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' COMMENTS ON DPS STAFF PROPOSAL ON UPDATING DRV AND LSRV FOR VDER COMPENSATION

I. Introduction

The Joint Utilities[1] provide these comments 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, filed on December 11, 2025 (Staff Proposal).[2] The Staff Proposal follows substantial stakeholder process initiated by the Public Service Commission (Commission) in the Marginal Cost of Service (MCOS) Proceeding[3] to evaluate MCOS studies that are used to determine the DRV and LSRV.[4] On August 15, 2024, the Commission issued an order establishing a consistent statewide MCOS methodology and directed the Joint Utilities to file updated MCOS studies with their Distributed System Implementation Plans (DSIPs).[5] Recognizing that additional process was necessary to inform how MCOS should be used to

[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] 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).
3 Case 19-E-0283, *Proceeding on Motion of the Commission to Examine Utilities' Marginal Cost of Service Studies* (MCOS Proceeding), Notice Announcing Marginal Cost Study Stakeholder Forum (issued June 5, 2019).
[4] The Commission has previously determined that MCOS studies would form the basis of compensation for DER. *See* VDER Proceeding, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017) (NEM Transition Order), p. 16.
[5] VDER Proceeding, Order Addressing Marginal Cost of Service Studies (issued August 19, 2024) (2024 MCOS Order), p. 53.

calculate DRV and LSRV, the Commission directed Staff to convene a technical conference to initiate additional engagement.[6] The Joint Utilities participated in this process and filed comments recommending a holistic evaluation of the Value Stack given the rapidly changing dynamics of the electric grid.

The Value Stack compensates distributed energy resources (DERs), including solar and energy storage resources, "for the energy they inject into the utility system" based on "the utility costs they offset,"[7] with the overarching intent of supporting the State's clean energy goals. The Value Stack has contributed to solar and energy storage investment, resulting in a robust DER market that puts the State on track to exceed its 2030 goals. 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 offset utility costs. As the DER market progresses towards greater maturity, the State's approach to compensating DERs should evolve to reflect the avoided costs DERs provide to the system and, as intended by the Commission, provide value, ameliorate (and not exacerbate) affordability concerns, and preserve reliability for all customers.

Accordingly, the Joint Utilities' comments herein recommend updates to the DRV and LSRV operations and performance criteria to better align compensation provided to DER developers with utility distribution system value. Prioritizing this alignment is essential to minimizing unnecessary cost impacts on utility customers, as discussed further below.

More specifically, the Joint Utilities recommend giving individual utilities the option to:

1) Extend DRV and LSRV windows to effectuate actual peak shaving,
2) Adjust DRV and LSRV windows timing so DER operation can remain synchronized with evolving load shapes,
3) Align overall DRV availability and performance with distribution peak shaving to increase value of DERs to the distribution system,
4) Align DRV and LSRV compensation structure with the ability of dispatchable DERs to provide sustained, reliable discharge during appropriate DRV and LSRV windows so DERs have the potential to avoid infrastructure costs,

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[6] *Id.*, p. 51.
[7] *See* VDER Proceeding, Order Regarding Value Stack Compensation (issued April 18, 2019) (2019 Value Stack Compensation Order), p. 4.

5) Offer the opportunity for DRV competition to provide maximum value at the lowest cost to utility customers, and
6) Align LSRV with the ability to defer traditional infrastructure costs to bring LSRV compensation in line with the Commission's intent to compensate projects creating locational value creation.[8]

These recommendations would be enacted in stages with some recommendations being implemented by all utilities on a regular cadence concurrent with the DRV and LSRV rate[9] updates and others being implemented based on individual utilities' billing system requirement timelines. As discussed in more detail below, the timing of implementing specific measures will also vary by utility based on the level and type of DER adoption, with Con Edison implementing some recommendations upon Commission approval and other utilities deferring such implementation.

II. Background

The Value Stack compensation mechanism, adopted in 2017, was initially applicable to solar DERs, among other technologies authorized under Public Service Law sections 66-j and 66-l, and was extended to energy storage in 2018. The intent of the mechanism to provide DERs with "compensation for the value they create,"[10] while also "creating robust and competitive markets for DER that are sustainable over the long-term."[11] Since its adoption, the Value Stack compensation mechanism has successfully contributed to a robust DER market, resulting in the deployment of more than 7.8 GWs of solar[12] and 500 MW of energy storage[13] statewide, and setting the State on track to exceed respective policy targets given that:

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[8] *Id*., p. 17.
[9] Due to differing system needs, Con Edison proposes annual updates whereas the other utilities would use the biennial Distributed System Implementation Plan (DSIP) cycles.
[10] VDER Proceeding, NEM Transition Order, p. 19.
[11] VDER Proceeding, Draft Staff Whitepaper Regarding VDER Compensation for Avoided Distribution Costs (filed July 26, 2018), p. 1.
[12] *See* New York State Energy Research and Development Authority (NYSERDA) Statewide Distributed Solar Projects, *available at* www.nyserda.ny.gov/All-Programs/NY-Sun/Solar-Data-Maps/Statewide-Distributed-Solar-Projects.
[13] *See* NYSERDA Statewide Energy Storage Projects, *available at* www.nyserda.ny.gov/All-Programs/Energy-Storage-Program/Storage-Data-Maps/Statewide-Energy-Storage-Projects.

- Solar deployment across upstate New York has already met 98% of 2030 New York Sun program solar targets;[14]
- 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.[15]

While the rapid growth in DER adoption brings the State closer to achieving clean energy policy targets, highly geographically concentrated growth in bidirectional technologies, such as storage in the downstate region, is adding to infrastructure needs. Further, DERs are additionally encouraged by the Value Stack price signal – which at an earlier stage of market development was understandably open access and unlimited. However, this price signal now needs to (i) align with avoided costs, (*i.e.*, with peak reduction and potential value of infrastructure deferral), and (ii) provide an opportunity to become competitive while still providing project level revenue certainty. Such evolution is critical for utility customers to realize the benefits provided by DERs and for the long-term success of DERs in the clean energy transition. As an example, in Con Edison's service area, nearly $2 billion of DRV compensation to energy storage projects has already been committed for interconnected energy storage projects over the next 10 years; if all projects currently in the Con Edison interconnection queue connect, this would grow to a utility customer cost of over $5 billion in DRV compensation alone over ten years, which is equivalent to approximately 4% increases in Con Edison customer electric bills. Moreover, due to lack of alignment of these DRV costs with avoided costs, the majority of these projects do not deliver commensurate value to utility customers. For example, in the Con Edison service area, half of all energy storage projects operating or with SIR interconnection agreements are concentrated in just 6 of 63 distribution load areas, or less than 10% of the distribution system seemingly driven

[14] Upstate New York has installed 5,636 MW out of 5,943 MW upstate carveout of NY Sun program solar goal. The first 3 GW is outlined in 2016 and 2020 NY-Sun Operating Plans and another 2.9 GW was added to the solar goal in 2022. *See* Case 21-E-0629 *et al.*, *In the Matter of the Advancement of Distributed Solar*, Order Expanding NY-Sun Program (issued April 14, 2022), p. 17.
[15] Case 18-E-0130, *In the Matter of Energy Storage Deployment Program*, Order Establishing Updated Energy Storage Goal and Deployment Policy (issued June 20, 2024), p. 59.

by real estate and interconnection costs, with over 90% of them not providing any distribution peak reduction at area substations.

As proposed by Staff, DRV and LSRV compensation will directly impact energy affordability as these costs are recovered from all utility customers through the VDER Cost Recovery Surcharge, with costs falling mainly on the shoulders of residential customers (e.g., 54% of total DRV and LSRV compensation costs are allocated to residential customers for National Grid). As demonstrated successfully in utilities' non-wires alternatives (NWA) portfolios, DERs in the right place, at the right time, and at the right cost can provide valuable services to the grid that could offset some utility customer costs through deferral of new utility infrastructure in targeted cases. However, the current DRV and LSRV price signals have proven ineffective at realizing DER value.

Additionally, analysis of operational data demonstrates that DERs receiving Value Stack compensation offers value to the electric distribution system significantly below the compensation the DERs receive and do not meaningfully avoid expected distribution system costs. For upstate utilities, current DRV discharge windows, for example, do not consistently align with system planning requirements because they often differ from local system peaks. And downstate, as discussed below, peak DRV and LSRV windows are not sufficiently wide enough to span the full local distribution peak, particularly in areas with relatively flat load shapes. As a result, DRV performance under those circumstances does not lead to any peak reduction. Even with the discharge characteristics proposed by the Joint Utilities, there is a limited quantity of distribution system peak load reduction available.

In the highest DER penetration areas where the load shape is already relatively flat (most notably in New York City), limited incremental peak reduction opportunities are available for new DERs. This is particularly true for energy-limited resources, which provide limited incremental peak reduction, even with widened and optimized DRV windows. Based on Con Edison's analysis, under current rules only 6 percent of VDER energy storage in the queue could provide peak reduction on the distribution system. Further, only a fraction of those DERs that provide peak reduction could actually defer infrastructure capacity expansion projects that are required to meet the quickly growing demand for electric power. For example, the current total estimated deferral value for all infrastructure projects that could be built later due to 4-hour peak reductions from DERs in Con Edison's interconnection queue is less than a third of the total $5 billion cost of DRV payments. In order to maximize the value of utility customer funds already committed to these assets, Con Edison will assess the potential impact and feasibility of leveraging VDER DERs to support transmission security needs.

The significance, and potential benefits, of right-sizing DER compensation in the interest of customer affordability is broad and far reaching. The Value Stack effectively establishes a "price floor" for developers considering participating in peak shaving and infrastructure deferral programs, like NWA, which often include features like performance requirements and associated penalties. Because the Value Stack is not meant to be an incentive program, it is necessary to evolve the framework from an open-access, unlimited eligibility signal to a potential, value-based signal that aligns with the intent of avoided cost[16] delivering benefits to customers.

In sum, using full MCOS value for Value Stack compensation in the current framework results in misalignment between compensation and avoided costs creating undue burden on utility customers. The misalignment is exacerbated in areas of the State with flatter load curves where multiple energy storage resources are necessary to provide a long duration of peak reduction. Those resources are effectively over-compensated when each receive a payment based on the full MCOS.

Staff's Proposal for calculating DRV and LSRV largely follows the previously established methodology but modifies it to set the DRV rate biennially at the weighted average of each utility's full MCOS rather than excluding LSRV areas from the calculation, a feature of previous methodologies known as "de-averaging."[17] Moving away from de-averaging of LSRV areas in calculating DRV values will result in combined DRV and LSRV credits that exceed the system-wide MCOS for the Joint Utilities and more than doubles the DRV for some utilities. Utility customers will ultimately be forced to pay LSRV DERs more than the utility cost to build a traditional infrastructure upgrade, without any assurance of actual infrastructure deferral. The Joint Utilities, in prior comments,[18] have urged the Commission to recognize the true value DERs provide, and the Commission's intent, is the value of cost avoidance through deferral of

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[16] *See* VDER Proceeding, Order Regarding Value Stack Compensation, p. 9.
[17] *See* VDER Proceeding, Staff Proposal, p.4.

specific infrastructure projects. Using full MCOS value for compensation does not allow other customers to share in any of the potential avoided costs from DERs.

These comments focus on aligning DRV and LSRV compensation with distribution benefits. The Joint Utilities also recognize that some of these proposed changes will take time to implement and will require changes to utility billing systems. However, the improvement in the DRV and LSRV framework is necessary to capture system benefits.

III. Joint Utilities' Proposal

1. Extend DRV and LSRV windows to effectuate actual peak shaving

The Joint Utilities are observing that load curves in certain parts of the distribution system across the State are becoming flatter, particularly downstate. Therefore, a simple 4-hour DRV window no longer suffices as an indication of peak reduction potential. Consequently, DRV windows with different durations will be required to reduce the distribution peak (see appended Figure 1).

As a result, the Joint Utilities propose that each utility have the option to offer 6- and 8-hour DRV and LSRV windows to complement the current 4- or 5- hour DRV and LSRV windows. These wider windows will have defined MW thresholds and will increase the number of DERs that are able to actually reduce the distribution peak and thereby increase their value to the distribution system.[19] For example, if DRV windows in Con Edison service area were expanded to 6 and 8 hours for energy storage projects that are not yet executed interconnection agreements, 17% of the capacity of all energy storage projects that are in the queue would result in distribution peak shaving, compared to 6% with the existing 4-hour DRV window.[20]

As before, DRV and LSRV components of the Value Stack will be calculated over the relevant window. If the DRV and LSRV windows are extended, DERs must discharge consistently over the entire window to receive full payment, or can discharge at a lower rate and the DRV and LSRV payment will be prorated accordingly (see appended Figure 2). DRV and

[19] Upon Commission direction, Con Edison intends to adopt this approach immediately to meet current system conditions, other utilities may do the same when system needs require it.

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

LSRV rates and window lengths would still be locked in for ten years to provide certainty to developers.

While changing the discharge period to appropriate durations needed for peak reduction will require adjustments to energy storage resources, energy storage systems are highly flexible in design and operation, and can be reconfigured to meet the wider discharge windows. Continuing to compensate based on a MCOS-derived DRV that represents the cost of a 24 hour resource, to energy-limited resources that do not effectively reduce peak could result in compensation well in excess of the value to customers. For example, if an 8-hour resource is needed to reduce a distribution peak and the utility must stagger two different 4-hour storage resources to achieve peak reduction, and both resources were compensated based on an MCOS-derived DRV, then customers would effectively be paying up to double the unit cost embedded in MCOS for a given MW of peak reduction. And as described above based on the design of DRV as a longer term price signal, only a portion of resources that reduce the peak result in actual utility infrastructure deferral. In line with the Commission's intent to compensate resources commensurate with their benefit to the grid, the DRV distribution peak reduction and performance should form the basis for the compensation design.

In addition to the existing LSRV MW capacity, utilities would have the option to state the peak shaving capacity for DRV that is available by distribution load area on their VDER Credit Statements. This would include the available MW and the duration and time of the new DRV window. DERs will be assigned the applicable DRV and LSRV discharge window in their interconnection agreement. Utilities would have the option to remove from these statements load areas where DERs can no longer assist in peak reduction.

2. **Adjust DRV and LSRV windows timing so DER operation can remain synchronized with evolving load shapes**

Currently, DRV and LSRV windows lack flexibility to evolve with the changing grid; the window time periods are static and locked in for 10 years. For most upstate utilities the windows are fixed at the hour beginning 2:00 PM through the hour beginning 6:00 PM; for Con Edison there are four distinct four-hour time windows assigned depending on distribution load area based on the local peak in that area.[21] Shifts in customer behavior due to adoption of new technologies, such as heat pumps, and electric vehicles have already resulted in changing load patterns, which will continue to evolve as adoption of these new technologies increases. As an example, in Con Edison's service area, nearly half of the networks have changed peak hours over the last five years. To allow resource performance under the Value Stack to best align with grid needs over time, DRV and LSRV window timing should evolve with changing grid needs.

Providing utilities flexibility to set and revise window time periods for DRV and LSRV will increase the operational benefits projects can deliver. In this proposal the time period refers to which hours of the day a given resource should dispatch. The duration length of the window would be set based on the process laid out earlier and would not change across the 10-year lock period to provide certainty to the DER market.

The Joint Utilities propose the following for new projects: 1) allow utilities the ability to assign differing windows by distribution load area or region based on system needs for both dispatchable and non-dispatchable DERs upon Eligibility Date; [22] 2) provide utilities the ability to shift window time periods assigned to projects on a periodic basis depending on load characteristics and grid need only for dispatchable DERs;[23] and 3) permit utilities to structure window time periods and LSRV event calls to cover winter peaking networks and weekend contingencies as needed.

Utilities are increasingly observing load pattern differences by distribution load areas, suggesting that VDER resources could be better utilized by assigning projects to different performance windows based on load areas. As appended Figure 3 demonstrates, National Grid's substations have local peaks that differ from both system peaks and each other. Aligning performance windows with local peaks, rather than requiring all networks to be assigned to a single peak, will increase grid, and therefore customer value. Diversity in local load area peaks influenced the Commission's decision to grant Con Edison the ability to create multiple

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[21] For all Joint Utilities, DRV hours are on non-holiday weekdays from June 24 to September 15. Con Edison has four distinct DRV windows corresponding to the Commercial Service Relief Program (CSRP) call windows to reflect differences across their service area.
[22] Eligibility Date is the date at which the customer satisfies at least 25% of its interconnection cost responsibility in accordance with the Standard Interconnection Requirements (SIRs) or executes the SIR Contract if no such interconnection cost responsibility is required.
[23] Con Edison proposes annual updates; the other utilities would use the biennial DSIP cycle to update window time periods.

windows.[24] Given the recent experience of National Grid and the other utilities, it is appropriate to provide this flexibility to utilities statewide.

Providing utilities the ability to adjust windows on an annual or biannual basis will allow utilities to keep dispatchable DER performance synchronized with grid needs as load shapes change. Comparing National Grid's top ten peak hours between 2016 and 2025, appended Figure 4 shows that National Grid's service area has seen peaks shift later into the evening since the Value Stack compensation began in 2017. More nimble DRV and LSRV windows will enable utilities to maximize the value of DERs that utility customers are compensating.

In addition, allowing periodic window adjustments to include winter and weekend events will allow performance windows to evolve with distribution grid needs. Appended Figure 5 presents an example of a substation in National Grid's service area that is already peaking during the winter.[25] Likewise, Con Edison forecasts suggest that such winter peaking load areas will emerge within the next decade, with continued building electrification, potentially within the timespan of VDER rate lock-ins happening today. Furthermore, weekend peak loads will increase in magnitude, approaching weekday peak loads in some local load areas.[26]

For existing DERs, the applicability of flexible peak-shaving windows should vary by resource type. Existing non-dispatchable DERs that have limited ability to modify operations, such as solar and wind, should retain the DRV and LSRV windows that were locked in on their respective Eligibility Dates for the entire 10-year term. For existing dispatchable DERs, utilities should have discretion to move (but not extend) peak shaving windows because these DERs can adjust dispatch schedule without affecting the project's ability to satisfy such windows.

3. **Align overall DRV availability and performance with distribution peak shaving to increase value of DERs to the distribution system**

[24] The initial window sets by utility were established based on a review of recent peak load hours for each utility. *See* VDER Proceeding, 2019 Value Stack Compensation Order, p. 20.

[25] National Grid's historic load data show independent substation peaks that vary from 2pm-10pm in the Summer and Winter. However, additional and more robust analysis is required to determine exact system needs for performance windows through future studies to better understand potential impacts on the electric power system.

[26] For example, events called in one substation in Con Edison's service territory in 2025 showed that peak weekend loads were about 96 percent of peak weekday loads.

The Commission's original intent in creating the distribution system related components of the Value Stack was to create value streams so that "as DER providers work to maximize compensation, they will also maximize benefits to the system."[27] DRV was envisioned as a value calculated "based on the distribution costs offset by injections"[28] recognizing that assets that are eligible for DRV should at least provide the potential for cost avoidance which can only be achieved by peak reduction.

The current DRV structure allows DERs to receive compensation everywhere on the distribution system, without consideration of the DER's actual ability to reduce the local distribution peak (which is the main distribution cost driver behind load growth-driven infrastructure upgrades). The vast majority of DERs discharging through narrow windows when peaks are getting longer and flatter result in diminished peak reduction and could trigger new system needs if charging creates new (nighttime) peaks greater than prior daytime peaks. Therefore, these DERs cannot contribute to the reduction of distribution investments, and in some cases can drive the need for new infrastructure to support charging of storage resources. For example, load curves at several substations in Con Edison's service territory are sufficiently flat, such that new DERs operating during a pre-defined four-hour DRV window[29] do not provide further peak shaving. The shoulder areas outside the four-hour period would set the new peak demand for the substation while the overnight charging for energy storage in some of those areas would drive load above the afternoon peak. Appended Figure 6 provides an example load shape where injection from energy storage over a narrow window of a broader peak does not contribute to the overall peak reduction and charging creates a new, higher peak.

To better align distribution system value with compensation provided by DRV, utilities should have the option to screen new dispatchable projects to determine access to DRV compensation under the following criteria: (1) the project is sited in an area of the distribution system where the load shape is not flat and there is potential for the DER to lower the peak, (2) the project must dispatch during the full duration that results in reduced in local distribution peak, and (3) net import demand for bidirectional technologies do not set new peaks .

[27] VDER Proceeding, NEM Transition Order, p. 111.
[28] VDER Proceeding, 2019 Value Stack Compensation Order, p. 4.
[29] In some cases, extending windows to six or eight hours may provide further opportunity for peak shaving.

If utilities were authorized to implement these eligibility criteria, they would identify locations on the distribution system in their VDER Credit Statements where incremental peak shaving capability is still available, inclusive of the associated DRV window duration needed to achieve peak shaving (e.g., 4-hour, 6-hour, or 8-hour peak shaving),thereby providing a clear signal to the DER market. In locations where the load shape is sufficiently flat such that incremental DER discharge will not result in reduction of the local distribution peak, there would be no opportunity for DERs to receive compensation for the DRV component of the Value Stack. In areas where peak shaving capacity is limited, utilities may offer capacity available in each "tier" (see recommendation #5 below).

The Joint Utilities are proposing a move from an open access, unlimited quantity eligibility framework to one where the basis of compensation is tied to the potential for distribution costs offsets.

Ultimately, the process described above will have the effect of shifting DER deployment to areas where value to the grid, and therefore customers, is greatest. This brings Value Stack compensation more in line with the objective, noted above, for "creating robust and competitive markets for DER that are sustainable over the long-term"[30] while providing price signals that align Value Stack compensation to projects with the potential to "maximize benefits to the system."[31]

The Joint Utilities' proposal balances sustainable market growth with customer bill impacts by maintaining the DRV 10-year lock-in period with the potential for DERs to earn up to the full DRV price proposed in Staff's Proposal. Together, these can create benefits to the grid while also seeking to minimize negative impacts to affordability.

4. <u>Align DRV and LSRV compensation structure with the ability of dispatchable DERs to provide sustained, reliable discharge during appropriate DRV and LSRV windows so DERs have the potential to avoid infrastructure costs</u>

Currently, dispatchable DERs choose when to inject into the utility's distribution system and may seek to optimize the sometimes conflicting price signals amongst different components of the Value Stack. Operational data suggest that some dispatchable DERs reduce performance

[30] *Supra* note 11
[31] *Supra* note 27.

during some of the hours targeted by the DRV and LSRV. For example, a dispatchable DER might curtail on a hot, summer day during DRV hours in order to perform during hours that may be related to the Value Stack's Installed Capacity (ICAP) Alternative 3 credit. This behavior undermines the value that customers receive if the resources are not performing at the highest levels during days of highest demand. To correct for this misalignment, the Joint Utilities propose, for new dispatchable DERs only, that each utility should have the option to calculate DRV compensation for a given day based on the lowest hourly injection during the applicable DRV window of these DERs. For example, a DER in a 4-hour DRV window would need to export at a given capacity level across all 4 hours in the window to receive compensation for that level of capacity; the same would apply for DERs in the 6- and 8-hour tiers.

DRV price signals are calculated on a volumetric basis based on performance over approximately 60 days and the LSRV is based on performance on ten days. In contrast, the Value Stack's Installed Capacity (ICAP) Alternative 3 credit for dispatchable DERs, provided over the full year, is determined exclusively based on the DER's injection during the previous year's single system peak hour. Under this current price signal framework, a dispatchable resource is encouraged to "chase" the anticipated peak hour on anticipated ICAP peak days in order to not miss capturing the associated value since it an all or nothing proposition. At the same time, the volumetric nature of the DRV price signal does not materially reduce compensation if DERs reduce output during local peak distribution hours. If DRV and ICAP windows differ (see appended Figure 7), dispatchable DERs reasonably shift focus to operating during possible NYISO peak load hours to capture the ICAP component of the Value Stack.[32] When a resource does not perform for these few days during their DRV and LSRV windows, it renders the utility incapable of relying on DERs for potential distribution system value considering that the curtailment may occur on the highest demand days when the resources are most needed.

For existing DERs and new non-dispatchable DERs, such as solar or wind, the DRV and LSRV performance calculation methodology described in this section would remain unchanged.

[32] Under VDER Phase Two Alternative 3, monthly credits are a function of 1) the resource's net injection during the ICAP Market Peak Hour of the previous year and 2) NYISO market clearing prices for a given month. *See, e.g.*, Consolidated Edison Company of New York, Inc., Electric Tariff Schedule, P.S.C. No. 10, Leaf 253.2.2, Revision 1.

5. Offer the opportunity for DER competition to provide maximum value at the lowest cost to utility customers

To deliver DER value at the lowest cost to utility customers and efficiently allocate peak shaving capacity, utilities should have the option to implement and offer competitive solicitations for DRV allocations in parts of the distribution systems where incremental peak shaving capacity is limited (see proposal #3 above), as seen in certain parts of Con Edison's service area today.

Specifically, during the interconnection application process, DER developers will have the option to submit an application with a proposed capacity and for a DRV rate that may be lower than the DRV ceiling set according to Staff's Proposal and the Joint Utilities' proposal outlined above. Each load area peak shaving tier (*i.e.,* 4-, 6-, 8-hours) will be considered a separate "product" and bids may be submitted for capacity across all peak shaving "products". Utilities would sort the applications in the queue based on the submitted DRV offer, allocating DRV peak reduction capacity to projects with the lowest cost to utility customers for each peak shaving product and developers can make choices for utility study and submit their deposit.

The Joint Utilities recognize that the above framework will require amendments to how interconnection applications are processed (*i.e.,* transition to a "batched" review of applications received over a period of time). Further details can be described in a separate filing.

6. Align LSRV with ability to defer traditional infrastructure costs to bring LSRV compensation in line with the Commission's intent to compensate projects for locational value creation

The Commission established LSRV compensation to provide "incentives for distributed generation developers and owners to design and operate their projects in ways that meet utility needs and will ensure that appropriate compensation is offered to projects that help offset costs in constrained areas of the distribution system."[33] Staff Proposal recommends adoption of a single LSRV rate for each utility that is applicable to areas in which a utility's costs are significantly higher than system-wide costs.

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[33] VDER Proceeding, 2019 Value Stack Compensation Order, p. 19.

To align LSRV compensation with actual distribution system needs and the Commission's intent to ensure LSRV is provided to projects that help offset costs in constrained areas of the distribution system, the Joint Utilities should have the ability to screen LSRV areas identified by Staff's proposed methodology. This screening determines if planned infrastructure investments can still be deferred. Specifically, for the load relief required for deferral of infrastructure upgrades on their distribution systems, utilities will have the option to assess the capacity required, the applicable time windows, and seasonality requirements (*e.g.,* which time of year is peak shaving needed). Furthermore, utilities should identify the date by which the peak shaving must occur to avoid traditional infrastructure upgrades or the launch of an NWA solicitation. New DER projects will not be eligible for LSRV in areas where the utility has already started either a traditional infrastructure project or NWA solicitation even if that area was previously identified as an LSRV area because the infrastructure costs can no longer be avoided. Once LSRV areas have been established, utilities will have the option to set a deadline for DERs to become operational based on the local system needs; if the project deadline for operation is missed, the DERs would no longer be eligible for the LSRV compensation. Utilities will continue to update the peak shaving MW capacity for deferral at each area substation on the VDER Credit Statement as project capacity is either added or removed from the utility queue based on eligibility. To have more certainty that these DER projects will proceed to construction and offer reliable peak reduction, the Joint Utilities propose that eligibility for LSRV compensation be locked in at the time the customer submits a full deposit instead of the current 25% payment deposit trigger, as well as require LSRV DERs to interconnect at the same reliability standard as the local system they are interconnecting to, similar to the treatment of DERs participating in NWA portfolios.

Finally, the Joint Utilities propose to remove the minimum LSRV call requirement. Since there is evidence of DERs being called upon simply to meet the call requirement as opposed to addressing location specific load relief, the number of times a resource is called should be at the discretion of the utility. This is consistent with the Staff Proposal that "LSRV resources should exhibit the level of reliability and dispatchability that the utilities' planning engineers require to provide a capacity solution in those highest cost areas."[34] These requirements for receiving LSRV compensation complement those described above that apply to both DRV and LSRV.

IV. Answers to questions in the Staff Proposal

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?

Yes, the two-year cadence for updating the LSRV rate is long enough for developers to plan and reach that milestone stage. The Joint Utilities expect the Commission to authorize utilities to implement updated MCOS results based on the approved state-wide methodology. Based on analysis of 360 energy storage projects in Con Edison's interconnection queue, the average time to reach the 25% interconnection downpayment stage is approximately one year from the date the application is submitted. Therefore, there is no reason to extend prior LSRV rates beyond the proposed two-year cadence as the new LSRV rates will reflect the then applicable system needs.

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?

Each utility already reports on interconnected DER and the cost recovery of VDER credits in their Value of Distributed Energy Resources Cost Recovery Statements.

In addition, the Joint Utilities propose to report both annual expenditures and the capacity (MW) of DRV and LSRV resources, which will enable parties to calculate the unit cost in $/MW for each.

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

These proposals will not impact the planning process as VDER resources are included in load forecasts (either fully when operational or discounted when in the interconnection queue) so

[34] VDER Proceeding, Staff Proposal, p. 8.

they are being captured in the Coordinated Grid Planning Process (CGPP) and 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?

Bulk transmission projects regulated by the Federal Energy Regulatory Commission (FERC) should not be included in the weighted average marginal cost by substation, nor the calculation of the DRV and LSRV rates. Non-bulk (local) transmission projects should be allocated to the relevant substations based on individual utility analyses and engineering judgement of the amount of substation load expected to be supplied by the system-wide transmission project. Utilities that require updated DRV and LSRV calculations based on this allocation filed those updates contemporaneously with these joint comments.

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

The Joint Utilities believe the existing VDER tariffs and statements, which identify LSRV zones and remaining DER capacity needed to defer investments, are sufficient to implement the Staff Proposal. As a result, the utilities are not filing draft tariffs at this time. However, based on the Joint Utilities' proposal in these comments with potential changes to both the DRV and LSRV windows and other provisions, changes to both the tariff and VDER statements would be required, including revised applicable DRV and LSRV windows.

Tariff: The following information should ***continue*** to be listed in the tariff

- Explanation of how the LSRV credit will be calculated: *e.g.,* by multiplying the customer-generator's net injection during the established hours by the applicable LSRV component rate. (LSRV credits are calculated based on lowest net hourly injection in the applicable call period each billing period)
- Explanation that the applicable LSRV compensation rate and compensation hours for non-dispatchable resources will be set at the time: *e.g.,* based on the terms at the time the

interconnecting customer pays at least 25 percent of its interconnection cost or executes the interconnection agreement, and will remain fixed for 10 years. For dispatchable resources, the LSRV compensation rate will also be determined and fixed for 10 years in the same manner, but the compensation hours may be updated annually or biannually.

- Criteria for activating LSRV: *e.g.,* at least 21 hours of notice before each LSRV Event.
- Criteria for opting into DLM programs in lieu of DRV and LSRV.
- Metering and Communications requirements.

Statement: The following information will continue to be listed in the Statement of VDER Value Stack Credit Statement:

- Location and MWs available in each LSRV zone
- Applicable performance windows for each LSRV zone
- LSRV Rates

Interconnection Agreement

- This already covers installation requirements for all DER including resources eligible for the Value Stack and LSRV and DRV components, if applicable.

Other items in Staff's Appendix E

These are not appropriate for the tariff, but could be included in future agreements with Value Stack resources:

- Performance testing under test events
- Penalties for Failure to Perform
- Early Termination penalties
- Force Majeure Clauses

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 2025 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.

No, Con Edison and O&R's MCOS studies develop per-kW marginal cost estimates based on the load carrying capacity of the equipment installed to meet load growth under applicable contingency conditions. Therefore, when developing the ten-year levelized value, the net present value calculation is applied to the $/kW of annualized investment cost.

7. National Grid included transmission projects in their MCOS study. Page 44 of the August 2025 MCOS order requires that 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?

Contemporaneously with these comments, National Grid filed updated workpapers using Staff's methodology, as provided in Staff's workpapers updated on March 5, 2026. National Grid's update now clearly delineates the bulk federal transmission projects from the local transmission projects. In the file, National Grid allocated local transmission projects to underlying substations as described in National Grid's filing letter. National Grid calculated a marginal cost rate for the bulk transmission projects but did not include the results in the calculation of DRV or LSRV retail rates. Utilities that also require updated transmission project allocations in their workpapers filed those updates concurrent with these joint comments as well.

V. Conclusion

Given the rapid growth in DERs, driven in large part from the adoption of the Value Stack compensation mechanism, the Joint Utilities hereby recommend updates to the DRV and LSRV framework, operations, and performance criteria to better align compensation with distribution system value, and encourage the Commission's consideration of the proposed updates. These updates are supportive of the focus on energy affordability and stress the need to avoid significant and unnecessary cost impacts to customers.

Dated: March 16, 2026

Respectfully submitted,

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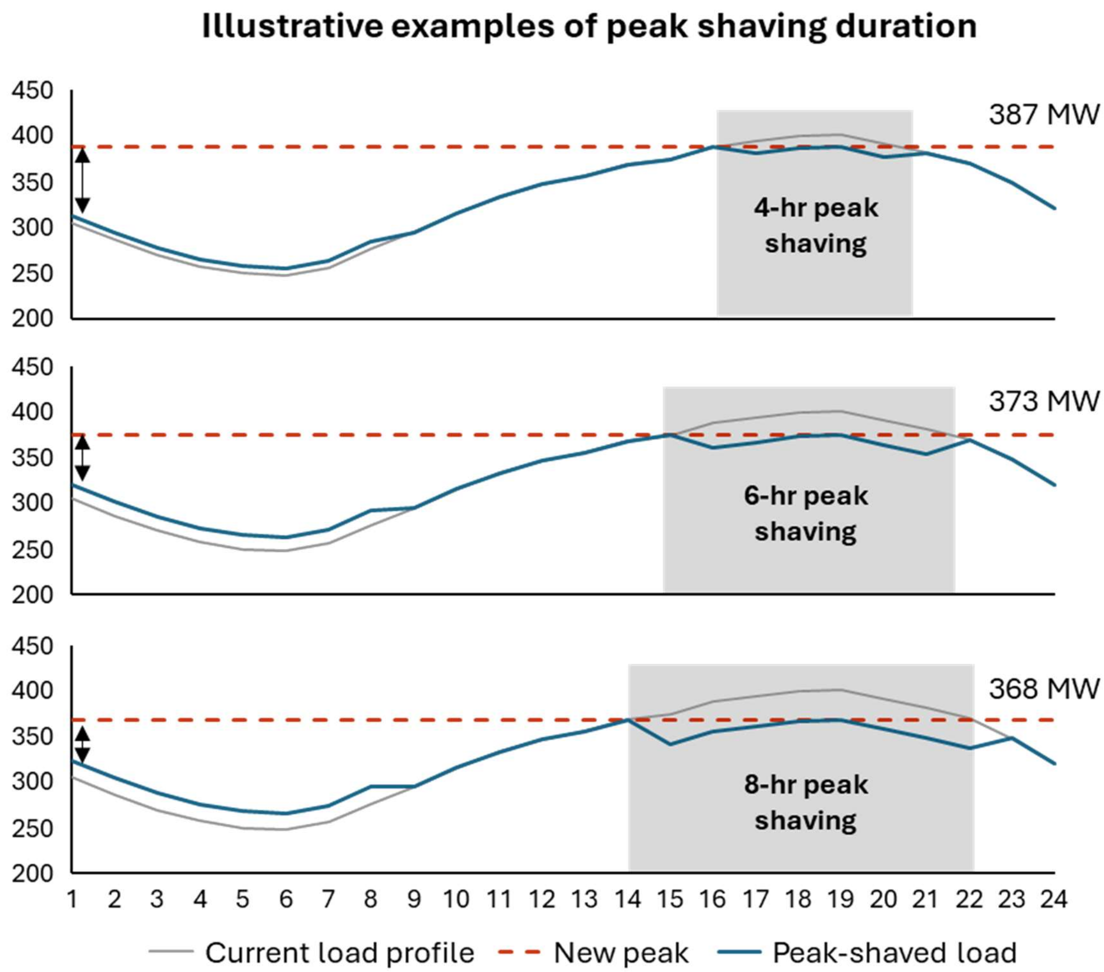
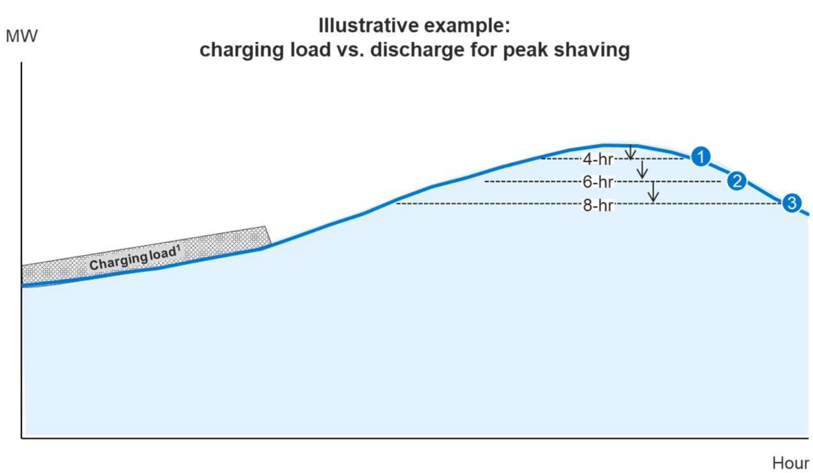
VI. Figures

Figure 1. In some load areas, longer DRV and LSRV windows will be required to reduce distribution peaks.



Figures 2. DRV and LSRV compensation will be calculated over the entire DRV window, so DERs can discharge consistently over the entire window to receive full payment, or can discharge at a lower rate and the DRV and LSRV payment will be prorated accordingly. (Con Edison proposal)

DER exporting duration	Peak shaving "tier" ceiling		
	4-hr peak shaving	6-hr peak shaving	8-hr peak shaving
4 hours	100%	66%	50%
6 hours	100%	100%	75%
8 hours	100%	100%	100%



DRV eligibility

1 → 4-hour peak shaving capacity
2 → 6-hour peak shaving capacity
3 → 8-hour peak shaving capacity

DRV performance payment

Assessed based on discharge of DER during entire peak shaving window

Example performance and annual DRV payout for 5 MW nameplate / 20 MWh battery

Full DRV	Payment if discharge at full nameplate MW for full window	Pro-rated payment if discharge lower than nameplate to cover full window
4-Hr	$1,260k (100%)	$1,260k (100%)
6-Hr	$1,260k (100%)	$832k (66%)
8-Hr	$1,260k (100%)	$630k (50%)

Figure 3. National Grid's substations have local peaks that differ from both system peaks and each other.

Peak Hour Across NYISO Zone C Substations on 7/5/2025

NYISO Zone C peak hour on 7/5/2025 is 19:00
Substations within Zone C on 7/5/2025 peak hours fall between 17:00-22:00

Substation	Peak Hour
NIMO	20:00
NYISO Zone C	19:00
Substation 1	22:00
Substation 2	20:00
Substation 3	19:00
Substation 4	21:00
Substation 5	21:00
Substation 6	17:00

National Grid

Figure 4. Comparing National Grid's Top Ten Peak Hours between 2016 and 2025 shows that National Grid's territory has seen peaks shift later into the evening since the Value Stack began in 2017.

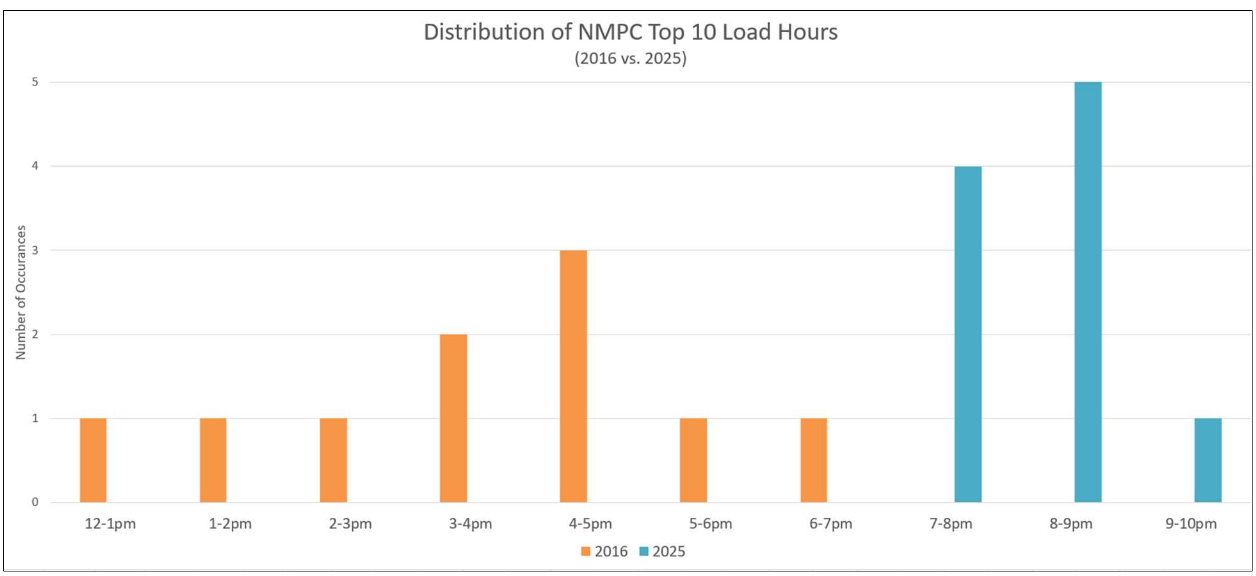


Figure 5. Example of a substation in National Grid's territories that is already peaking during the winter

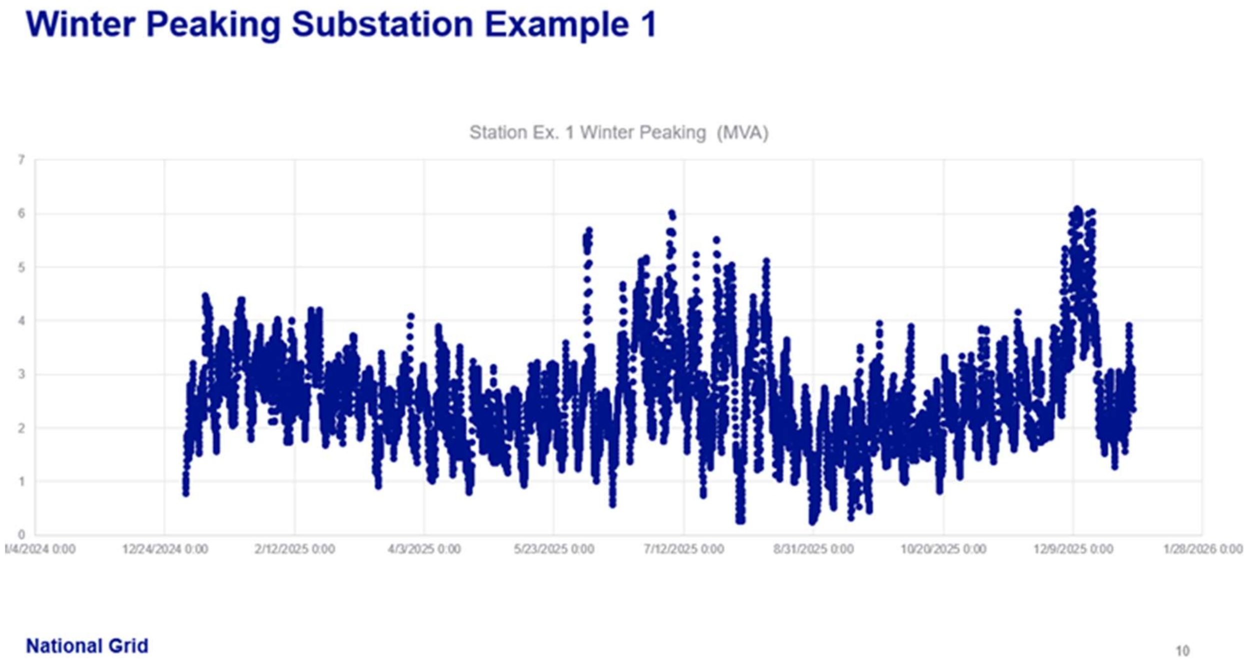


Figure 6. An example load shape where injection from energy storage over a narrow window of a broader peak does not contribute to the overall peak reduction, and charging creates a new, higher peak.

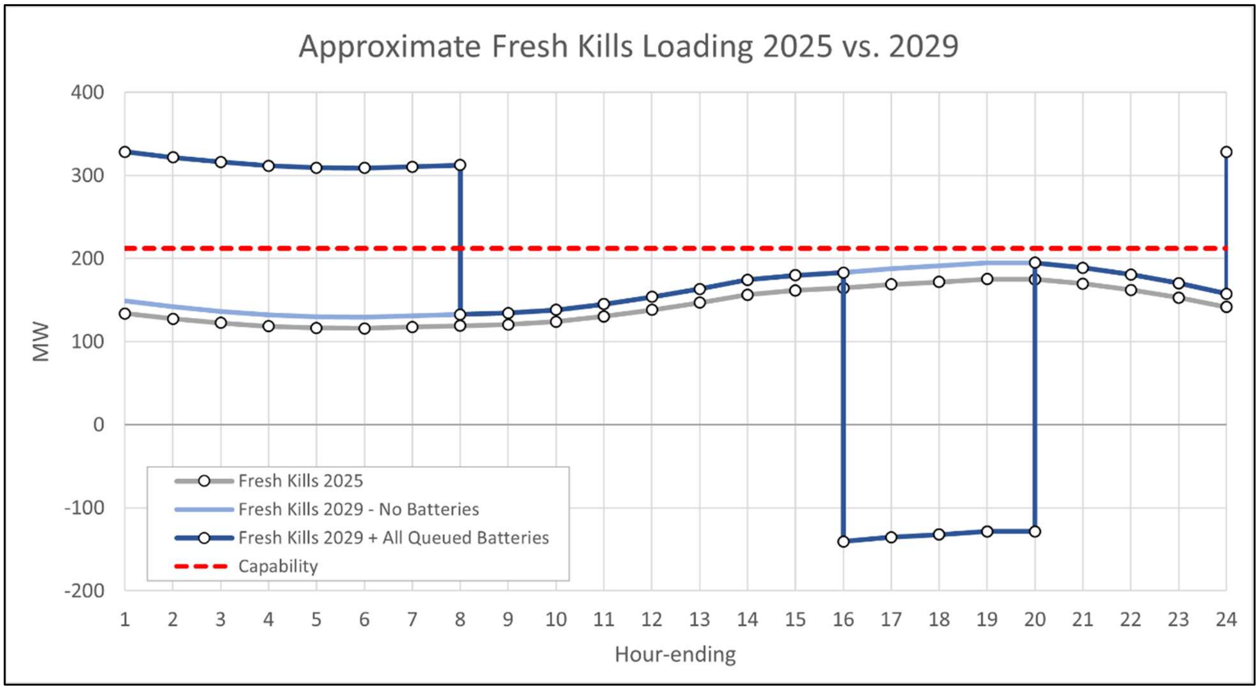
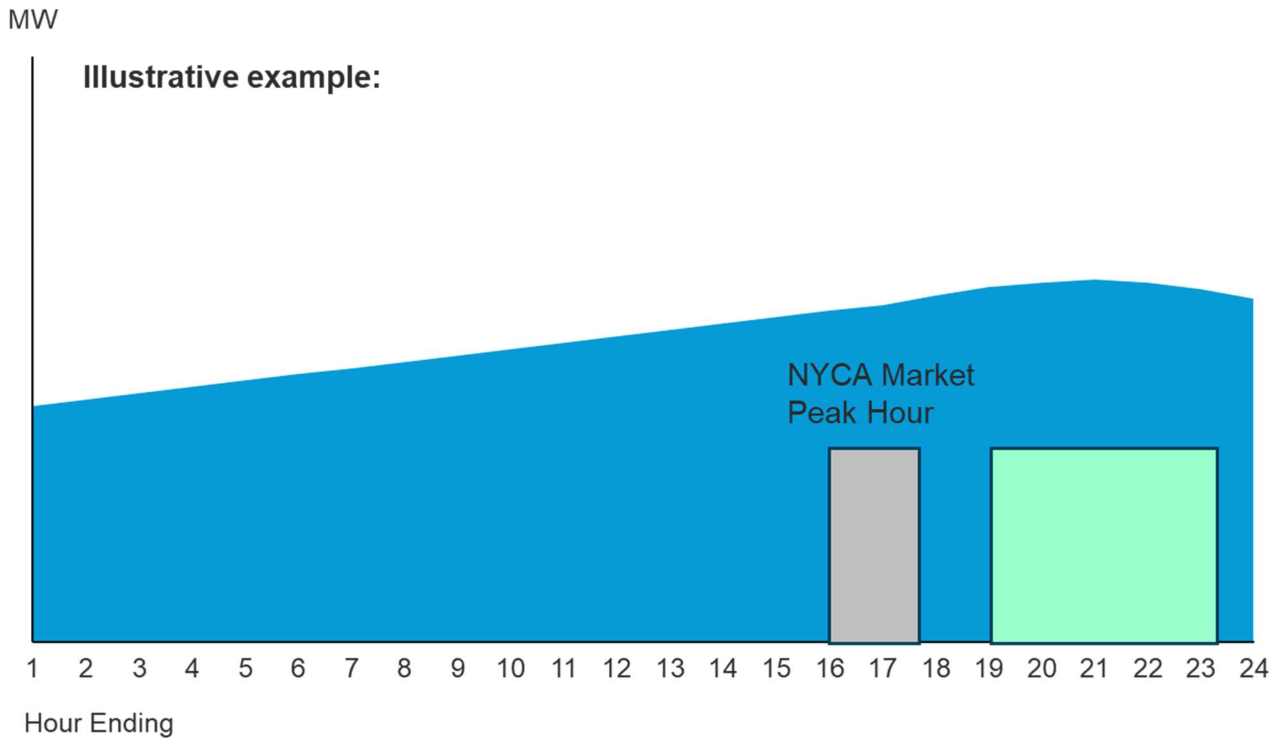
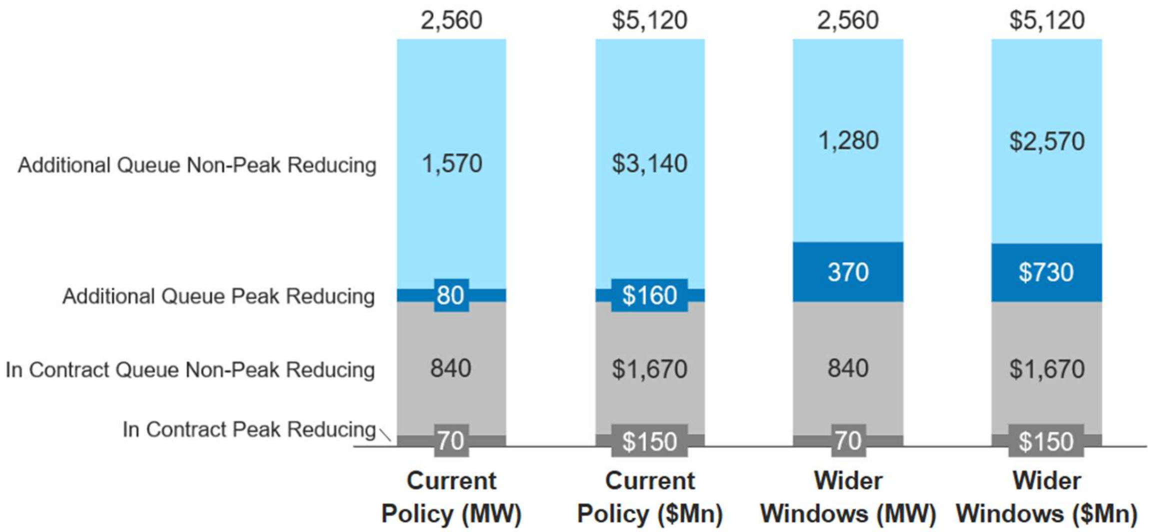


Figure 7. If DRV and ICAP windows differ, dispatchable DERs will reasonably shift focus away from DRV or LSRV hours to operate during possible NYISO peak load hours seeking to capture the ICAP component of the Value Stack.



As shown in the chart below, the implementation of the JU proposal for wider peak shaving windows results in a meaningful increase in the share of DERs in the interconnection queue that can offer distribution grid value



Notes: 1) Wider Windows (MW) was evaluated by keeping in-contract energy storage to a 4hr dispatch window and shifting additional queued energy storage projects' peak reduction potential to 4-6-8-hr dispatch window.
2) Subject to change based on queue analysis