Ascend Analytics
MARKET INSIGHTS

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Can VDER Storage Match the Success of VDER Solar?

New York's Value of Distributed Energy Resources (VDER) program has reliably generated revenue for solar developers for years. Optimizing revenue for standalone battery energy storage systems (BESS), however, presents a different challenge: unlike solar, a battery's revenue depends on when it discharges and charges, which involves navigating a maze of utility-specific costs. For solar developers considering storage in New York, understanding this distinction matters: the payoff for storage can exceed what solar earns today, though only for projects that get the dispatch strategy right.

In a recent webinar hosted by the [New York Solar Energy Industries Association (NYSEIA)](), Caroline Zechter, Director of Community Solar and Peter Wise, Senior Energy Analyst at Ascend Analytics discuss how storage monetizes the [VDER value stack]() differently than solar, why capacity revenue carries the most risk and the most reward, how variation in utility charging costs vary influence where projects get built, and what regulatory shifts could reshape the program in the years ahead.

Key Takeaways

- Storage revenue under VDER depends entirely on charge and discharge timing. In downstate New York, a 5 MW, 4-hour battery can generate net revenue that exceeds an equivalent solar project's revenue by more than 40%, and can nearly double what the same battery would earn selling into the wholesale electricity market alone.

- Installed Capacity (ICAP) compensation, paid under Alternative 3, is both the largest and riskiest piece of the VDER value stack. It carries price risk tied to wholesale capacity auction dynamics and capture risk tied to hitting a single, uncertain peak load hour each year.

- Demand Reduction Value (DRV) functions as VDER storage's most bankable revenue stream: it's fixed for 10 years, tied to defined summer weekday windows, creating revenue certainty on top of which financiers can grant more favorable terms for debt. Proposed New York Department of Public Service (DPS) rate updates released in December 2025 would raise DRV values for most utilities, and PSEG Long Island (PSEG) has already implemented a 33% increase.

- Charging costs vary sharply by utility and can make or break a project's economics. New York State Electric & Gas's (NYSEG) contract demand charge runs roughly 10 times National Grid's. Costs in NYSEG are exacerbated by a shorter overnight window free of as-used demand charges, impairing projects from more fully optimizing an overnight trickle charging strategy. Historically, full capture of both DRV and ICAP Alt 3 has been possible as New York's peak load hour has fallen within common DRV windows for the past decade. As peak load hour occurrences shift later in the day misaligning with existing DRV windows, operators will need to pursue discharge into peak load hours outside of DRV windows. Day-ahead load forecasts can ensure a four-hour battery can capture ICAP with high confidence and only minor, if any, sacrifice to DRV revenue.

- Longer term, tension is building between VDER's current summer-peaking design and the New York Independent System Operator's (NYISO) forecasted shift to winter peaking by 2040. Regulators may eventually need to adjust the ICAP peak-hour definition, add winter DRV windows, lengthen DRV windows, or shift them later in the day to keep the program aligned with grid needs.

Why is Storage in VDER Attractive Amidst its Complexity?

Solar's VDER revenue is essentially locked in once a project is built: production times the value stack components determine the payout, and there's little else a developer can do to influence it.

On the contrary, a battery's margin depends on sophisticated operation of the asset – knowing when to charge and discharge. The timing of charge and discharge decisions interacts with capture of energy prices, DRV, capacity payments, and the utility costs incurred to charge in the first place.

Getting the timing right can produce significant value for storage relative to solar. As illustrated in **Figure 1**, net revenue for the year 2030 reaches $2.4 million under current DRV rates and $2.6 million if proposed rates are finalized, compared with $1.7 million for an equivalent 5MW solar project versus a 5 MW, 4-hour battery in Consolidated Edison's (ConEd) Zone J. Higher revenues are driven by how storage can monetize its flexibility by ensuring greater discharge into the DRV window and by providing greater capacity services under capacity alternative 3.

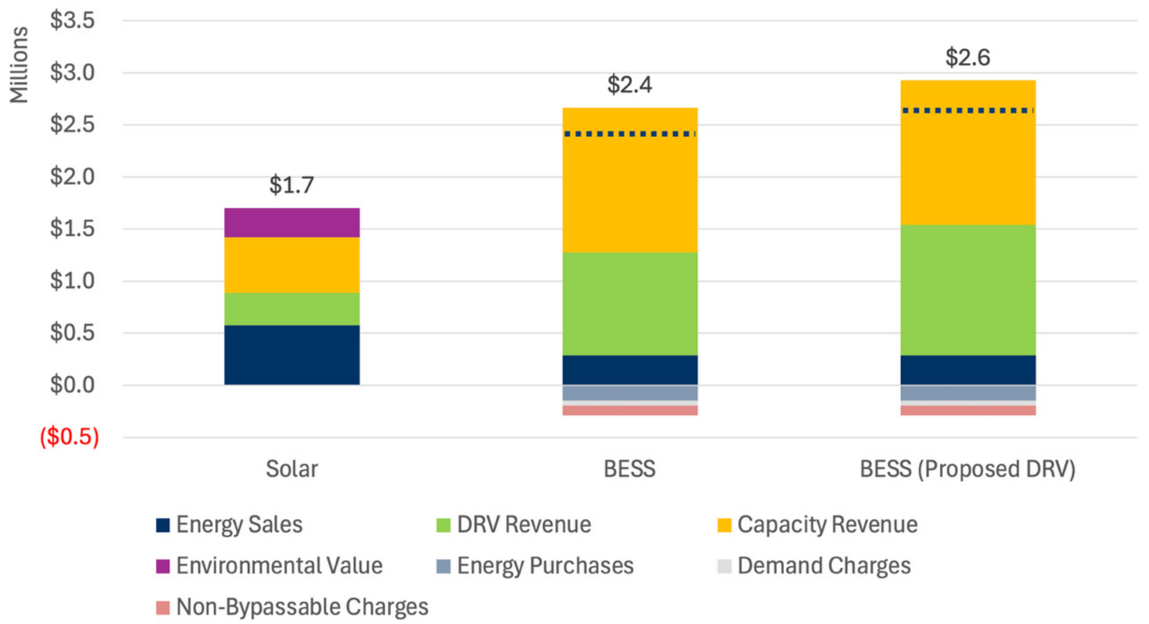

Figure 1. Solar and BESS Gross Margins ($MM), ConEd Zone J - 2030

Similar dynamics apply in upstate New York. In National Grid's Zone F, for example, storage revenue roughly matches solar today, at $1.1 million versus $1.2 million, and would climb well past it, to $1.9 million, under proposed DRV values.

What Makes ICAP Alt 3 the Riskiest and Most Valuable Piece of the Stack

Unlike solar and hybrid projects, which can choose among three capacity compensation alternatives, standalone storage is required to take Alternative 3, which produces a payment based on a project's output during a single system peak hour of the previous year.

That structure creates two distinct types of risk – pricing and performance risk. First, because ICAP compensation is based on wholesale capacity auction prices, projects face price risk in the value of payments. New York's capacity market prices are generally binary, clearing near the cost of keeping existing plants online when supply is adequate, or near the cost of building new generation when it is not. Programs such as the state's Index Storage Credit subsidize new battery entry, allowing subsidized capacity to act as a price taker that suppresses capacity prices. That dynamic is what makes pricing risk hard to pin down: subsidized entry could keep pace with load growth and hold prices near a floor (cost of keeping existing entry online), or lag behind it and push prices toward a ceiling (Net Cost of New Entry -- Net CONE). Ascend's capacity forecast models the expected value of capacity prices within a band of uncertainty between floor and ceiling conditions.

Capture risk is the second piece: miss the single peak hour, and a project forfeits capacity revenue for the entire year. The good news is that this hour has fallen between 4 and 7 p.m. in the past decade, allowing for predictable capture of both capacity and DRV revenue components. In the future, the peak load hour is expected to fall later in the day, occurring near the end or after common DRV window hours. This misalignment will incent operators to discharge into likely peak hours outside the DRV window to ensure capacity capture. Doing so incurs a cost of missing incremental DRV revenue. To ensure peak hour capture, operators can inform discharge of their asset using NYISO's day ahead load forecast on days with high forecasted loads. NYISO's day-ahead load forecast has correctly identified the peak hour in eight of the last 10 years, missing by no more than two hours in the other two. That track record gives four-hour batteries a strong basis for confidently capturing ICAP Alt 3, even as the peak hour is expected to shift later and eventually move outside current DRV windows

How Do Charging Costs and Geography Shape Storage Economics?

Storage projects pay for the power they use to charge in ways solar never has to consider. Three cost components dominate: supply prices tied to hourly zonal day-ahead energy prices, as-used demand charges triggered by charging during defined daytime windows, and contract demand charges based on a project's maximum charging and export capacity.

Together, these costs push most VDER storage projects toward an overnight trickle-charging strategy: reducing output below nameplate capacity and charging steadily overnight, when energy prices are typically lowest and as-used demand charges don't apply. Optimal overnight charging rates allow for the project to fully charge in order to preserve DRV and energy arbitrage, as illustrated in **Figure 2**.

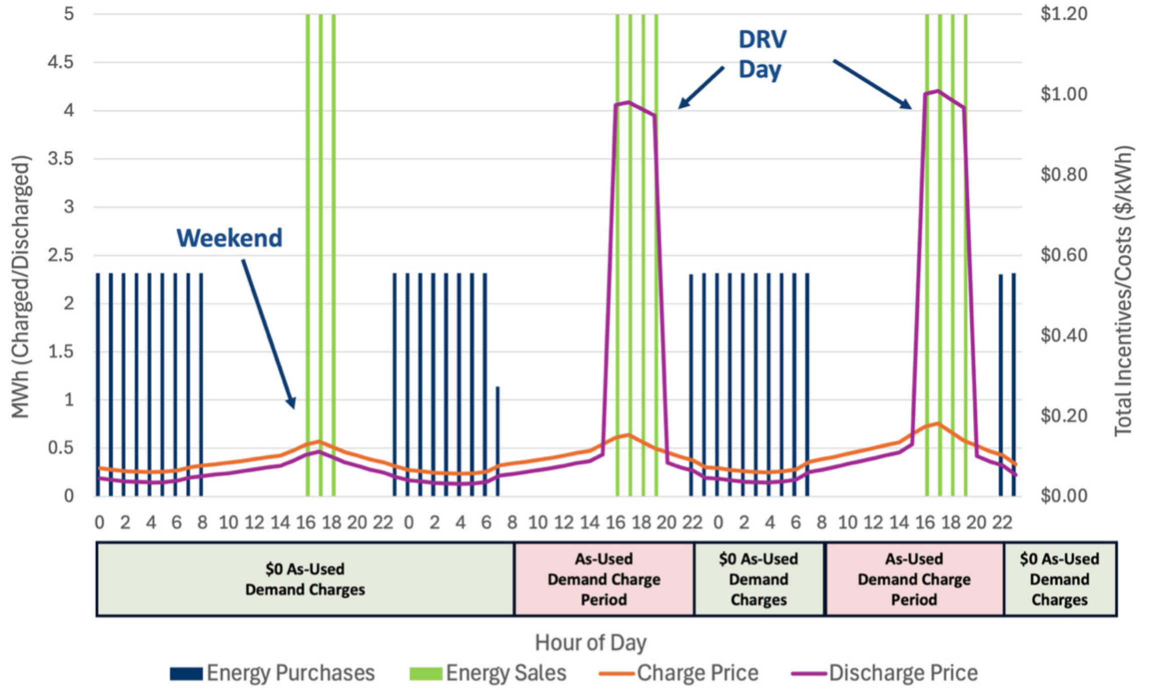

Figure 2. Charging and Discharging Regime, ConEd 5 MW, 4-hour BESS

Costs vary considerably depending on utility territory, with real consequences for project economics. For instance, National Grid's contract demand charge runs about $0.45 per kilowatt-month, while NYSEG's runs roughly $4.90, nearly 10 times higher. NYSEG's as-used demand charge window is also longer, forcing projects to charge at a higher rate, incurring more contract demand charges. That combination makes National Grid a friendlier upstate territory for storage.

As developers look where build, they must also be mindful of charging and discharging restrictions that may be imposed on projects. In interconnection studies, utilities may dictate when a project can charge and discharge and at what rates. Charging restrictions overnight that eat into a preferred trickle charging strategy or discharging restrictions that conflict with DRV or ICAP can greatly impact project economics.

What's Next for VDER Storage in New York?

In the near term, the DPS released proposed DRV values in December 2025 that would raise compensation for most utilities, with National Grid and NYSEG seeing especially large increases. Ascend expects these proposed values to be finalized largely as written by the end of 2026.

Longer term, tension is expected to grow between VDER's current structure, built around a summer-peaking system, and the grid NYISO is forecasted to become. NYISO projects a shift to winter peaking by 2040, and regulators will likely need to revisit several pieces of the program to keep incentives aligned with that shift: how the ICAP market peak hour is defined, whether winter DRV windows get added, whether DRV windows need to lengthen to reflect longer winter peaks, and whether those windows should shift later in the day.

Interested in Learning More?

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