent and can evolve separately. For example, dispatch windows for distribution and transmission may not always align as local and shared needs may change over time. Instead, a hierarchy of grid

[18] *Id.*, p. 31.
[19] *Id.*, p. 34.
[20] VDER Proceeding, Phase One Order, p. 14.

services must be established with a primary grid need identified, even if there may be benefits extracted at other levels of the system at the same time. Specifically, the Value Stack construct was designed to compensate DER for distribution level benefit, and therefore, proposals for solutions designed to address transmission reliability are out of the scope of this proceeding.[21]

In cases where grid constraints limit a project's ability to charge without creating additional risk, NineDot's proposal essentially argues that additional compensation should be provided for performance during "LSRV Grid Constraint" events on a per MWh basis to reward these assets for not creating grid operational issues that would not otherwise exist.[22] Proposals for such additional and unwarranted compensation will result in LSRV-eligible resources being compensated well above the full MCOS value and should therefore be rejected.

Request to extend LSRV lock-in beyond two years

NYPA's proposal to allow projects to lock in their LSRV rate before making an interconnection deposit or executing an agreement under the SIR is not appropriate. NYPA also suggests that these LSRV-eligible resources retain LSRV compensation rates for 1-2 years after utilities update their MCOS.[23] As with the above noted comments of other parties proposing changes to the DRV eligibility criteria, NYPA's proposal for LSRV contrasts with the Commission's clear direction that eligibility be determined when a project pays their interconnection costs or executes an interconnection agreement. Extending the LSRV lock-in period beyond the current standard risks perpetuating DER compensation above MCOS where deferral opportunities no longer exist. Furthermore, this undermines the alignment of LSRV with utilities' actual ability to defer traditional infrastructure—an alignment the Joint Utilities expressly proposed, including the utility screening of LSRV areas for deferral feasibility and timeliness. As noted in the Joint Utilities' Initial Comments, historical data show that the average time to reach the 25% interconnection downpayment stage is approximately one year from the date the application is submitted. For this reason, the Joint Utilities reiterate that LSRV be

[21] *E.g.*, Con Edison's transmission security needs are being addressed in Case 25-E-0764, *Proceeding on Motion of the Commission to Address New York City Reliability Needs*.
[22] VDER Proceeding, NineDot Comments, p. 38.
[23] VDER Proceeding, New York Power Authority Comments (filed March 16, 2026) (NYPA Comments), p. 2.

reserved only for projects that meet in-service date requirements to provide an opportunity for utilities to actually avoid distribution system costs.[24]

Request for separate LSRV regulatory track

Clean Energy Parties "request a two-part approach [to DRV and LSRV] 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."[25] The Joint Utilities support timely Commission action but note that DRV and LSRV reforms are interdependent, with close linkage between DRV and LSRV operational requirements. The Joint Utilities believe that separating LSRV in its own regulatory track to be addressed after changes to DRV are determined has the potential to add unwarranted complexity and therefore should be avoided. Operational requirements for LSRV should be assessed in tandem with those for DRV (*e.g.,* extending dispatch windows), and the Joint Utilities, as well as other commenters, have provided detailed recommendations in their comments that can form the basis of Commission action across both DRV and LSRV.

IV. Transparent and practical reporting of DRV and LSRV effectiveness should be adopted

Clean Energy Parties and NineDot propose expansive reporting and success metrics for the updated DRV and LSRV frameworks.[26] The Joint Utilities support transparent, practical tracking that allows stakeholders to evaluate whether DRV and LSRV are operating as intended, but emphasize that metrics should provide value to the proceeding (*i.e.,* should be tied to specific decision-making), and be rightsized, administratively feasible, and tied to data that utilities already possess, rather than creating new reporting constructs that would be costly to implement or that could invite misleading attribution claims.

As indicated in the Joint Utilities' Initial Comments,[27] each utility already reports on interconnected DER and the cost recovery of VDER credits in their respective VDER Cost Recovery Statements. In addition, the Joint Utilities propose to report both annual expenditures

[24] VDER Proceeding, Joint Utilities' Initial Comments, p. 15.
[25] VDER Proceeding, Clean Energy Parties Comments, p. 7.
[26] *See* VDER Proceeding, Clean Energy Parties Comments, p. 16 and NineDot Comments, pp. 44-45.
[27] VDER Proceeding, Joint Utilities' Initial Comments, p. 16.

and the capacity (MW) of DRV and LSRV resources, which will enable parties to calculate the unit cost in $/MW for each.

NineDot proposes metrics associated with quantifying deferred or avoided investments or metrics tied to changes in peak load forecasts.[28] The Joint Utilities do not support these as standalone metrics for DRV and LSRV success because infrastructure investment decisions and the forecasts that drive them incorporate multiple inputs—including load growth, other flexible programs (e.g., demand response), and other system conditions. Similarly, a static utilization metric risks misrepresenting system value and driving unintended outcomes that are disconnected from actual grid or customer needs (such as penalizing discharge from solar resources or energy reductions from energy efficiency upgrades or promoting the reduction of excess system capacity in the evenings that is used to cool electrical equipment). Increasing utilization should not be treated as an end to itself; additional utilization only provides value to customers when that usage directly addresses a grid or customer need.

If additional reporting requirements are adopted by the Commission that include data the Joint Utilities do not already possess or require incremental information system investments, the utilities should be allowed to recover associated implementation costs in a timely manner.

V. The MCOS methodology adopted in Commission's August 2024 Order should not be reopened

A number of parties request substantive changes to the utility MCOS studies that were filed on June 30, 2025. However, the Staff Proposal focuses only on how the Joint Utilities' MCOS values should be used to set the DRV and LSRV values. Substantive changes to the MCOS methodology the Commission approved in its MCOS Order[29] are beyond the scope of issues the Commission should consider in this context. Even if the Commission were to consider the merits of such changes, they should be rejected.

The MCOS Order directed the Joint Utilities to employ a traditional National Economic Research Associates (NERA) methodology in the development of their MCOS studies. The NERA methodology is grounded in an engineering and planning approach, with marginal costs

---

[28] VDER Proceeding, NineDot Comments, p. 45.
[29] VDER Proceeding, Order Addressing Marginal Cost of Service Studies (issued August 19, 2024) (MCOS Order).

determined based on each individual utility's planning practices.[30] As such, it considers the unique nature of the Joint Utilities' electric systems, service areas, and customer base. Therefore, while adhering to the MCOS Order, the Joint Utilities' MCOS studies can reasonably differ, reflective of these considerations. Similarly, in discussing certain modifications to the traditional NERA methodology, the MCOS Order acknowledges that this methodology relies on the Joint Utilities' individual capital plans and therefore does not prescribe absolute uniformity when it comes to the core provisions of the Joint Utilities' MCOS studies.

The Joint Utilities note that, if adopted by the Commission, those parties' comments proposing such changes will require recalculation of each utility's MCOS, resulting in delayed implementation of the updated DRV and LSRV values. Further, each of the proposed changes has the effect of increasing the MCOS, and in turn, the DRV and LSRV compensation. Substantive changes to the MCOS methodology would impact other proceedings that utilize a Benefit Cost Analysis to evaluate the cost-effectiveness of other programs, such as demand response.

Request to use load served instead of installed capacity

Clean Energy Parties propose to change the MCOS calculations to focus on incremental load instead of project capacity additions.[31] In the NERA MCOS engineering-based methodology, estimating the marginal cost per kW of load-carrying capacity is a key design element. This is because when facilities need reinforcement to meet load growth, it makes sense to upgrade them with equipment that will solve more than the immediate incremental demand need. It does not make economic or practical sense to expand system capacity to just meet the currently forecasted load growth, especially in today's era of electrification and associated load growth where loads are expected to continue to increase significantly.

Two key factors affect the utility planning practice. First, the lumpiness of investment driven by economies of scale means that larger incremental capacity additions cost less to build on a per kW basis, compared to incremental additions of smaller standard equipment over time. Second, in many cases it is also not possible to add a small incremental amount of capacity to

[30] *Id*., p. 9.
[31] VDER Proceeding, Clean Energy Parties Comments, p. 3.

match near-term peak load growth due to how the system is designed. For example, an additional supply to a substation must be the same capacity as the existing supplies if they are to be operated in parallel. Thus, an increase in peak load growth generally triggers capacity additions that are larger than near-term capacity needs at a given time, consistent with the utility least-cost approach to planning. Estimating per-kW costs based on added load carrying capacity of the planned installed equipment, under applicable contingency conditions, reflects the unit cost per amount of load growth that the deferred or avoided investment would be able to support over time.

Request to use "verifiable" costs

Clean Energy Parties request future MCOS studies to be based on "verifiable project costs".[32] In discussing the merits of a traditional NERA approach, the Commission's MCOS Order notes that the NERA method relies upon the costs of actual projects that are included in the Joint Utilities' capital plans,[33] and that the estimated costs of these projects are submitted and reviewed in multi-stakeholder rate cases. As such, investment costs presented in the Joint Utilities' MCOS studies are subject to rigorous regulatory scrutiny and do not merit additional burdensome reporting requirements. Furthermore, there can be inherently different project details due to substantial timing differences between rate cases, capital plans, and the utilities' DSIP/MCOS studies.

Request to include investments that do not increase system capacity

NineDot argues for the inclusion of load transfer costs in the MCOS studies because these costs are included in utility rate cases and allow utilities to meet localized near-term load growth under certain conditions.[34] As noted above, the traditional NERA methodology relies on including capacity solutions where the investment's added full load carrying capacity naturally creates excess capacity on the system. While load transfers can support meeting customer loads, they simply shift existing capacity across the system, mainly to avoid localized risk of curtailment, and do not increase the amount of capacity the system can serve overall. Importantly, load transfers are temporary in nature, as a corrective action primarily addressing

32 *Id*., p. 7.
33 VDER Proceeding, MCOS Order, p. 9.
34 VDER Proceeding, NineDot Comments, p. 9.

current thermal overloads (existing N-0 constraints). Load transfers can occur at the individual distribution load area level, where portions of the load in one area may be transferred to another to share existing capacity, and at the area station level where load served by one area station may be transferred to another. In contrast, area load *growth* forecasted throughout the MCOS study is more appropriately addressed through system upgrades or capacity expansion. There may be very specific exceptions where a load transfer is driven not just due to required capacity expansion on the feeder or station or imminent N-0 violations, but redistributes available capacity to accommodate load at the particular location. Such load transfers may delay any further capacity relief action in the area. However, they do not create net additional capacity on the system and do not negate the need for continued system investment. Overall, inclusion of load transfers systematically in the MCOS study would distort the system-wide average cost per kW of new carrying capability to meet new growth and should be ignored.

Proposals for use of historical costs

NineDot recommends deviating from the established NERA methodology and fundamentally changing the MCOS calculation by including historical costs for substations and transmission, arguing that "[t]o the extent that a [Battery Energy Storage System] BESS can defer the building of these assets, the project costs should remain in the asset base used to calculate MCOS."[35] The Joint Utilities disagree and note that once a utility commits to building a traditional infrastructure project, no amount of additional energy storage can defer the investment. In addition, by excluding substation areas that do not have planned capital projects during the MCOS study's time horizon from the MCOS calculation, Staff's Proposal already avoids the potential for artificially low marginal costs after completion of the traditional utility project.[36]

Proposals for projects in construction

NineDot questions the accounting for costs and MWs prior to projects going into service.[37] The traditional NERA MCOS methodology involves a phase-in of a project's per-kW cost of its load carrying capability from the need date through the in-service date, during the

[35] *Id*., p. 8
[36] VDER Proceeding, Staff Proposal, p. 4.
[37] VDER Proceeding, NineDot Comments, pp. 14-16.

study's time horizon. This unit cost is phased in to reflect the utility's construction schedules. Con Edison and O&R followed this approach. NYSEG and RG&E applied a slightly different approach to handle the calculation of marginal cost for each year during the phased-in construction period, to capture not only the time value of the investments but also the time profile of capacity additions. In its original MCOS filing,[38] National Grid applied an inflation factor from the in-service-year to discount prior years' MCOS while conversely inflating the MCOS value in post-in-service years. However, National Grid's supplemental filing,[39] used a straight inflation escalation for the 10-year period without any discount to the substation's prior years' MCOS. In its MCOS filing,[40] Central Hudson used an inflation-adjusted MCOS value in post-in-service years. Compared to the NERA traditional model, these differing approaches are computational refinements that fit the overall intent of the study, i.e.*,* presenting a result in levelized terms.

Proposed changes to National Grid's MCOS

The Clean Energy Parties' proposal to revise National Grid's MCOS calculation should be rejected for a number of reasons. First, while the transmission allocation methodology proposed by the Clean Energy Parties' provides additional granularity beyond what was detailed in the Staff Proposal, it continues to rely on a general allocation of all transmission projects across the substations listed in the MCOS calculation (i.e.*,* those substations identified as needing system upgrades). Further, the proposal does not apply the specific transmission project capacity and costs only to those substations that will benefit from such upgrades. Conversely, in their response to Staff's questions, the Clean Energy Parties support allocating transmission projects' cost and capacity if they "can be identified as benefiting specific substation areas or a region of the utilities' transmission system."[41]

As noted in National Grid's supplemental filing,[42] a proximity-based allocation method was used to apply the total capacity added from the system-wide transmission project to specified locations in close proximity that will benefit from such an upgrade – including

[38] VDER Proceeding, National Grid MCOS Study (filed June 30, 2025).
[39] VDER Proceeding, National Grid Revised MCOS Study (filed March 16, 2026).
[40] VDER Proceeding, Central Hudson MCOS Study (filed June 30, 2025).
[41] VDER Proceeding, Clean Energy Parties Comments, p. 16.
[42] *Supra* note 39.

substations that were not in the Company's 2025 MCOS Study as those substations were not identified as requiring specific multi-year distribution upgrades (i.e.*,* non-zero marginal costs). The Clean Energy Parties' proposed method, as well as Staff's proposed method, fails to account for transmission projects' benefit to those substations not included in the original 2025 MCOS Study, contributing to an inflated system average MCOS value. The transmission projects' computed MCOS should not arbitrarily be assigned to other substations as all transmission projects do not benefit each substation included in the MCOS study and may, in fact benefit substations not included in a non-zero marginal cost study. As explained in its supplemental filing,[43] in the next iteration of the DSIP filing National Grid intends to utilize a more precise allocation study to determine "impact factor" of load or generation interconnections to underlying substations to best understand the upgrade's impact of upstream transmission line loading under various scenarios consistent with grid planning best practices. This impact-factor study would then provide a more specific value to allocate transmission project capacity and costs to identified substations where capacity is most directly served by transmission projects providing further granularity to transmission project allocation.

Furthermore, the Clean Energy Parties use an arbitrary and irrelevant "materiality threshold" in the calculation of each of National Grid's substation's MCOS value that overinflates certain substation MCOS results that are "in excess of the materiality threshold." Lowering this subjective threshold arbitrarily increases the revised system average MCOS while raising the threshold results in the inverse action. The Clean Energy Parties fail to justify the use of such a threshold and do not consistently use this methodology in the other utilities' MCOS calculation. Therefore, the Commission should reject the use of any such threshold in the MCOS calculation.

In their comments, the Clean Energy Parties provide a table describing the differences in the Joint Utilities' MCOS methodologies and specifically identify National Grid as an outlier in the segmentation approach.[44] In its MCOS filing, National Grid categorized upgrades based on the type of upgrade to be completed and then combined the various upgrades at a given substation. The Clean Energy Parties' assumption that the upgrades were incorrectly combined

[43] *Id*.
[44] VDER Proceeding, Clean Energy Parties Comments, p. 9.

overlooks the fact that certain projects are intentionally grouped because they jointly resolve a single, system-identified constraint. In these cases, the transmission and distribution components are not independent or additive; rather, they are interdependent elements of one parent project that must all be completed to deliver the required capacity. Because the final capacity outcome is produced only by the full suite of grouped work, separating the costs or capacities into individual asset segments would misrepresent the true cost structure and artificially overstate incremental capacity. For constraint-driven parent projects, the appropriate approach is to treat the grouped upgrades as a single integrated investment, not as separable transmission and distribution additions. Only standalone projects that address a single asset segment independently are suitable for individual MCOS calculations.

As described in both the Clean Energy Parties' comments and NineDot's comments,[45] National Grid's MCOS workpapers included an inflation factor when calculating the net present value, whereas other utilities utilized a weighted average cost of capital (WACC) factor. National Grid agrees that the post-tax WACC is the appropriate tool for calculating the net present value and provided such in its updated MCOS workpapers.[46] However, the Clean Energy Parties further adjusted this calculation using a discounted WACC factor based on in-service date[47] that is unnecessary as the use of inflation in the 10-year cost calculation in addition to a WACC discounting factor would be duplicative. If more precise WACC factors are required, a more appropriate method would be to use the various yearly WACC rates as approved in the utilities' multi-year rate cases by applying future known WACC rates to outer years. However, this approach would be suboptimal given the differing cadence of rate case proceedings by the various utilities and the relatively short, typical three-year rate plan period. Therefore, the Commission should reject the Clean Energy Parties proposed discounted WACC factor in the MCOS calculation and continue to utilize the single, most up to date WACC rate across the 10-year MCOS calculation.

---

[45] *See id*. and VDER Proceeding, NineDot Comments, p. 15.
[46] *Supra* note 39.
[47] VDER Proceeding, Clean Energy Parties Comments, p. 22.

VI. Comments that are inaccurate should be rejected

DRV purpose and relationship with avoided customer costs

The City commented that, "The DRV was designed to reflect DERs' ability to inject energy onto the grid during demand peaks to reduce load, thereby avoiding or deferring the need for costly traditional investments in utility infrastructure."[48] The Joint Utilities agree with the City that DRV's design was in fact intended to incentivize DER injection during peak demand hours. However, as the Joint Utilities have explained, the existing operating framework for DRV, which limits DER injections in narrow four-hour windows in every part of the distribution system, results in DER injections that do not always align with reducing the peak and can create dual peaks outside the existing four-hour window.[49]

Furthermore, injections during peak demand hours do not always result in cost avoidance through the reduction of infrastructure investments because infrastructure investments are only required in certain parts of the system, not everywhere. DER injections during peak demand hours in parts of the system where system capacity exceeds the forecasted load will not result in any avoided system costs or customer bill savings because infrastructure projects would not be planned for those parts of the system.

Clean Energy Parties highlighted in their comments that, "the DPS Staff Proposal will lower energy supply charges by catalyzing DER deployment," and cited a recent study by Synapse Energy Economics that evaluated the impact of solar and energy storage deployment on energy costs.[50] After reviewing the Synapse Energy Economics study, the Joint Utilities are unable to assess how realistic the study estimates are as the study appears to be based on gross energy benefits without considering the compensation that DERs receive.[51] Netting out the DER compensation, which is funded through non-participating customers, would result in lower customer bill savings. The Joint Utilities' Initial Comments describe why the distribution value construct must be right-sized for customer affordability. For example, in Con Edison's service

---

[48] VDER Proceeding, City Comments, p. 2.
[49] VDER Proceeding, Joint Utilities' Initial Comments, p. 9.
[50] VDER Proceeding, Clean Energy Parties Comments, p. 6.
[51] *See* Synapse Energy Economics, *Sunlight and Storage into Savings: Evaluating Energy Cost Savings from Distributed Solar and Storage Additions in New York* (January 2026), *available at* https://www.synapse-energy.com/new-york-distributed-solar-and-storage-savings.

area, nearly $2 billion of DRV compensation has already been committed to interconnected energy storage projects over the next ten years.[52] And if all queued projects interconnect, DRV compensation could grow to over $5 billion over ten years, equivalent to approximately a 4% customer bill increase. In contrast, 94% of projects[53] in the queue do not deliver commensurate distribution peak reduction value under current rules.

Utility preference for other programs

NineDot comments, "while DRV has driven a market for DERs in Con Edison's territory, Con Edison has shown preference for other programs to provide locational relief such as the Dynamic Load Management and Non-Wires Solutions programs given their higher requirements for dispatchability and performance contracts."[54] NineDot adds, "these other programs are opaque and administratively burdensome to scale, increasing costs for ratepayers."[55] The assertion that Con Edison has shown preference for NWAs and Dynamic Load Management (DLM) over VDER resources is incorrect. These programs have a defined process that is prescribed in Commission orders, and Con Edison has implemented such programs in accordance with Commission directives with great success.[56]

Furthermore, the Joint Utilities disagree with the assertion that NWAs and DLM programs are administratively burdensome and maintain that these programs provide better value for utility customers. First, NWA portfolios and DLM resources are both subject to benefit-cost analyses and also must maintain costs below the benefits generated for society.[57] Second, NWA portfolios and DLM resources are procured through competitive solicitations to ensure the lowest costs possible for utility customers, which is not the case for resources receiving DRV and LSRV

---

[52] VDER Proceeding, Joint Utilities' Initial Comments, p. 4.

[53] This analysis is based on recent queue analysis with the existing 4-hour DRV window. The analysis will change as more DER contracts are assigned a 4-hour window, reducing the beneficial distribution peak shaving energy storage projects remaining.

[54] VDER Proceeding, NineDot Comments, p. 5.

[55] *Id*., p. 6.

[56] *See* Case 15-E-0229, *Petition of Consolidated Edison Company of New York, Inc. for Implementation of Projects and Programs that Support Reforming the Energy Vision* (NWA Proceeding), Order Implementing with Modification the Targeted Demand Management Program, Cost Recovery, and Incentives (issued December 17, 2015) (TDM Order); *see also* Case 18-E-0130 *In the Matter of Energy Storage Deployment Program* (Storage Proceeding), Order Establishing Term-Dynamic Load Management and Auto-Dynamic Load Management Program Procurements and Associated Cost-Recovery (issued September 17, 2020) (Term- and Auto-DLM Order).

[57] *See* NWA Proceeding, Order Approving Shareholder Incentives (issued January 1, 2017), p. 4; *see also* Storage Proceeding, Term- and Auto-DLM Order, p. 53.

compensation.[58] Third, NWA portfolios include diverse resource types, such as energy efficiency, that can be assembled to provide load reductions over more hours, unlike load reductions that can be achieved through battery energy storage export or solar generation alone.[59] Finally, NWA agreements are structured to include operational flexibility that allows utilities the ability to change dispatch windows as well as operational requirements to ensure DER performance. As proposed in the Joint Utilities' Initial Comments, there is an opportunity to increase the cost-effectiveness of DRV and LSRV by introducing similar operational flexibility and requirements[60] as well as introducing competition for DRV in areas of the electric distribution system where peak shaving capacity is limited. Introducing competition for DRV could encourage the market to offer load relief at the lowest cost possible.[61]

Dispatchable DERs ability to eliminate and defer traditional upgrades

The Joint Utilities disagree with the approach and conclusions drawn from NineDot's Appendix 1 example comparing a traditional solution to an energy storage solution.[62] In the example, NineDot asserts that additional energy storage can eliminate the need for traditional load relief due to load growth. To make that assertion, one must look at both the magnitude of the need (in MW) and the duration of the need (i.e., the hours of overload each year).

In the case of Con Edison's Corona No. 1 area substation, there is an initial four-hour peak shaving need that grows into a five-hour peak shaving need the second year, and a seven-hour peak shaving need in the following years. The traditional solution could possibly be deferred in the first year, provided there is flexibility to align the battery discharge window to the same four hours as the peak shaving need. With the battery capacity assumed in NineDot's example, the need to invest in traditional infrastructure could potentially be deferred for additional years if the DRV tariff was revised to include longer discharge windows of six and eight hours. As time progresses, the duration of the peak shaving need grows beyond the load

[58] *See* NMA Proceeding, TDM Order, p. 8; *see also* Storage Proceeding, Term- and Auto-DLM Order, p. 2.
[59] *See* NWA Proceeding, Con Edison Benefit Cost Analysis: Newtown Non-Wires Solutions Project (filed June 2020), p. 3.
[60] VDER Proceeding, Joint Utilities' Initial Comments, pp. 7-13.
[61] *Id.*, p. 14.
[62] VDER Proceeding, NineDot Comments, p. 47.

reduction that could be achieved even with an eight-hour discharge window, and therefore the traditional solution would still need to be built.

Therefore, it is not accurate to use the total cost of the traditional solution as the amount of savings achieved through the energy storage solution. Rather, the value lies in the number of years of deferral achieved. Based on the existing DRV framework, the energy storage solution would at most achieve a one-year deferral of the traditional solution. Assuming the adoption of the operational changes proposed in the Joint Utilities' Initial Comments to extend DER discharge windows beyond four hours, the energy storage solution could potentially defer the need for the traditional solution by only a few additional years.[63]

Similarly, Con Edison disagrees with the conclusion from NineDot's analysis that 110 MW of DER projects within the Bensonhurst No. 2, Water Street, and Brownsville No. 2 area substations can avoid $5.9 billion in traditional infrastructure costs.[64] The duration of peak-shaving hours in these areas exceeds the four-hour dispatch windows and therefore the DER projects' deferral potential is limited after a short number of years under current Value Stack tariffs. Transmission-level needs are also a driving factor for some infrastructure projects in the cited area substations, therefore focusing the analysis only on distribution capacity for this specific example is not comprehensive.

NineDot also references Con Edison's Jamaica area substation as an example that "demonstrates the grid benefits of DRV operations for an average week during the summer period."[65] Con Edison notes that there is currently minimal dispatchable Value Stack resources in the Jamaica area substation;[66] most of the current peak reduction during this area's Commercial System Relief Program window comes from demand response resources, with a smaller but growing amount of resources from Con Edison's NWA portfolio. Therefore, it is not clear how this example demonstrates the grid benefits of DERs operating in response to DRV price signal.

[63] VDER Proceeding, Joint Utilities' Initial Comments, pp. 8-9.
[64] VDER Proceeding, NineDot Comments, p. 26.
[65] *Id.*, p. 30.
[66] Approximately 1 MW of dispatchable VDER resources are currently located in the Jamaica network.

VII. Issues that are beyond the focus of the Notice and already being addressed in other, more appropriate proceedings and should not be considered here

The City's recommendations regarding SIR queue management and the study methodologies used by Con Edison in evaluating SIR projects should be considered in the SIR proceeding.[67] Likewise, the City has already commented on its recommendations to change the SIR process in the Interconnection Policy Working Group (IPWG) and Interconnection Technical Working Group (ITWG).[68]

NineDot reiterated a proposal for a Bidirectional Service Classification made by NY-BEST, which NineDot is a member of, in a filing in the Grid of the Future Proceeding.[69] The Staff Proposal, which is the subject of these comments, addresses Value Stack compensation for discharging, not charging rates and therefore is outside the scope of this proceeding.

Clean Energy Parties' request that DLM rates be updated to reflect the new MCOS values.[70] The Joint Utilities note that under the terms of the 2020 Order establishing the Term-Dynamic Load Management and Auto-Dynamic Load Management programs, these are competitive solicitations rather than rates, with the evaluation criteria defined under the terms of the Order and utility procurement documents.[71]

Clean Energy Parties' request to update the Value Stack Environmental Value (E-Value)[72] would, as their comments suggest, need to be considered along a parallel track rather than as part of the present discussion and is therefore outside the scope of this proceeding.

---

[67] Case 24-E-0621, *In the Matter of Modifications to the New York State Standard Interconnection Requirements and Application Process for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems* (SIR Proceeding).
[68] SIR Proceeding, City of New York Comments Regarding DPS's Straw Proposal for Interconnection Queue Management (filed December 10, 2025), p. 7.
[69] Case 24-E-0165, *Proceeding on Motion of the Commission Regarding the Grid of the Future* (Grid of the Future Proceeding), NY-BEST Comments on the Grid Flexibility Potential Study and the First Iteration of the Grid of the Future Plan (July 15, 2025), p. 4.
[70] VDER Proceeding, Clean Energy Parties Comments, p. 13.
[71] Storage Proceeding, Term- and Auto-DLM Order, p. 5.
[72] VDER Proceeding, Clean Energy Parties Comments, p. 14.

VIII. Conclusion

The Commission should adopt DRV and LSRV operational reforms that align compensation with distribution peak reduction value, including the principle that DRV may not be appropriate in local areas where incremental peak shaving is exhausted. Furthermore, the Commission should provide utilities the option to offer DRV competition where peak shaving capacity is limited so as to yield maximum value at the lowest cost to customers. Finally, the Commission should reject commenters' proposals that expand eligibility or increase compensation without a demonstrated ability to avoid distribution costs and provide customer value.

Dated: April 6, 2026

Respectfully submitted,

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. and ORANGE AND ROCKLAND UTILITIES, INC.

By: */s/* Christian Malanga

Christian Malanga
Senior Attorney
Consolidated Edison Company of New York, Inc.
4 Irving Place
New York, New York 10003
Tel: (917) 838 - 9513
Email: malangac@coned.com

CENTRAL HUDSON GAS & ELECTRIC CORPORATION

By: */s/ Marina W. Chu*

Marina W. Chu
Regulatory Attorney
Central Hudson Gas & Electric Corporation

284 South Avenue
Poughkeepsie, NY 12601
Tel: (845) 452-2000
Email: mchu@cenhud.com

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

By: */s/ Janet M. Audunson*

Janet. M. Audunson
Assistant General Counsel
National Grid
300 Erie Boulevard West
Syracuse, New York 13202
Tel: (315) 428-3411
Email: janet.audunson@nationalgrid.com

NEW YORK STATE ELECTRIC & GAS CORPORATION and ROCHESTER GAS AND ELECTRIC CORPORATION

By: */s/ Amy Davis*

Amy Davis
Senior Regulatory Counsel
New York State Electric & Gas Corporation and
Rochester Gas and Electric Corporation
Tel: (585) 866-9675
Email: amy.davis@avangrid.com