

Enabling Full and Fair Participation of Utility-Controlled Distributed Battery Storage

Base Power Company Comments on the Maine DOER Draft RFP for Energy Storage Projects
(35-A M.R.S. §10313) | April 20, 2026

Contents

Section I: Five Points of Clarification and Recommendation

- 1.1: Interconnection: The Capacity Capability Interconnection Standard (CCIS) Requirement Closes the Door §3.2.5 Opened
- 1.2: Aggregation and Site Control: Designed for Single-Site Projects Only
- 1.3: Dispatch Rights: RFP Assumes Developer Control, But Utilities Have Asked for Dispatch Control
- 1.4: Payment Formula: No Floor of Zero and EMA Basis Risk
- 1.5: T&D Value: Listed as a Criterion with No Defined Methodology

Section II: Storage RFP Design Best Practices

Part 1: Eligibility Requirements

- 2.1: Permit Distribution-Level Interconnection
- 2.2: Allow Resource Aggregation to Meet Size and Performance Requirements
- 2.3: Adapt Site Control Requirements for Distributed Deployments
- 2.4: Allow Flexible Ownership and Contract Structures

Part 2: Evaluation Criteria

- 3.1: Quantify and Score Avoided T&D Costs
 - 3.2: Reward Deployment in Constrained Areas and low-to-moderate income (LMI) Communities
 - 3.3: Fully Credit Dispatch Flexibility and Availability
 - 3.4: Score Earlier Commercial Operation Dates
 - 3.5: Ensure Qualitative Criteria Don't Penalize Newer Resource Classes
-

Base Power Company submits these comments in response to the Maine Department of Energy Resources (DOER) Draft RFP for Energy Storage Projects, published March 27, 2026, with public comments due April 20, 2026. We participated in the April 16 public information session and have reviewed the draft in detail.

Base Power operates aggregated fleets of residential battery storage dispatched as utility-controlled virtual power plants. As a recent example, we have contracted 100 MW of utility-controlled distributed battery storage with CoServ Electric in Texas, a commercially proven model ready to deploy at scale. The Best Practices document in Section II reflects our perspectives and recommendations based on our experience across multiple utility procurement processes.

We respectfully request clarification on five areas before the final RFP is issued. For each, we identify the specific draft provision, the question it raises for distributed utility-controlled storage, and our recommendation. Section II provides the broader design principles that inform these recommendations.

Section I

Five Points of Clarification and Recommendation

1.1 Interconnection: The CCIS Requirement Closes the Door §3.2.5 Opened

Section 3.2.5 explicitly accommodates distribution-connected projects, defining the Delivery Point as the ISO-NE P-node representing the project's injection point onto the Pool Transmission Facility (PTF). This is a constructive signal. However, the same section requires all bidders to hold a CCIS agreement, be active in the ISO-NE Transitional Cluster Study, or plan to submit an interconnection request for Capacity Network Resource service in the 2026 Cluster Request Entry Window. All three paths require transmission-level Capacity Network Resource Interconnection Service (CNRIS) status. Distribution-connected resources interconnect under the applicable distribution tariff (Small Generator Interconnection Procedures filed with the Maine PUC), a separate process that does not produce CCIS eligibility. The delivery point language opens a door that the interconnection requirement then closes.

We recommend DOER:

- Create a distribution interconnection eligibility path: accept a signed interconnection agreement with CMP or Versant Power under their applicable distribution tariff (Small Generator Interconnection Procedures filed with the Maine PUC) as satisfying §3.2.5, with the bidder demonstrating that its injection point maps to an ISO-NE P-node for dispatch and settlement.
- Define "Delivery Point" to include load substations on the distribution system, enabling aggregated distributed resources to be represented at a nodal delivery point. ERCOT's Aggregate Distributed Energy Resource (ADER) program is an established framework for this.
- State any minimum resource size requirement as a technology-neutral performance criterion at the aggregated bid level, not as a queue-status proxy.

1.2 Aggregation and Site Control: Designed for Single-Site Projects Only

The draft RFP does not address whether bidders may aggregate multiple distributed units to meet the 3 MW minimum threshold (§3.2.4). The site control requirements (§3.2.3, §5.1.5) require binding property agreements, site plans, deeds, and easements, all of which presuppose a single physical location. A distributed fleet operator enrolling residential customers cannot provide these documents at bid submission. Connecticut's PA 21-53 procurement, which explicitly covers distribution-connected resources, addressed this through post-award deployment milestone structures rather than pre-bid site agreements.

We recommend DOER:

- Confirm that aggregated distributed systems may be bid collectively to meet the 3 MW minimum, with all performance requirements applied at the fleet level.
- Accept demonstrated deployment capability as an alternative to pre-bid site agreements: documented customer acquisition processes, existing waitlists, or a track record of prior fleet deployments in comparable markets.
- Shift site control requirements to post-award milestones with contractual Commercial Operation Date (COD) commitments, rather than requiring binding site agreements at bid submission.

1.3 Dispatch Rights: The RFP Assumes Developer Control, But Utilities Have Asked for Dispatch Control

The draft RFP's structure assumes the developer controls dispatch throughout: the Seller retains all market revenues (§4.2.1), "operates" the resource (§4.1), must serve as Lead Market Participant (§3.2.5), and forecasts market revenues (§3.2.6). There is no provision for utility-directed dispatch or contractual dispatch rights anywhere in the draft.

This conflicts with CMP's and Versant's own positions in Maine PUC Docket 2023-00316 (Report on Utility Control or Ownership of Energy Storage, March 2024), in which both utilities argued they need dispatch control over storage assets for grid stability and reliability. A developer-owns / utility-dispatches model resolves both requirements: the developer holds ISO-NE Locational Marginal Price (LMP) registration and owns the physical assets, while the utility holds contractual dispatch rights and retains operational and market revenues. This structure has established precedent under New York PSC Case 15-E-0751.

We recommend DOER:

- Define and permit a developer-owns / utility-dispatches model in the final RFP: the developer owns the assets and serves as ISO-NE Lead Market Participant for registration purposes, while the utility holds contractual dispatch rights and retains the operational and market value generated by the resource. The developer receives a fixed capacity availability payment. Base Power currently operates under this structure with CoServ Electric (100 MW contracted), and New York PSC Case 15-E-0751 establishes regulatory precedent for it.
- Confirm that the fixed pricing / no-Energy Market Adjustment (EMA) option (§4.2.3) is evaluated on equal terms with the standard pricing option and is not penalized in scoring. For a developer-owns / utility-dispatches structure where the utility retains operational revenues, fixed pricing is the natural and appropriate mechanism.

1.4 Payment Formula: No Floor of Zero and EMA Basis Risk

The Net Monthly Payment formula (Bid Price × Capacity minus Capacity Value minus Energy Market Adjustment) has no floor of zero. If Capacity Value (CV) and EMA together exceed the toll, the developer owes money to the utility. No comparable recent procurement omits this floor (Massachusetts 83E, New York ISCRFP25-1, New Jersey GSESP, Connecticut PA 21-53 all include one). The EMA formula, modeled on the NYSEDA index storage credit as confirmed at the April 16 session, deducts theoretical Day-Ahead arbitrage value regardless of actual dispatch.

Beyond the floor, the EMA formula creates basis risk for any developer regardless of dispatch model. The formula deducts a theoretical optimal Day-Ahead arbitrage value that no real resource can fully capture in practice, due to state-of-charge constraints, degradation, competing dispatch obligations, and market timing. NYSEDA's own Index Storage Credit (ISC) program, on which this EMA is explicitly modeled, has drawn published criticism for exactly this reason: when the reference price systematically overstates achievable revenues, developers are penalized for value the market did not make available to them. This is a structural risk with the formula itself, independent of who controls dispatch.

We recommend DOER:

- Add a floor of zero to the Net Monthly Payment: $\max(0, (\text{Bid Price} \times \text{Capacity}) - \text{CV} - \text{EMA})$.
- Align the EMA with actual achievable revenues: base the formula on realized market revenues rather than a theoretical optimal Day-Ahead spread, consistent with how NYSEDA has been urged to refine the ISC Reference Energy Arbitrage Price (REAP) to reflect real resource operating constraints.
- Publish the complete Net Monthly Payment formula in the RFP body, including all components, sign conventions, and the floor of zero.

1.5 T&D Value: Listed as a Criterion with No Defined Methodology

Deferred and avoided T&D costs are identified as a quantitative benefit (§3.3.2(c)) and a final selection factor (§3.4), but the draft RFP provides no methodology for calculating or comparing this value across

bids. Without a defined methodology, distributed resources cannot demonstrate their primary competitive advantage and evaluators cannot make an apples-to-apples comparison between distributed and transmission-connected proposals. The Governor's Energy Office (GEO)'s December 2024 report found benefit-to-cost ratios of 3 to 5x for distribution-connected storage valued on avoided T&D costs. That value cannot be captured or scored under the current evaluation framework.

We recommend DOER:

- Define a specific avoided T&D cost methodology before issuing the final RFP, such as E3's Avoided Cost Calculator or the Brattle Group's documented range of \$20 to \$30/kW-yr from utility regulatory filings, and publish it with sufficient lead time for bidders to optimize proposals.
- Publish CMP's and Versant Power's distribution planning data identifying constrained circuits and substation deferral candidates, enabling bidders to propose targeted deployments and evaluators to score locational value objectively.
- Provide a timeline for the feeder-level investigation and the separate 40 MW distribution-connected procurement recommended by the GEO in December 2024. That investigation has not been initiated and was not referenced at the April 16 public information session.

Section II

Storage RFP Design Best Practices

Enabling Full and Fair Participation of Utility-Controlled Distributed Battery Storage

Aggregated, distribution-connected battery storage represents a growing class of grid resources that can deliver capacity, flexibility, and resiliency value to electric utilities. Unlike traditional transmission-connected utility-scale storage, these resources consist of fleets of smaller batteries deployed on the distribution system, often at residential or commercial customer sites, and dispatched as a unified, utility-controlled resource.

As utilities design all-source competitive procurements, RFP requirements and evaluation frameworks often inadvertently exclude or disadvantage this resource class. This memo outlines best practices across two areas: (1) eligibility requirements that enable distribution-connected storage to participate, and (2) evaluation criteria that capture its full system value.

Area	Key Recommendation	Priority
Interconnection point	Permit distribution-level interconnection, not just transmission	Priority 1
Resource aggregation	Allow aggregated fleets to meet minimum MW thresholds	Priority 1
Dispatchability	Evaluate utility-controlled, 24/7 dispatchable DERs as a separate resource class from voluntary demand response	Priority 1
Site control	Allow distributed resources to demonstrate deployment ability rather than pre-bid site agreements	Priority 1
T&D value	Quantify and score avoided transmission and distribution costs	Priority 1
Performance requirements	Define requirements at the aggregation level	Priority 2
Ownership structure	Permit utility-ownership and build-transfer models for distributed assets	Priority 2
Locational value	Reward deployment in constrained areas or areas with local resiliency needs	Priority 2
Commissioning timeline	Score earlier commercial operation dates	Priority 2

Part 1: Eligibility Requirements

RFPs should evaluate resources on their ability to meet performance requirements, not on where they connect to the grid or how many physical units comprise them. The following practices ensure distribution-connected storage can participate on a level playing field.

2.1 Permit Distribution-Level Interconnection

Many RFPs limit eligible resources to transmission-connected assets, often as a simplification measure. For instance, RFPs often require bids to be in the generation interconnection queue as a basic eligibility criterion. This constraint excludes distributed resources, which can bypass interconnection queues. Utilities should:

- Explicitly allow resources that interconnect to the distribution system to participate, or issue a separate distribution-connected storage track within the same RFP.
- If transmission-only requirements are retained, state the underlying reason (e.g., minimum resource size, dispatch complexity) and translate that rationale into technology-neutral performance criteria, so distribution-connected resources that satisfy those criteria remain eligible.
- Define the “Point of Delivery” to include bulk system load substations on the distribution system, enabling aggregations to be mapped to a nodal or substation-level point for dispatch purposes. ERCOT’s Aggregate Distributed Energy Resource (ADER) program offers a proven framework for this.

2.2 Allow Resource Aggregation to Meet Size and Performance Requirements

Minimum MW thresholds are reasonable for managing procurement complexity, but should be applied at the aggregation level rather than per individual unit. Recommended practices:

- Permit bidders to aggregate multiple distribution-connected systems, potentially across several substations, to meet minimum nameplate capacity requirements.
- Define all performance requirements (ramp rate, availability, emergency limits, telemetry) at the aggregated resource level, with the bidder contractually responsible for ensuring the fleet meets them in aggregate.
- Require revenue-grade metering (e.g., ANSI 12) at the inverter level for each individual site, with device-level telemetry at intervals sufficient for dispatch control (typically 1 to 60 seconds).

2.3 Adapt Site Control Requirements for Distributed Deployments

Standard site control requirements are designed for single-site projects and do not translate well to distributed fleets, which may involve thousands of customer agreements acquired after contract award. Utilities should:

- Accept demonstrated deployment capability (documented customer acquisition processes, existing waitlist data, or track record of prior deployments in comparable markets) as a proxy for site control.
- Allow bidders without completed site agreements to provide a detailed plan for achieving site control within required timelines, with evidence from prior deployments.
- For interconnection, allow bidders to submit a detailed interconnection plan and evidence of typical approval timelines in lieu of completed System Impact Studies or signed agreements, provided the plan demonstrates no material risk to the commercial operation date.

2.4 Allow Flexible Ownership and Contract Structures

Limiting procurements to a single contract structure can unnecessarily restrict the pool of eligible resources. Utilities should:

- Permit both power purchase agreement (PPA) and utility-ownership / build-transfer structures, allowing the utility to evaluate which model is most cost-effective given applicable tax incentives and O&M considerations.

Part 2: Evaluation Criteria

Even when distribution-connected storage is technically eligible, evaluation frameworks that score only transmission-level value will systematically undervalue it. The following practices ensure evaluation reflects the full system benefit of distribution-connected resources.

3.1 Quantify and Score Avoided Transmission & Distribution Costs

Distribution-connected storage provides system value beyond capacity and energy. It can defer or avoid transmission and distribution infrastructure upgrades by relieving local congestion. This value should be reflected in RFP scoring:

- In the valuation methodology, assess and include the value for estimated avoided T&D costs attributable to distributed resources. Several utility examples:
 - Avista's 2025 IRP ascribes avoided T&D value to distributed resources (IRP page 54).
 - E3's Avoided Cost Calculator is utilized by California IOUs to quantify avoided T&D costs on a locational basis.
 - Brattle Group research documents avoided T&D benefits from utility regulatory filings across the country, largely falling in the range of \$20 to \$30/kW-yr.

3.2 Reward Deployment in Constrained Areas and LMI Communities

Aggregated distributed storage can be deployed with geographic precision, targeting specific feeders or substations where capacity or reliability needs are most acute. RFPs can leverage this capability by:

- Including scoring criteria that reward deployment in identified constrained areas, high-outage feeders, or substations where planning teams have documented local capacity needs, as often highlighted in integrated resource plans and long-term T&D plans.
- Creating optional targeted deployment tracks or carve-outs within the RFP, allowing bidders to propose resources sized to address a specific local constraint.
- Considering low-to-moderate income (LMI) community deployment as a scored criterion, where distributed storage can be deployed at no cost to eligible customers while providing grid services.
- Considering broader socioeconomic benefits such as local job growth to support warehousing and installation of distributed storage fleets.

3.3 Fully Credit Dispatch Flexibility and Availability

Distribution-connected storage that is fully utility-dispatchable (available 24/7 for real-time dispatch including both charge and discharge) provides materially more value than resources with limited dispatch windows. Evaluation should:

- Distinguish between resources that are fully dispatchable on a 24/7 basis (including real-time economic dispatch signals) and those that are available only for limited event-based calls.
- Score or apply a bid adjustment that reflects the incremental value of continuous availability, consistent with how the utility values this attribute in its integrated resource plan.

- Require bidders to specify expected discharge duration and confirm performance at the offered duration level, ensuring duration commitments are comparable across resource types.

3.4 Score Earlier Commercial Operation Dates

Distributed storage fleets can achieve commercial operation faster than transmission-connected resources due to streamlined interconnection and site acquisition processes. Earlier in-service dates provide immediate value to ratepayers and support resource adequacy targets. Utilities should:

- Include commissioning timeline as an explicit scoring criterion, rewarding bidders who can achieve commercial operation earlier within the RFP's required window.
- Avoid penalizing bidders who have not yet completed interconnection or site control at the time of bid, provided they demonstrate a credible, low-risk path to timely commercial operation.

3.5 Ensure Qualitative Scoring Criteria Do Not Inadvertently Penalize Newer Resource Classes

Qualitative scoring rubrics designed for traditional resources can unintentionally disadvantage aggregated distributed storage. Utilities should review scoring criteria to ensure:

- Technology maturity assessments reflect demonstrated performance records at the aggregation level, rather than requiring multi-decade operating histories for individual units.
- Criteria related to contractor or subcontractor structure are adapted to reflect vertically-integrated distributed resource operators, who may not rely on subcontractors in the same way as traditional project developers.
- Project development criteria (e.g., permitting, financing, equipment procurement) are adapted to reflect the development timeline of distributed fleets rather than single-site utility-scale projects.

Base Power Company welcomes the opportunity to discuss these recommendations with DOER, CMP, and Versant Power staff. We participated in the April 16, 2026 public information session and are available to provide technical briefings on any aspect of this submission.