Enhancing PJM's Energy Storage Resource Model for Anticipated Battery Growth

PJM Interconnection

June 3, 2026

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Contents

I. Executive Summary

PJM expects a significant increase in the penetration of battery storage resources by the end of the decade. Thousands of megawatts of storage, either standalone or as part of a Mixed Technology Facility (MTF),[1] are currently under construction in the PJM region. **Figure 1** shows the total amount of battery energy storage in service, or anticipated to be in service, by year, through 2030. Close to 5,000 MW of battery storage are expected to be online by 2030. An additional 6,336 MW of standalone storage and 2,048 MW of MTF capability that includes storage are currently proceeding through Transition Cycle 2. In Cycle 1, the number of storage projects exceeded all other technology types, – 349 projects at 66.5 GW.[2]

Figure 1. Wholesale Battery Energy Storage Development in PJM, Cumulative[3]

	2013	2014	2015	2016	2018	2019	2020	2021	2023	2024	2025	2026	2027	2028	2029	2030
Energy (Total)	2	22	79	89	129	155	155	156	217	260	280	615	1,215	2,279	3,694	4,774
Capacity (CIRs)	-	-	-	-	-	-	4	4	24	25	25	320	677	1,373	2,190	3,132

In an effort to anticipate the impacts of increasing volumes of energy storage on the grid, PJM is reviewing its existing rules for Energy Storage Resources (ESRs) participating through PJM's Energy Storage Resource Participation Model in order to ensure that they support system reliability. This review included lessons learned from other ISOs/RTOs that have integrated large amounts of battery storage on their systems, feedback from current ESR Model Participants and storage developers in the PJM service area, and industry research.

This paper is intended to support the Energy Storage Resource Model Enhancements stakeholder process beginning in July 2026.[4] The issue areas identified are priority items around which stakeholders have expressed considerable interest. They do not represent an exhaustive list of topics. Additional items may be discussed within the stakeholder process, so long as they fall within the scope of the approved Issue Charge. The summary below highlights PJM's initial recommendations, each of which is detailed further in this paper.

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[1] A Mixed Technology Facility is a facility that features more than one technology type behind one Point of Interconnection.
[2] PJM Inside Lines
[3] Queue data pulled May 21, 2026.
[4] See Issue Tracking.

Recommendations for Opportunity Cost in Cost Offers

1 | Develop a consistent opportunity cost calculation methodology for inclusion in cost offers. PJM proposes to develop a common cost offer methodology for resources in the ESR Participation Model that explicitly accounts for opportunity costs. Once defined, this methodology would be included in Manual 15 as the "default" for participants in the ESR model. Resources would be able to propose alternate methodologies in collaboration with PJM and the IMM, as they are able to today. The below represents PJM's directional thinking around a more defined cost offer for ESR Model Participants and do not constitute a full and final proposal.

- ***Day-Ahead Market*:** The day-ahead cost offer cap could be the status quo $1,000/MWh energy soft offer cap. While an ESR is a supply resource, it is also an important instrument of arbitrage and can lead to broader price convergence between the Day-Ahead and Real-Time markets. As such, it may be sensible to tie the cost-based offer to the offer at which other supply resources can bid, particularly in the Day-Ahead Market, where virtual activity diversifies eligible supply and helps to mitigate market power. Alternative approaches may also be reasonable, but have specific drawbacks.
- ***Real-Time Market:*** The real-time cost offer cap could be calculated as the maximum of the battery's incremental energy cost and opportunity cost.

Cost Offer Cap = Max(Incremental Energy Cost, Opportunity Cost), where:

Incremental Energy Cost = Charging Cost + Variable Operation and Maintenance Adder

- Charging Cost = Average of lowest N DA LMPs at applicable pnode/Roundtrip Efficiency
- Maintenance Cost Adder defined in Fuel Cost Policy
- Operating Cost Adder defined in Fuel Cost Policy

Opportunity Cost = Maximum DA LMP at applicable pnode, capped at $2,000

Under predefined emergency conditions:

Cost Offer Cap = $2,000

Incremental Energy Cost: The components of the incremental energy cost would remain the same. However, rather than leaving the determination of the charge cost calculation to each individual market participant's Fuel Cost Policy, as is done today, PJM is considering implementing a default charge cost calculation. One option is to utilize the average of the N lowest day-ahead Locational Marginal Prices (DA LMPs) at the applicable pnode, where N is the battery's duration, divided by roundtrip efficiency. This calculation is based on the assumption that the battery will charge during the lowest-priced intervals. The use of DA LMP aligns the input data used to determine the charging costs with that used to calculate opportunity cost.

Opportunity Cost: The opportunity cost could be defined as the maximum DA LMP at the applicable pnode. PJM believes DA LMPs are the best proxy for real-time prices, and their use strikes the correct balance between simplicity and accuracy, especially in the absence of defining cost offers based on state of charge (SOC). Further, the use of the maximum DA LMP value may be sensible because the default value serves as a cap on the cost-based offer, rather than a default value inserted by the RTO. Because batteries derive revenue from energy arbitrage, they have an inherent incentive to submit lower cost-based offers to clear during the highest-priced hours.

Increased cost offer cap under emergency conditions: Under tight system conditions, an opportunity cost that relies on day-ahead prices may yield a cost offer that is too low, resulting in suboptimal dispatch and reliability risk due to low fleetwide state of charge. Discrepancies between day-ahead and real-time conditions may be handled via a multiplier, as is done by the CAISO. A multiplier, however, is difficult to define and will likely be too high on most days and too low under very tight system conditions. Rather than using a multiplier, PJM is considering permitting the cost offer cap in the real-time market to increase to $2,000 under predefined emergency conditions.

Recommendations for SOC Management

1 | Account for an ESR Model Participant's SOC in Energy Market dispatch decisions. In the Day-Ahead Market, PJM proposes to use a rolling calculation to account for, but expressly not optimize, SOC over the 24-hour study period in order to ensure that an ESR does not receive an infeasible dispatch. To facilitate this process, participants will be able to enter the following parameters in Markets Gateway: Day-Ahead State of Charge, Minimum State of Charge/Maximum State of Charge, Roundtrip Efficiency. The day-ahead commitment and dispatch software will schedule the resource for each hour based on its incremental energy offer curve while respecting the minimum and maximum SOC limits in each hour.

2 | Account for an ESR Model Participant's SOC in ancillary services markets clearing. PJM proposes to recognize the change in an ESR's SOC due to ancillary service deployment and account for SOC needs to allow resources to provide ancillary services in future intervals. These reforms will ensure that an ESR Model Participant has sufficient SOC to provide all services for which it is scheduled in both the current and upcoming intervals, as appropriate.

3 | Do not adopt central SOC management and optimization at this time. PJM believes it is reasonable to implement an SOC accounting process that prevents infeasible dispatch while continuing to allow each ESR Model Participant to manage their SOC. Centralized SOC management, including RTO-led SOC optimization, would require significant software development time and resources and may not yield meaningful benefits without multi-interval dispatch and settlement.

Recommendations for Inter-Day Offer Rules

1 | Do not alter inter-day offer rules at this time. PJM does not recommend changing its inter-day offer rules as other proposed changes should sufficiently address these concerns. Today, the inability to increase offers if a resource was committed in the Day-Ahead Market[5] is exacerbated by the inability to reflect opportunity costs in cost-based offers. Assuming that this paradigm is altered, PJM expects that the ability to switch to the cost-based schedule in real-time will largely mitigate this issue.

[5] While PJM does not commit resources in the ESR model, a resource that self-schedules online is considered "committed" in DA, even if it is not dispatched for positive/negative megawatts.

Recommendations for the Energy Must-Offer Requirement

1 | **Implement an hourly offer equal to the resource's full operating range:** PJM proposes to require an ESR Market Participant to capture in its offered charge/discharge economic min and max parameters the full range of the resource in every hour of the day. The market participant would then manage its state of charge and times of dispatch through its competitive energy offers. In theory, this option provides a lot of flexibility to the market participant while addressing any concerns about withholding.

2 | **Alternatives:** PJM's preferred approach proposed above depends on PJM successfully implementing SOC tracking and disallowance of infeasible dispatch. If this is not feasible to implement in a timely manner, PJM could consider the following two alternate approaches in the interim. PJM recommends adoption of option 2b, which would also allow ESRs to meet their energy must offer by offering their full megawatt output capability in the number of hours equal to their duration (as described in option 2a) but would provide additional flexibility to market participants while still guaranteeing that the resources' full capability is available to the market.

(a) **Offer based on ICAP and duration:** PJM could require the ESR to offer its committed ICAP for at least the number of hours equal to its duration. For example, a 10 MW, four-hour battery would be required to offer 10 MW in at least four hours to meet the Must-Offer Requirement. If this option is adopted, PJM proposes to permit the market participant to determine in which hours the offer is made. PJM does not recommend specifying the hours in which an energy offer must be made.

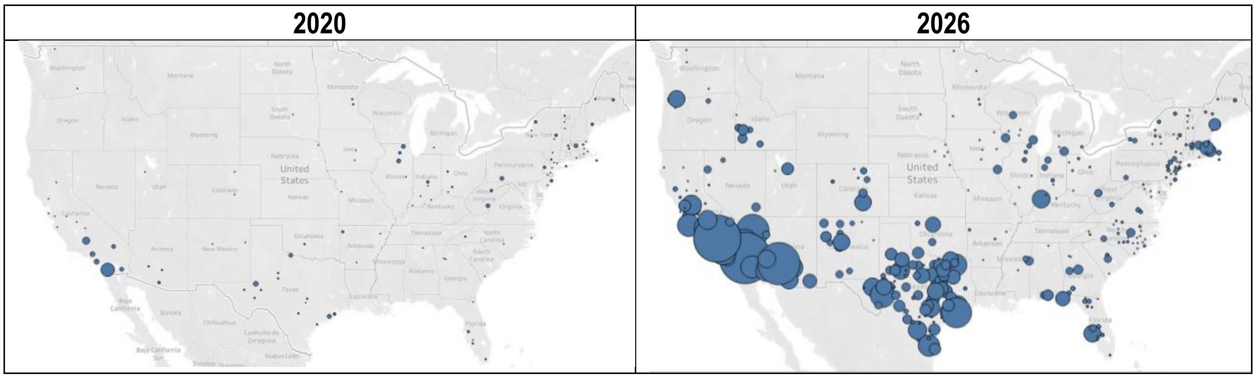
(b) **Offer based on the asset's energy capability:** PJM could require ESRs to offer an energy quantity that, over 24 hours, equals their total energy capacity, based on the battery's ICAP and duration. For example, a 10 MW, four-hour battery would be required to offer at least 40 MWh of energy in the Day-Ahead Market to meet the Must-Offer Requirement. Such a requirement would provide the market participant with the most flexibility to optimize the battery's operation. Meanwhile, PJM would be guaranteed energy offers that account for the full capability of the resource.

II. Overview of Battery Storage in PJM's Markets

A. Drivers of Battery Storage Growth in PJM

Battery energy storage has seen rapid growth in recent years. Since 2020, utility-scale storage capacity in the United States increased exponentially, from just 1.5 GW in 2020 to over 46 GW today, as seen in **Figure 2**.[6] Of this total, 16 GW entered service in the last year alone. The majority of this operating capacity has been deployed in markets operated by CAISO and ERCOT, although the geographic footprint of storage deployments continues to widen.[7]

Figure 2. Utility-Scale Battery Storage



Circle size denotes cumulative nameplate capacity.

In PJM, battery storage systems have seen a slower rate of growth. While the RTO has had several dozen storage facilities representing ~400 MW capability participating in its Regulation Market for several years, and several thousand megawatts of pumped hydro participating across all its markets for longer, only a handful of batteries utilizing the ESR model have provided capacity and energy to date. This trend is likely to change. Several factors portend a significant expansion of this resource in PJM's footprint by the end of the decade.

Abundant Storage in PJM Interconnection Queue

PJM expects a significant increase in the penetration of battery storage resources by the end of the decade. Thousands of megawatts of storage, either standalone or as part of a Mixed Technology Facility (MTF),[8] are currently under construction in the PJM region. **Figure 3** shows the total amount of battery energy storage in service, or anticipated to be in service, by year, through 2030. Future projects are those that have completed the study process and obtained a final agreement (ISA/GIA or WMPA).[9] Close to 5,000 MW of battery storage are expected to be online by 2030. An additional 6,336 MW of standalone storage and 2,048 MW of MTF capability that includes storage

[6] EIA, Monthly Electric Generator Inventory (March 2026)
[7] EIA, Monthly Electric Generator Inventory (March 2026)
[8] A Mixed Technology Facility is a facility that features more than one technology type behind one Point of Interconnection.
[9] Figure 2 includes queue statuses of in service, engineering & procurement, and under construction. Active projects and suspended projects whose revised in service dates have passed.

are currently proceeding through Transition Cycle 2. In Cycle 1, for which the application window closed in April 2026, there were more storage projects than any other type of technology – 349 projects at 66.5 GW.[10]

Figure 3. Wholesale Battery Energy Storage Development in PJM, Cumulative[11]

	2013	2014	2015	2016	2018	2019	2020	2021	2023	2024	2025	2026	2027	2028	2029	2030
Energy (Total)	2	22	79	89	129	155	155	156	217	260	280	615	1,215	2,279	3,694	4,774
Capacity (CIRs)	-	-	-	-	-	-	4	4	24	25	25	320	677	1,373	2,190	3,132

Outside of the traditional queue, PJM's recent reforms to Surplus Interconnection Service (SIS)[12] have created a more viable pathway for the interconnection of battery storage at existing generator sites. SIS allows a developer to add a new resource to the Point of Interconnection (POI) of an existing facility via an expedited process, so long as the new resource does not increase the site's overall maximum facility output (MFO) or its number of Capacity Interconnection Rights (CIRs) or trigger network upgrades. The addition of storage capability to existing solar or wind generation facilities is widely viewed as the most promising use-case of the SIS process. The battery would allow a fuller use of the interconnection service by discharging in intervals where the intermittent resource is not using its full MFO.

Attractive Economic Conditions

The value of services provided by battery storage is greatly influenced by the penetration of renewable energy within a power system. For example, higher levels of renewables within the generation mix create a need for additional firm capacity to maintain system reliability. Meanwhile, in day-to-day operations, growing wind and solar may increase the need for additional frequency regulation, a service for which battery storage is uniquely suited, while the steepening net load curve could lead to longer periods of negative pricing and curtailments, and the need for ramp and uncertainty reserves on the system[13], presenting a possible opportunity for energy arbitrage. Historically abundant capacity resources resulted in low-capacity prices, while low penetration of intermittent generation, particularly solar, has yielded insufficient energy price arbitrage opportunities. This is changing rapidly. Tightening demand and supply

[10] PJM Inside Lines
[11] Queue data pulled May 21, 2026.
[12] FERC Docket No. ER25-778
[13] See PJM's Reserve Certainty Senior Task Force (RCSTF) proposal

conditions are expected to continue to put upward pressure on capacity market prices, while rapid growth in solar is likely to provide greater opportunity for energy market arbitrage.

Supportive State and Federal Policies

A number of PJM states have adopted legislation and other policies to support the growth of battery storage. In addition to state procurement targets and incentive programs, battery storage systems continue to be eligible for federal tax credits. Although the 2025 federal spending bill cut most solar and wind tax credits, it retained both the Investment Tax Credit (ITC) and the Production Tax Credit (PTC) for battery storage. Projects that begin construction before 2033 remain eligible for both the ITC and PTC. Those that begin construction in 2026, and meet certain domestic content and labor provisions, can receive an ITC of up to 50%. The ITC is slated to decline annually before being phased out in 2035. The PTC will also remain at current levels through 2033, after which it will be phased down and eliminated in 2035.[14] The retention of the federal tax credits is expected to continue to accelerate storage deployment across the country.

B. Market Design for the Future

PJM developed the Energy Storage Resource (ESR) Participation Model in response to FERC Order 841. Order 841 aimed to remove barriers to the participation of electric storage resources in the wholesale markets by requiring each ISO/RTO to establish a participation model that recognized the physical and operational characteristics of these resources. PJM implemented the ESR Participation Model in December 2019 as an opt-in model for any resource meeting the ESR definition.[15] However, participation has remained small. The vast majority of PJM's battery storage fleet has elected to participate in PJM's markets outside of the model, given that the business rules unique to the model – specifically, the ability to economically offer charging megawatts – provide relatively little value for resources that participate solely in the Regulation Market. This is likely to change.

Given the shifting market conditions and PJM's project pipeline, the RTO can expect significant battery storage capability in the ESR model in the coming years. This presents an opportunity to review the existing ESR Participation Model and related business rules to ensure that PJM can most cost-effectively utilize resources participating in this model for the benefit of system reliability.

[14] What the Budget Bill Means for Energy Storage Tax Credit Eligibility

[15] An Energy Storage Resource is defined in PJM's Tariff as "as resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in PJM Energy, Capacity and/or Ancillary Services market as a Market Participant."

III. Issue Areas in PJM's Energy Storage Resource Market Model

This paper is intended to support the Energy Storage Resource Model Enhancements stakeholder process.[16] The issue areas discussed in this section are priority items around which stakeholders have expressed considerable interest. They do not represent an exhaustive list of topics. Additional items may be discussed within the stakeholder process, so long as they fall within the scope of the approved Issue Charge.

A. Opportunity Cost Representation in Cost Offers

PJM's Current Rules and Requirements

Different types of opportunity costs arise from different operational circumstances, and it is helpful to define these broadly to inform thinking on how ESR Model Participants are able to reflect such opportunity costs:

- **Forward Energy-Limited Opportunity Cost**: Opportunity cost in the energy market generally comprises foregone revenue associated with being run in one interval when it could have been more profitable to run in a higher-valued interval. A resource can have energy limitations such that, if the unit runs now, it may not be available to run later. This can take shape over different time granularities for different reasons:
  - **1 |** Resources with environmental limitations, temporary physical equipment limitations or temporary fuel supply limitations have finite run hours across a year or season. Such resources are permitted to utilize the IMM Opportunity Cost Calculator (OPC), which generates a cost-based adder that "optimizes" potential run hours.
  - **2 |** Use-limited resources such as battery storage face inter-temporal opportunity cost related to charge and discharge decisions. Although technically allowable in PJM's cost development guidelines, there is limited ability to include forward opportunity costs in cost-based offers today.
- **Ancillary Services Opportunity Cost**: A resource providing reserves or regulation in a given interval "loses" the opportunity to provide its full range of energy, or another ancillary service, in that interval. A "product substitution" lost opportunity cost (LOC) is utilized in the pricing of ancillary services. Today ESR Model Participants can receive this LOC, and this is endogenously calculated in PJM's market engines.
- **Uplift for Lost Opportunity Cost**: Resources can also be paid lost opportunity cost when their dispatch instructions differ from their previous commitment. This is important for system reliability by ensuring resources are incentivized to follow PJM dispatch because they will be compensated for doing so. Storage resources may be eligible for lost opportunity costs, as discussed in Manual 28.

This section will focus on the ability of ESR Model Participants to reflect their forward opportunity costs in cost-based offers. When running economically, a resource has the ability to manage its anticipated opportunity cost and other factors to profit maximize using its price-based offers. When a resource is found to have structural market power, however, such market power is mitigated by dispatching the resource on the lower of its price-based or cost-based offer. Even if the resource is committed to its price offer in day-ahead, if costs increase in real-time, a committed unit cannot increase its price offer. Rather, it can request to be placed on its cost offer. In either circumstance – whether

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[16] See Issue Tracking.

placed on cost due to market power mitigation or to reflect real-time cost changes – a cost offer that does not account for opportunity cost could lead to inefficient dispatch of the unit.

Today, ESR Model Participants have a very limited ability to, and effectively do not, represent opportunity costs in their cost-based offers. Per PJM's cost development guidelines and Manual 15, cost-based offers for storage resources can include charge cost and efficiency factor, but this does not capture the forward, inter-hour nature of the opportunity cost associated with charging and discharging. Resources with environmental limitations or temporary physical equipment or fuel supply limitations are expressly permitted to reflect those opportunity costs in cost-based offers per Schedule 2 of the Operating Agreement. Opportunity costs not defined in the Operating Agreement may be submitted to PJM and PJM's Market Monitor for approval pursuant to the Cost Methodology and Approval Process. However, no resources in the ESR model have submitted an opportunity cost methodology to date.

The inability to reflect opportunity costs of charging or discharging in a one interval versus another in cost-based offers can have a significant impact on the ability of an ESR to manage its own state of charge (SOC) if mitigated and may result in suboptimal dispatch of the resource. This risks leaving the RTO with a degraded battery fleet during tight system conditions.

The ISO/RTO Landscape for Opportunity Cost Considerations

Other ISO/RTOs have developed approaches to permit opportunity cost to be reflected in cost-based offers.

Table 1. Accounting for Opportunity Costs in Cost-Based Offers

(a) ISO/RTO Comparison

	PJM	CAISO	ERCOT	ISO-NE	MISO	NYISO	SPP
Common Calculation	No	Yes	Minimal mitigation applied	Under Development	No	Yes	Yes
Ability to Submit Alternative Methodology	Yes	No, but may rank methods to be used	N/A	Yes	Yes	Yes	Yes
Calculated by	Participant / IMM[17]	ISO	N/A	Participant / IMM	Participant / IMM	ISO	Participant / IMM

[17] Participant would calculate their alternative methodology. The existing M15-defined Opportunity Cost Calculator is executed by the IMM to determine a resource's Opportunity Cost Adder.

(b) Detail

<table>
<tr><th></th><th>Detailed Description</th></tr>
<tr><td>CAISO</td><td>Enables forward opportunity cost in offers
A Default Energy Bid (DEB) is utilized for any resource determined to have the potential to exert market power.
DEB = Max(Charging Cost, Opportunity Cost)*1.1
The opportunity cost is calculated using the Nth highest priced day-ahead LMP, where N is the duration of the resource (e.g., a four-hour battery's opportunity cost would be the fourth highest day-ahead LMP).
Charging cost assumes that the battery will charge during the least expensive continuous block of time during the day.
The day-ahead storage DEB does not include opportunity cost due to the 24-hour optimization horizon.</td></tr>
<tr><td>ERCOT</td><td>Battery storage resources are, effectively, rarely subject to mitigation. When a storage unit is flagged as having market power in the Constrained Competitiveness Test (CTT), its Mitigated Offer Cap is set at the systemwide offer cap.
ERCOT has been exploring a "light-touch" alternative. Under the proposal:
Battery storage would be mitigated only when available stored energy for the next hour exceeds 25% and it can help the shift factor by at least -0.2.
If mitigated, the unit's Mitigated Offer Cap curve would be set at the lowest constraint contribution for any identified constraints plus the System Lambda from Step 1 of SCED, less $0.01 (the highest possible offer that will allow SCED to resolve the constraint).</td></tr>
<tr><td>MISO</td><td>Enables inter-hour opportunity cost to be reflected in reference levels
No common opportunity cost calculation is provided for ESRs. Rather, ESRs may request cost-based (consultative) reference level where opportunity costs to be considered. The specific values are determined in consultation with the IMM.</td></tr>
<tr><td>NYISO</td><td>Enables inter-hour opportunity cost to be reflected in offers
Storage Reference Level = Opportunity Cost + VOM + Risk Adder
Estimates dynamic opportunity costs for a storage resource on a daily basis to establish its reference level. This dynamic opportunity cost is based on the previous 30-day history of available LBMPs for the Day-Ahead Market, adjusted for fuel price changes; and the day-ahead LBMPs from the current market day for the Real-Time Market.</td></tr>
<tr><td>SPP</td><td>Enables inter-hour opportunity cost to be reflected in cost offers.
An ESR's mitigated Energy Offer Curve must include: (i) charging cost and (ii) opportunity cost, both adjusted for roundtrip efficiency.
Charging cost is the cost at which the ESR charged; opportunity cost is the average profit in the next hour forgone by charging or discharging in the current hour.
A proxy for the sum of the charging cost and opportunity cost is the average LMP that is expected for the next operating hour. This value is calculated as the average of the LMPs for the most recent 45 days, comparing like operating hours.
A market participant may submit for approval by the Market Monitor a modified mitigation methodology for an ESR that considers the ESR's storage horizon and any cycling limitations.</td></tr>
</table>

Proposed Path Forward

1 | Develop a consistent opportunity cost calculation methodology for inclusion in cost offers.

PJM proposes to develop a common cost offer methodology for resources in the ESR Participation Model that explicitly accounts for opportunity cost. Once defined, this methodology would be included in Manual 15 as the "default" for participants in the ESR model. Resources would be able to propose alternate methodologies in collaboration with PJM and the IMM, as they are able to today. The below represents PJM's directional thinking around a more defined cost offer for ESR Model Participants. PJM understands that many aspects of this issue warrant broader discussion. The ideas below are intended to start the conversation and do not constitute a final and full proposal.

- ***Day-Ahead Market*:** The day-ahead cost offer cap could be defined as the status quo $1,000/MWh energy soft offer cap. While an ESR is a supply resource, it is also an important instrument of arbitrage and can lead to broader price convergence between the Day-Ahead and Real-Time markets. As such, it may be sensible to tie the cost-based offer to the offer at which other supply resources can bid, particularly in the Day-Ahead Market, where virtual activity diversifies eligible supply and helps to mitigate market power. Alternative approaches may also be reasonable, but have specific drawbacks. Using historic LMPs as is done by several other ISOs/RTOs (e.g., average of the max DA LMP over the prior X days) as a proxy for the DA opportunity cost may be insufficient because prices on the days when the system would most benefit from optimal use of battery storage – under tight system conditions – are likely to be much higher than the values obtained by averaging prices over some set number of prior days. Using the LMPs that come from the market power run, as is done by CAISO, results in cost offers that are based on non-public price data.
- ***Real-Time Market:*** The real-time cost offer cap could be calculated as the maximum of the battery's incremental energy cost and the opportunity cost as further described below.

Cost Offer Cap = Max(Incremental Energy Cost, Opportunity Cost), where:

Incremental Energy Cost = Charging Cost (Fuel Cost) + Variable Operation and Maintenance Adder

- Charging Cost = Average of lowest N DA LMPs at applicable pnode/Roundtrip Efficiency
- Maintenance Cost Adder defined in Fuel Cost Policy
- Operating Cost Adder defined in Fuel Cost Policy

Opportunity Cost = Maximum DA LMP at applicable pnode, capped at $2,000

Under predefined emergency conditions:

Cost Offer Cap = $2,000

Incremental Energy Cost

The components of the incremental energy cost would remain the same. These are the fuel cost and variable operation and maintenance adders, if justified. Today, a battery's fuel cost is defined in Manual 15 as the average charge cost divided by the efficiency factor. The specific methodology to calculate the average charge cost is determined and documented by the market participant in the Fuel Cost Policy. Rather than leave the determination of the charging cost calculation to each individual market participant, thereby potentially introducing differences between the input data and lookback period used to calculate the different components of the cost offer, PJM is considering implementing a default charging cost calculation.

Specifically, the average charge cost could be defined as the average of the N lowest day-ahead LMPs at the applicable pnode, where N is the battery's duration, divided by roundtrip efficiency. This calculation is based on the assumption that the battery will charge during the lowest-priced intervals. The use of DA LMP aligns the input data used to determine the charging costs with that used to calculate opportunity cost.

An alternative method to charging cost could employ the inventory approach defined in Manual 15 for pumped storage hydro fuel cost, calculated on a seven-day rolling basis by multiplying the real-time bus LMP at the plant node by the actual power consumed when pumping divided by the pumping efficiency. However, a case could be made for differing lookback periods based on storage duration when applying the inventory approach to a battery. If the inventory approach is preferred, more discussion will be needed on internal consistency with the opportunity cost in the Cost Offer Cap calculation proposed above. Specifically, it may not make sense to take the maximum of two cost components with different input data and lookback periods.

Opportunity Cost

The opportunity cost could be defined as the maximum DA LMP at the applicable pnode. PJM believes DA LMPs are the best proxy for real-time prices, and their use strikes the right balance between simplicity and accuracy, especially in the absence of defining cost offers based on state of charge. Further, the use of the maximum DA LMP value may be sensible because the calculation will serve as a cap on the cost-based offer, rather than a default value inserted by the RTO. Market participants may submit values that are below this cap. Because batteries derive revenue from energy arbitrage, they have an inherent incentive to submit lower cost-based offers if necessary to clear during the highest-priced hours. Meanwhile, reliance on the maximum DA LMP as the opportunity cost offers sufficient protection from premature RT dispatch and protects PJM from entering tight operating conditions with a depleted battery fleet. PJM provides a comparison of the proposed opportunity cost cap methodology with other opportunity cost cap methodologies considered in Appendix A: Numerical Analysis of the Opportunity Cost Cap Methodologies.

Increased Cost Offer Cap under Emergency Conditions

Under tight system conditions, an opportunity cost that relies on day-ahead prices may yield a cost offer that is too low, resulting in suboptimal dispatch. Some ISOs/RTOs address the potential uncertainty between day-ahead and real-time prices using a multiplier (e.g., CAISO uses a 1.1 multiplier). Determining an appropriate multiplier, however, is difficult. A static multiplier is likely to be too high on most days and too low under very tight system conditions. To avoid an administratively determined multiplier, PJM may consider permitting the cost offer cap in the Real-Time Market to increase to $2,000 under predefined emergency conditions. Triggering conditions could include the declaration, for the operating day, of a Maximum Generation Alert, EEA1, Hot Weather Alert, Cold Weather Alert and/or Conservative Operations.

B. State of Charge Management

The state of charge (SOC) represents the amount of energy (megawatt-hours) stored by an ESR Model Participant and represents the resource's physical ability to charge from or discharge into the grid. The manner in which operational and market models track and utilize an ESR's SOC has implications for how efficiently these resources can be utilized to meet system needs. Generally, SOC can be managed solely by the market participant (self-managed), solely by the RTO/ISO (centrally managed) or a combination of both. This section examines PJM's current SOC management practices and reviews the approaches of other ISO/RTOs with larger amounts of storage to inform how PJM could refine its SOC management approach as an increasing number of resources enter the ESR model.

PJM's Current Rules and Requirements

During the Order 841 compliance process, PJM proposed, and FERC accepted, a phased implementation approach to SOC management. In the first phase, PJM would not account for SOC when making dispatch decisions for resources utilizing the ESR Participation Model in either the energy or ancillary services markets. Rather, these units would use available bidding parameters, operating modes and offer prices to manage their SOC. This is the model that remains in place today.

Bidding Parameters

- Minimum and Maximum Charge and Discharge Limits, representing Economic Minimum and Economic Maximum, depending on operating mode
- Charge/Discharge Ramp Rate
- State of Charge, an optional hourly parameter used for awareness only

Operating Modes

- *Continuous Mode* allows for an ESR to be dispatched across its full available operating range. This represents the ability to immediately transition from withdrawing to injecting energy and includes both negative and positive megawatt quantities. This mode requires the ESR's Maximum Discharge Limit to be greater than or equal to zero and Maximum Charge Limit to be less than or equal to zero. Ramp rate in continuous mode is infinite to allow for frequent switching between charging and discharging, if supported by an ESR's offer curve.
- *Charge Mode* allows for offering into the energy markets with a negative megawatt dispatchable range only. This represents withdrawals from the grid only and includes only negative megawatt quantities. This mode requires the ESR to have a Minimum Charge Limit and Maximum Charge Limit less than or equal to zero, and a defined ramp rate.
- *Discharge Mode* allows for offering into the energy markets with a positive megawatt dispatchable range only. This represents injections into the grid and includes only positive megawatt quantities. This mode requires the ESR to have a Minimum Discharge Limit and Maximum Discharge Limit greater than or equal to zero, and a defined ramp rate.

Other Data

- SOC Telemetry is received in real-time. Today, these values are only used in settlement calculations to determine uplift payments if the resource receives a manual dispatch to address a system constraint.[18]

The rationale for the decision to not account for SOC in dispatch in PJM's initial implementation of the ESR Participation Model was multifaceted. First, given PJM's limited experience with battery storage, an approach to utilize SOC management in general, and central optimization in particular, was considered premature. Second, with the pending transition to the Next Generation Markets (nGEM) market-clearing software, which was expected to have SOC accounting capability, PJM did not believe it was prudent to expend resources to duplicate that capability in its legacy systems. Finally, PJM's battery fleet at the time comprised primarily short-duration batteries participating in the Regulation Market only. Under a bidirectional regulation signal, battery dispatch is generally expected to be energy neutral over the regulation period. This allowed for the simplifying assumption that any net impact of regulating on an energy-limited resource's state of charge would be minimal.

As battery penetration in PJM increases, however, the lack of boundary conditions to prevent sending an ESR Model Participant a dispatch signal that it cannot meet given its current SOC introduces reliability risks. Meanwhile, existing limitations to representing opportunity costs in these resources' cost offers, as well as to updating price offers as conditions change between day-ahead and real-time, further constrain the resource's ability to manage its state of charge through offers as originally envisioned. Finally, as PJM moves to separate Regulation Up and Regulation Down products, and batteries begin providing a more diverse set of market products and services, the prevailing assumptions about energy neutrality no longer hold true.

To that end, PJM plans to account for the SOC of resources in the ESR Participation Model in market scheduling and dispatch. Importantly, Order 841 does not establish strict criteria for ISOs/RTOs to "account for" SOC. Options for SOC management range from the simpler prevention of infeasible dispatch to the more complex full SOC optimization. During the compliance process, PJM committed to, at minimum, not sending ESR Model Participants dispatch instructions that violate their physical and operational limits. PJM intends to utilize the ESR Enhancements Stakeholder Process to review this approach to SOC management for energy and ancillary services markets. This is intended to ensure that PJM's market design provides ESR Model Participants with the tools necessary to effectively manage their SOC to ensure market efficiency and that their dispatch supports reliable operations.

The ISO/RTO Landscape for State of Charge Management

All ISOs/RTOs permit the market participants to manage a battery's state of charge, with most also ensuring that the resource does not receive an infeasible dispatch. CAISO and NYISO also provide the option for the ISO to optimize the battery's SOC across specific time horizons.

Given the depth of its experience with battery storage, CAISO has the most sophisticated set of rules for SOC management, including financially binding optimization in day-ahead and advisory optimization for different look-ahead periods in real-time. CAISO's approach for state of charge management has evolved over time, first ensuring that energy market awards were SOC sufficient, and later expanding the SOC accounting rules to ancillary services.

[18] See Manual 28.

Although ERCOT also has substantial battery storage penetration, the ISO has largely allowed the market participant to manage the resource's SOC, with little to no accounting for SOC in dispatch decisions. This changed in December 2025 with ERCOT's rollout of the Real-Time Co-Optimization plus Batteries (RTC+B). A more detailed comparison of SOC management across CAISO and ERCOT is provided in **Table 2**.

Table 2. State of Charge Management

(a) ISO/RTO Comparison for ESR Models[19]

	CAISO	ERCOT	ISO-NE	NYISO	MISO	SPP
SOC Accounting Approach	ISO-optimized or self-managed; ISO ensures feasibility of dispatch.	Self-managed; ISO ensures feasibility of dispatch in real-time.	Self-managed; ISO ensures feasibility of dispatch in day-ahead.	ISO-optimized or self-managed; ISO ensures feasibility of dispatch.	Self-managed; ISO ensures feasibility of dispatch.	Self-managed; ISO ensures feasibility of dispatch.

(b) Detail

	Detailed Description
CAISO	Parameters: Min/max SOC, HE01 SOC (defaulted to the last SOC from the prior day, or 0 if neither is indicated), end-of-hour SOC (fixed megawatt-hour value or min/max range; RT only) Optimization: Energy & AS awards are co-optimized in DA and the Fifteen-Minute Market (FMM) and subject to SOC constraints. AS awards are fixed in Real-Time Dispatch (RTD), but SOC constraints are enforced in energy dispatch. RT optimizations are advisory; only the first interval is financially binding. Look-Ahead: The look-ahead horizon differs by market as follows: ▪ **DA:** ISO sees HE01 SOC and optimizes charge/discharge across 24 hours. ▪ **RT:** ISO monitors SOC using telemetry and ensures that sufficient SOC is reserved to support market award over the following time horizons: ○ FMM optimizes for two hours ahead. ○ RTD optimizes over 65 minutes (13 five-minute intervals). SOC sufficiency: Storage that provides AS must have sufficient SOC to ensure deliverability. Impacts of AS deployments also reflected in SOC. ▪ **Reserves:** Spin/Non-Spin awards ensure that 30 minutes of SOC is reserved in the FMM and RTD. ▪ **Regulation:** DA awards ensure that one hour of SOC is available, while 30 minutes of SOC is reserved in FMM and RTD.

[19] This does not include comparison of the treatment of pumped storage optimization approaches.

	Detailed Description
ERCOT	Parameters: Min/max SOC, hourly planned SOC Optimization: SOC has not been tracked or optimized in either DA or RT. SOC has been modeled in the RUC run, both day-ahead and then in every hour during the operating day. SOC Sufficiency: SOC sufficiency/dispatch feasibility ensured with the go-live of RTC+B as follows: ▪ **DA**: SOC not considered in the clearing of Energy and AS. ▪ **RT***:* SCED will consider a battery's telemetered SOC to ensure that awards are feasible and that there is sufficient energy to meet the energy and AS awards for their respective duration requirements (e.g., for every 1 MW of a Non-Spin award in any 5-minute interval, a battery must have 4 MWh of energy stored at the start of the interval)
ISO-NE	Parameters: In the Day-Ahead Energy Market, optional bidding parameters allow storage resources to be optimized based on their SOC and duration. These are initial SOC for the day, min/max SOC, and roundtrip efficiency. Optimization: In day-ahead, the parameters can be used to indicate total MWh available for injection onto the grid and a storage resource's duration. The SOC for each hour is dynamically calculated based on the previous hour's SOC, adjusted by the scheduled MW and roundtrip efficiency, while respecting the hourly minimum and maximum and SOC constraints. SOC Sufficiency: In day-ahead, the SOC accounting ensures that assigned reserves are sustainable for one hour to avoid a charging award and reserve assignment in the same hour.

Proposed Path Forward

1 | Account for an ESR Model Participant's SOC in energy market dispatch decisions.

In the Day-Ahead Market, PJM proposes to use a rolling calculation to account for, but expressly not optimize, SOC over the 24-hour study period in order to ensure that an ESR does not receive an infeasible dispatch. To facilitate this process, participants will be able to enter the following parameters in Markets Gateway:

- **Day-Ahead State of Charge:** This is the forecasted state of charge value for the beginning of the first hour of the day.
- **Minimum State of Charge/Maximum State of Charge:** These represent the battery's physical limits. The values can be hourly, or a daily default can be set for all hours.
- **Roundtrip Efficiency:** This parameter (can be updated daily or hourly) will be used to calculate the appropriate increase or decrease in SOC from beginning to end of each hour.

The day-ahead dispatch software will schedule the resource for each hour based on its incremental energy offer curve while respecting the minimum and maximum state of charge limits in each hour. As SOC depletes through the 24-hour period, bid-in Economic Maximum or Economic Minimum for an hour would be permitted to be violated to avoid violating the physical state of charge limits. A numerical example of SOC accounting for energy dispatch is provided in **0**.

Table 3. Accounting for State of Charge in the Day-Ahead Market

	1	2	3	4	5	6	7	8	9	10	11	12
Parameters												
DA SOC (MWh)	38											
Min SOC (MWh)	36	36	36	36	36	36	36	36	36	36	36	36
Max SOC (MWh)	144	144	144	144	144	144	144	144	144	144	144	144
Eco Max (MW)	40	40	40	40	40	40	40	40	40	40	40	40
Eco Min (MW)	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40	-40
Solution												
SOC (MWh)	38	72.0	106.0	131.5	144.0	144.0	114.0	74.0	42.0	36.0	36	36
Energy (MW)	0	-40.0	-40.0	-30.0	-14.7	0.0	30.0	40.0	32.0	6.0	0.0	0.0

Note: Table assumes 40 MW, four-hour battery in continuous mode with 0.85 roundtrip efficiency.

In real-time, the Real-Time State of Charge, received via telemetry, will be incorporated into PJM's real-time market clearing engines, with logic that compares the telemetered value to bid in Minimum/Maximum State of Charge Limits and adjusts dispatch to avoid violating those limits. This will serve to avoid an infeasible dispatch in the cleared interval; at least initially, no look-ahead or optimization will be performed.

The Minimum and Maximum SOC parameters would be input into Markets Gateway by the ESR Model Participant and would be subject to the same rules and requirements as all other parameters for generation resources. Specifically, these parameters would be subject to parameter limitations any time the resource was mitigated, was otherwise operating on cost or under emergency conditions. If a resource owner inputs parameters that do not comport with its energy Must-Offer Requirement, including Min and Max SOC limits that do not permit the unit to be dispatched in accordance with its energy must offer, the resource would be subject to a partial outage.

2 | Account for an ESR Model Participant's SOC in ancillary services market clearing.

PJM proposes to: (A) recognize the change in an ESR's SOC due to ancillary service deployment and (B) account for SOC needs to allow resources to provide ancillary services in future intervals. The former reform, (A), is primarily relevant to regulation clearing. Following the implementation of separate Regulation Up and Regulation Down products, the regulation energy neutrality assumption will no longer be reasonable. As such, PJM should make changes to its market clearing engines to reflect how regulation assignments will impact energy storage resource state of charge to ensure that PJM's dispatch engine does not give ESR Model Participants infeasible energy assignments in the intervals in which they are regulating.

The latter reform, (B), ensures that when PJM's economic dispatch engine gives ESR Model Participants both an energy and one or more reserve assignment(s), that resource has sufficient SOC to provide all of these services in both the current and upcoming intervals, as appropriate. This aligns with the work CAISO undertook in the first half of 2025 to reflect Flexible Ramp Up SOC needs in its market clearing engines.

Moreover, once PJM implements SOC tracking, it will be able to effectively co-optimize energy and reserves. As such, PJM would be able to calculate an ESR Market Participant's reserves capability, as it does for most other resources today, rather than having these resources bid in their reserve capability independently.

3 | Do not adopt central SOC management and optimization at this time.

At this time, PJM believes it is reasonable to implement an SOC accounting process that prevents infeasible dispatch while continuing to allow each ESR Model Participant to manage their SOC. Centralized SOC management, including RTO-led SOC optimization, would require significant software development time and resources. Furthermore, this effort might not yield meaningful benefits without multi-interval dispatch and settlement. These further reforms can be explored if needed after more experience is gained with this asset type and PJM has a better understanding of their costs and benefits.

IMPLEMENTATION CONSIDERATIONS

PJM is progressing through the Next Generation Markets (nGEM) initiative – a major overhaul of the optimization and dispatch technology behind the Day-Ahead Energy Market, Real-Time Energy Market and ancillary services markets. The nGEM version of the Day-Ahead Market Clearing Engine went live in October 2025. Work is now focused on the Real-Time Market Clearing Engine.

Due to the criticality of the work on nGEM for the Real-Time Market Clearing Engine and limited resources, PJM may be constrained until after its completion to implement the functionality to support state of charge accounting.

C. Inter-Day Offer Rules

PJM's Current Rules and Requirements

PJM's ESR Market Participation Model is a self-schedule model. This means that PJM does not make commitment decisions for these resources. In the Day-Ahead Market, the market participant must self-commit (indicates that they are available). They may also enter a profile of hourly differentiated Economic Minimum and Maximum limits for the market day. Each hour reflects the capability to produce or consume energy for the entire hour in megawatt-hours. ESRs are not permitted to have startup or no-load costs. If there is a spread between the entered Minimum and Maximum Charge/Discharge Limits, the unit will be economically dispatched on the participant's bid-in incremental offer curve. The fact that an ESR Model Participant must be self-scheduled online, but can be dispatched economically, may results in ESRs being "committed" in the DA at 0 MW.

In real-time, only resources that do not receive a day-ahead commitment can increase their offers after the rebid period and up to 65 minutes before an operating interval. A resource that is committed in day-ahead on their price-based offer in a given interval, even if that commitment is for 0 MW, cannot increase this offer in real-time. If costs increase in real-time, the market participant may ask PJM to commit the resource on their cost-based offer. Today, however, this option is also suboptimal as the cost-based offer for batteries does not fully account for the opportunity cost incurred in dispatching outside of the highest-priced hours.

The interplay between being committed at 0 MW in day-ahead and therefore being unable to update the price-based offer in real-time, as well as the limitations on the extent to which ESRs are able to represent anticipated opportunity costs in cost-based offers, significantly impacts how flexibly and accurately this resource type can represent their limited energy to the market. This, in turn, could lead to suboptimal real-time dispatch and result in premature depletion of PJM's battery fleet.

Proposed Path Forward

1 | **Do not alter inter-day offer rules at this time.** PJM does not recommend changing its inter-day offer rules as other proposed changes should sufficiently address these concerns. Today, the inability to increase offers if a resource was committed in the Day-Ahead Market is exacerbated by the inability to reflect opportunity costs in cost-based offers. Assuming that this paradigm is altered, PJM expects that the ability to switch to the cost-based schedule in real-time will largely mitigate this issue.

D. Energy Market Must-Offer Requirement

PJM's Current Rules and Requirements

PJM's Tariff provides high-level guidance on the manner in which ESR Model Participants can meet their energy Must-Offer Requirements. The PJM Tariff states that ESR Model Participants with a capacity commitment must self-schedule the unit into the DA Market (i.e., make the unit available to the Day-Ahead Market) with an hourly megawatt quantity that may vary hour to hour from the capacity commitment. No additional detail is provided in the PJM manuals.[20] This lack of detail is confusing to market participants and complicates compliance for battery storage committed for capacity.

The ISO/RTO Landscape

Energy storage resources committed to provide capacity have an energy Must-Offer Requirement in all organized wholesale markets.[21] The requirements differ widely in their specificity, with most being fairly loosely defined. A summary of the energy Must-Offer Requirement, by market, is detailed in **0**.

[20] Tariff, Attachment K, Appx-Section 1.10.1A
[21] Because ERCOT does not have a capacity market, there is no associated energy Must-Offer Requirement.

Table 4. Energy Must-Offer Requirements for Battery Storage Across ISOs/RTOs

	Energy Must Offer
CAISO	California has an hourly Resource Adequacy construct. ESRs with capacity commitment are required to bid their entire RA-committed capacity into the Day-Ahead and Real-Time markets during the hours for which they were procured.
ISO-NE	ESRs with a capacity commitment must offer the minimum of their capacity supply obligation (CSO) or availability (if less than CSO) into the Day-Ahead and Real-Time markets.
NYISO	ESRs with capacity commitment must offer into Day-Ahead Market. Specifically, ESRs must bid as Eco Max, bilaterally schedule, or declare unavailable via outage a total energy quantity equal to or exceeding the ICAP-equivalent of its committed UCAP. These quantities must also include the max of the ESR's: (i) negative Installed Capacity Equivalent (negative UCAP) or (ii) Lower Operating Limit (Max Charge), such that the amount reflects the entire withdrawal to injection operating range. ESRs with a duration limitation must offer during the Peak Load Window for at least the number of consecutive hours that correspond to their Energy Duration Limitation.
MISO	ESRs are required to offer their cleared ICAP into the Day-Ahead Market and first RAC run during the four peak hours each operating day. This is defined as the two hours preceding the peak, the peak hour, and one hour after the peak. The peak period will be based on the forecast published one day prior to the operating day in the Market Report section of the MISO website.
PJM	ESRs with capacity commitment must self-schedule, with a dispatchable range or a fixed megawatt quantity, their capability into the Day-Ahead Market.
SPP	Load Serving Entities are required to offer resources into the Day-Ahead Market and the RUC total megawatts commensurate with their Western Resource Adequacy Program obligations. Any resources awarded in DA/RUC must also be offered into the Real-Time Market. Because the must offer is a quantity requirement, not a facility-specific requirement, LSEs can manage the specific participation of fuel limited resources within the aggregate offer based on the characteristics of their total generation portfolio. Storage charging is added to the hourly expected load that must be met through the energy Must-Offer Requirement.

Proposed Path Forward

1 | Implement an hourly offer equal to the resource's full operating range: PJM proposes to require an ESR Market Participant to offer its full operating range corresponding to the ICAP equivalent of its cleared UCAP via its Economic Minimum and Maximum parameters for each hour in the Day-Ahead Market. The market participant would then manage their state of charge and times of dispatch through their competitive energy offers. In theory, this option provides a lot of flexibility to the market participant while addressing any concerns about withholding. This option has several complexities:

(a) In a system where PJM does not optimize dispatch across a 24-hour period, offers that reflect the battery's full operating range in every hour may misrepresent the resource's true capability in a given interval. That said, absent PJM-managed optimization, the same issue could arise even if megawatt quantities varied hour-to-hour simply because the market participant lacks perfect foresight.

(b) Under PJM's existing cost offer rules, where offers cannot reflect opportunity cost, offering the full market range in every hour may expose the market participant to mitigation and suboptimal dispatch.

2 | Alternatives: PJM's preferred approach proposed above depends on PJM successfully implementing SOC tracking and disallowance of infeasible dispatch. If this is not feasible to implement in a timely manner, PJM could consider the following two alternate approaches in the interim.

(a) **Offer based on ICAP and duration:** PJM could require the ESR to offer their committed ICAP for at least the number of hours equal to its duration. For example, a 10 MW, four-hour battery would be required to offer 10 MW in at least four hours to meet the Must-Offer Requirement. If this option is adopted, PJM proposes to permit the market participant to determine in which hours the offer is made. PJM does not recommend specifying the hours in which an energy offer must be made. First, doing so introduces additional complexity as the hours would have to be determined and posted ahead of the DA offer period in order to facilitate compliance. Second, depending on how often the hours are updated, they may incorrectly represent the hours of greatest need for a specific operating day. Finally, such specificity is likely not necessary given that, as profit maximizing entities, battery storage is inherently incentivized to seek dispatch during the highest price hours, and the highest price hours are likely to reflect the hours of greatest operational need.

(b) **Offer based on the asset's energy capability:** PJM could require ESRs to offer an energy quantity that, over 24 hours, equals its total energy capacity, based on the battery's ICAP and duration. For example, a 10 MW, four-hour battery would be required to offer at least 40 MWh of energy in the DA market to meet the Must-Offer Requirement. Such a requirement would effectively mirror PJM rules for hybrid resources. Hybrids are required to offer, over 24 hours, an energy quantity that at least equals the intermittent component's forecasted output. This requirement is based on the idea that the hybrid's battery component will have access to at least the amount of energy generated by the intermittent component during a 24-hour period. However, based on the charge and discharge patterns, the energy offered in each hour may not reflect the intermittent output. Such a requirement would provide the market participant with the most flexibility to optimize the battery's operation. Meanwhile, PJM would see energy offers for the full megawatt-hour capability of the resource. Moreover, it would reduce (though not eliminate) instances whereby the resource's dispatchable range does not accurately reflect its capability and more closely align with PJM's existing Tariff provision that the resource's offered hourly megawatt quantity may vary hour to hour from the capacity commitment.

If option 1 is not feasible in the near term due to a lack of state of charge tracking, PJM recommends adoption option 2b in the interim. This option would require ESR to offer in their full energy capability over the full 24-hour day. Notably, this option would also allow ESRs to meet their energy must offer by offering in their full megawatt output capability in the number of hours equal to their duration (as described in option 2a) but would provide additional flexibility to market participants while still guaranteeing that the resources' full capability is available to the market.

IV. Complementary Efforts

A. Reserve Certainty Senior Task Force

Today, most batteries participating in PJM's markets are regulation-only resources. Batteries comprised 28.0% and 26.7% of PJM's regulation fleet in 2023 and 2024 respectively.[22] By contrast, PJM has very minimal battery participation in its reserve markets. The Regulation Market is unlikely to drive much future energy storage investment. However, the increasing levels of solar energy resources in the PJM footprint coupled with reserve market reforms, which are being proposed through the Reserve Certainty Senior Task Force (RCSTF), present new opportunities for energy storage participation in PJM's reserve markets. To realize these opportunities and to ensure that battery energy storage participation leads to greater market efficiency, there are several challenges that will need to be tackled, many of which have already become apparent in other regions that have greater participation from energy storage resources in their energy and ancillary markets.

The complete details of the PJM proposal in RCSTF can be found in PJM's Position on Challenges and Solutions for Long-Term Reserve Certainty Reforms (PDF) and the supporting documents referenced therein.[23]

Lost Opportunity Costs for Limited Duration Resources in Providing Reserves

Provided that energy storage resources can reflect their lost opportunity costs in their energy bids, the primary risk of energy storage resources experiencing lost opportunity costs will come from the uneconomic deployment of reserves. This could occur when an energy storage resource is asked to stop charging or to discharge earlier than it otherwise would to convert reserves into energy. This phenomenon occurs with the deployment of Synchronized Reserves because it is deployed during an event without reference to resource energy offers. PJM's other existing and proposed reserve products are deployed economically, so this is not a concern for those reserve products.

Reserve Energy Endurance Limitations

In PJM's existing reserve market design, the only explicit energy endurance requirement placed on resources holding a reserve assignment is the expectation that resources with a Synchronized Reserve assignment can sustain their response when deployed for at least 30 minutes. This is not evaluated in the provisioning of Synchronized Reserves today but is enforced through PJM's evaluation of resource performance during Synchronized Reserve Events. While 30 minutes is a reasonable energy endurance expectation for Synchronized Reserves that must respond quickly and for a limited time during an emergency event, greater energy endurance is needed from operating reserves that are expected to come online to serve load during peak times and to unload and backfill Synchronized Reserves following an event. The lack of energy endurance in ERCOT's ancillary services was an operational challenge that emerged in that region causing them to enter escalating emergency procedures during summer months. Since then, ERCOT has introduced a four-hour duration requirement for its non-spinning reserve service.[24]

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[22] 2024 State of the Market Report for PJM, Section 10 – Ancillary Service Markets, Monitoring Analytics, March 13, 2025
[23] The position paper and the supporting documents are on the RCSTF page.
[24] AS Duration Under RTC: ERCOT Recommendations

Proposed Path Forward

1 | **Allow resources to bid their risk of revenue loss into their reserve offers.** For Synchronized Reserves, which are deployed uneconomically during an event, PJM proposes to allow resources to reflect their risk of incurring lost opportunity costs during deployment as part of their Synchronized Reserve offers. This is something that is currently being discussed in the RCSTF. If that work is not successful, other approaches could be pursued, such as designing make-whole payment rules to cover these costs.

2 | **Unnest reserve products.** As more energy-limited resources enter the PJM system, it will be important that PJM recognize the value that resources with energy endurance provide in ensuring energy adequacy. This becomes a second dimension in the valuation of reserve services, and it is likely that energy endurance may not always be provided by the same resources that can provide fast response, which has to date been the sole determinant of reserve quality. To recognize these two dimensions, PJM proposes an unnested construct for its reserve products to eliminate the unidimensional assumption of reserve quality solely as a function of flexibility or speed of response. This is actively being discussed in the RCSTF.

3 | **Define appropriate energy endurance requirements for all reserve products.** Once its reserve products are unnested, PJM will need to define appropriate energy endurance (or duration) requirements for all its reserve products. These requirements should be rightsized to provide the needed reliability value without over-constraining market outcomes and stranding energy. This topic is also being discussed in RCSTF. If PJM is unsuccessful in unnesting its existing reserve products, this will limit PJM's flexibility in defining reserve product energy endurance requirements. However, even in this event, PJM will still need to have energy endurance requirements for its reserves. In this case, it is likely that PJM will need to be more conservative in setting the single requirement for all nested products to maintain reliability, which could lead to inefficient market outcomes and unduly restrict energy storage participation in PJM's reserve markets.

Appendix A: Numerical Analysis of the Opportunity Cost Cap Methodologies

Purpose

This appendix presents simulation results on the effectiveness of the different opportunity cost (OC) cap methodologies described in this position paper for a profit-maximizing energy storage resource (ESR) with perfect foresight of prices. We consider the optimal scheduling of hypothetical four-hour and 12-hour ESRs with no maintenance or degradation costs located in different PJM zones, over a two-year optimization horizon (April 2024 through April 2026).

Preliminaries

This section provides the terminology for ESR optimization and describes the approach for evaluating the different OC cap methodologies.

ESR Optimization Formulation

Let $x(t)$ denote the state of charge (SOC) in megawatt-hours, and $u(t)$ denote the power schedule in megawatts of the ESR at time t; $u(t)$ is defined to be positive when the ESR is discharging and negative when the ESR is charging. The SOC dynamics are given by:

$$x(t+1) = \alpha \times x(t) - \beta \times u(t), \tag{1}$$

where α and β are non-negative scalars.

The SOC and power bounds are given by:

$$x(t) \in [0, C], \qquad u(t) \in [-P_c, P_d], \tag{2}$$

where $C > 0$ is the SOC capacity limit (in megawatt-hours), $P_c > 0$ is the charging power limit (in megawatts), and $P_d > 0$ is the discharging power limit (in megawatts) of the ESR.

Let ρ_t denote the real-time locational marginal price (LMP) at the ESR node, T the optimization horizon, and Δ_t the length of each interval in units of hours (e.g., for a 5-minute interval, $\Delta_t = 1/12$). The profit-maximizing ESR is assumed to have perfect foresight of ρ_t over the horizon T. The profit maximization of the ESR is expressed as a linear program with $x(t)$ and $u(t)$ as the optimization variables:

$$\max \sum_{t=0}^{T-1} \Delta_t \times \rho_t \times u(t), \tag{3}$$

subject to the constraints (1) and (2), and the initial SOC $x(0)$.

Let $\lambda(t+1)$ denote the co-state variable: i.e., the dual variable corresponding to (1), and let $\lambda^*(t+1)$ denote the corresponding optimizer. Further, let $u^*(t)$ denote the optimal power schedule. Using Pontryagin's Maximum Principle, we can infer that $u^*(t) = -P_c$ when the ESR is charging, $u^*(t) = P_d$ when discharging, and $u^*(t) = 0$ otherwise; moreover, the ESR will discharge when

$$\rho_t > \frac{\beta}{\Delta_t} \times \lambda^*(t+1), \tag{4}$$

and charge when

$$\rho_t < \frac{\beta}{\Delta_t} \times \lambda^*(t+1) \tag{5}$$

Evaluation of OC Cap Methodologies

We evaluate the performance of the following OC cap methodologies:

1 | OC cap is set as maximum day-ahead (DA) LMP. This is PJM's proposed approach discussed above.

2 | OC cap is set as 1.1 times the N^{th}-highest DA LMP, where N is the duration of the ESR. For example, the OC cap will be 1.1 times the fourth-highest DA LMP for a four-hour duration ESR. This methodology is used by California Independent System Operator for setting the default energy bid (DEB) of an ESR.

3 | OC cap is set as 1.1 times the average of the top N DA LMP hours, where N is the duration of the ESR. For example, the OC cap will be 1.1 times the average of the top 4 DA LMP hours for a four-hour duration ESR. This is intended to encompass more of the highest-priced hours in the cost offer calculation as PJM's cost offer serves as a cap, rather than a default bid.

To evaluate the performance of the OC cap methodologies, we calculate the percentage of intervals over the optimization horizon in which the OC cap will force the ESR to discharge (i.e., the OC cap is less than RT LMP) even though the optimal power schedule has the battery charging or doing neither; these are the intervals in which the OC cap is insufficient.

Simulation Results

First, we introduce the parameters of the hypothetical ESRs. The ESRs are assumed to have no SOC leakage and have 100% efficiency. Consequently, $\alpha = 1$ and $\beta = \Delta_t = 1/12$ (i.e., the 5-minute interval represented in hourly units). Moreover, the ESR is assumed to have symmetric charge and discharge limits: $P_c = P_d = 1\ MW$. This implies that a four-hour duration ESR will have a SOC limit $C = 4\ MWh$, while a 12-hour duration ESR will have a SOC limit $C = 12\ MWh$. Finally, for the four-hour duration ESR, the initial SOC is set to be 2 MWh, while for the 12-hour duration ESR, the initial SOC is set to be 6 MWh.

We consider three pricing scenarios for each type (four- or 12-hour duration) of ESR:

1 | ESR is subject to aggregated zonal LMP from the Dominion zone (DOM).

2 | ESR is subject to aggregated zonal LMP from the COMED zone.

3 | ESR is subject to aggregated zonal LMP from the PSEG zone.

The ESRs optimize for each 5-minute interval from April 30, 2024, through April 28, 2026, assuming perfect foresight of LMPs over the two-year optimization horizon. **Table 5** summarizes the simulation results evaluating the three OC cap methodologies for four-hour and 12-hour duration ESRs under the four pricing scenarios. The percentage of intervals in the optimization horizon for which the OC Cap Methodology would have forced the ESR to discharge instead of charge or maintaining SOC based on the optimal power schedule are shown.

Table 5. Simulation Results for the Three OC Cap Methodologies.

April 30, 2024, to April 28, 2026		% of Failed Intervals in OC Cap Methodology		
Zone/Node	**ESR Duration**	**Max DALMP**	**1.1*Nth Highest DALMP**	**1.1*Avg DALMP**
DOM	4h	0.25	0.32	0.25
COMED	4h	0.19	0.33	0.18
PSEG	4h	0.03	0.1	0.02
DOM	12h	0.07	0.45	0.09
COMED	12h	0.13	1.93	0.31
PSEG	12h	0.01	0.47	0.02

We can see that the 1.1*Nth Highest DALMP methodology has the highest failure rate across all scenarios for both types of ESRs. For the four-hour-duration ESR, the OC cap methodologies A (Max DA LMP) and C (1.1 times average DA LMP) have similar performance: the OC cap in both methodologies is sufficient in more than 99.75% of the intervals. For a 12-hour duration, we can see that the methodology A (Max DA LMP) has the best performance, with the OC cap being sufficient in more than 99.87% of the intervals. We further performed the same analysis using the nodal LMP (rather than a zonal aggregate) for a pnode on the PJM system corresponding to an existing ESR unit. The results were similar, indicating that the zonal aggregate was not obfuscating greater price variation in the examined location.