Maine Department of Energy Resources
22 State House Station
Augusta, Maine 04333

April 20, 2026

Re: Draft Request for Proposals for Energy Storage Projects Pursuant to 35-A M.R.S. §10313

To Whom It May Concern:

Longroad Development Company, LLC ("Longroad") appreciates the opportunity to provide comments on the Maine Department of Energy Resources ("Department") draft Request for Proposals for Energy Storage Projects pursuant to 35-A M.R.S. §10313 ("Draft RFP").

Longroad supports Maine's efforts to procure energy storage resources that provide net benefits to Maine ratepayers and advance the objectives set forth in §10313 and the Maine Energy Plan. The Draft RFP contemplates procuring approximately 200–300 MW of new energy storage projects through Energy Storage Contracts with Central Maine Power Company and/or Versant Power, subject to review and approval by the Maine Public Utilities Commission ("Commission"), in support of Maine's statutory goal of 400 MW of energy storage installed in the state by 2030.

Longroad is a Boston-based renewable energy company with a deep track record developing, owning, and operating utility-scale renewable generation and battery energy storage projects across the United States, with a strong presence in Maine and New England. Since its founding, Longroad has developed more than 6 GW of utility-scale renewable projects nationwide and currently has over 3.2 GWh of battery storage either operational or under construction, demonstrating extensive experience delivering energy storage projects through development, construction, financing, and long-term operations.

Longroad's Maine experience is unmatched. Over the past two decades – at Longroad and previously at First Wind – the team has developed 676 MW of Maine's 1,217 MW of operating wind capacity. Most recently, Longroad completed the 152 MWdc Three Corners Solar project in Kennebec County in 2024, the largest solar project in New England.

Through its subsidiary Longroad Energy Services ("LES"), the company operates and manages 6.9 GW of wind, solar, and storage projects nationwide from its 24/7 remote operations center in Scarborough, Maine underscoring our long-term commitment to Maine and our capability to reliably deliver and operate large-scale energy storage assets.

We offer these comments for the Department's consideration in the spirit of designing a successful energy storage procurement.

1. Capacity Value

a. Integrate Capacity Value deduction into total contract payments

The Capacity Value deduction is described in Section 4.2.1 of the Draft RFP, while Appendix C specifies what appears to be net contract payments, but does include the Capacity Value deduction. For clarity, we recommend showing the total net contract payments, including the fixed price payments, Energy Market Adjustment and Capacity Value deduction in Appendix C or elsewhere in one place in the RFP.

b. Apply Capacity Value deduction regardless of whether projects qualify for capacity

We recommend clarifying that the Capacity Value deduction applies to all projects, including those that do not qualify for the ISO-NE capacity market due to a transmission limitation or for another reason. As drafted, the Capacity Value provision could be read as using zero capacity for projects not qualifying for capacity (as they may have no accredited capacity), which would effectively eliminate the Capacity Value deduction for such projects and have a negative effect on the ratepayer value. For projects that do not qualify for capacity, the volume in the Capacity Value formula should be based on the estimated amount of accredited capacity the project would have received based on its duration and other characteristics if it did qualify.

c. Use actual accredited capacity for projects that qualify

On the other hand, if a project does qualify for capacity, we recommend using the actual accredited capacity of the project for the volume in the Capacity Value formula. This can be important if ISO-NE assigns accredited capacity for storage projects that qualify for capacity not only based on their size and duration, but also taking into account other project characteristics. Using the actual accredited capacity would reduce the residual risk for projects, which should translate into a lower cost for the ratepayers. (Also, a simpler notation than “rMRIProxy” can make the Capacity Value formula look more intuitive.)

d. Net capacity performance penalties for extended scarcity events

While storage projects can be expected to perform (discharge) for their duration during capacity scarcity events, it would be unreasonable to expect a storage project to perform beyond its duration in case of a scarcity event extending for longer than the storage project duration. While such events are unlikely, they can result in high performance penalties for projects, so we recommend netting from the Capacity Value capacity performance penalties associated with parts of scarcity events that extend beyond duration of the storage projects.

e. Clarify applicable capacity clearing price

Same as in the current ISO-NE capacity market structure, in the future a single delivery period may be subject to multiple sequential capacity auctions, and a given capacity auction can produce multiple clearing prices for different parts of the ISO-NE system. The Capacity Value provision does not specify which capacity clearing price will be used in such circumstances. We recommend clarifying in the RFP that the Capacity Value calculation will use the capacity auction clearing price that is (a) for the capacity zone where the project is located, and (b) from the first ISO-NE capacity auction for any delivery period that includes the settlement month.

2. Energy Market Adjustment

a. Consider physical toll contract structure

The lowest cost to ratepayers is usually achieved with contract structures that minimize residual risks to projects relative to fixed-price contract payments, as such structures result in the lowest risk premiums in contract pricing offered by project developers. In the case of storage projects, such contract structure is a physical toll agreement, where a buyer utility controls the dispatch of the storage project and receives all products produced by the project including energy arbitrage value, capacity, ancillary services and other attributes in exchange for fixed-price capacity payments. Physical tolls are used in utility storage procurements across the country and represent the most common contract structure for energy storage offtake. We encourage the Department to consider the physical toll structure instead of the proposed financially settled one, if that is possible at this stage. If that is deemed not possible, we recommend minimizing residual risks resulting from a financially settled structure as further described below.

b. Use nodal instead of zonal energy settlement

The Energy Market Adjustment ("EMA") is based on prices for a load zone rather than project pricing nodes, which creates a basis risk for projects, and as noted above, should translate into higher contract prices and cost for ratepayers. While zonal pricing may be used in NYSERDA contract structures, settlement at the project node is common in financially settled storage contracts elsewhere (for example, storage contracts signed by SCE and PG&E in California), and the basis risk has been one of the reasons for limited interest in NYSERDA procurements expressed by project developers. We recommend changing the EMA to use prices at the project nodes instead of a load zone.

c. Refine charging cost calculation

The cost of storage charging is accounted in the EMA by using X lowest hourly prices of the day divided by the round-trip efficiency, where X is the storage duration in hours. While an RTE adjustment is appropriate, that calculation doesn't accurately reflect the cost of storage charging. For example, a 4-hour storage with an 86% RTE may require charging during the 4 lowest price hours + 65% of the 5th lowest price hour (as 4 / 0.86 = 4.65), but cannot be charged for 116% (1 / 0.86 = 1.16) of each of the 4 lowest price hours as implied by the EMA calculation. It is relatively easy to modify the EMA formulas to reflect charging during more than X hours instead of higher than a 100% volume in X hours, as for example is done in financially settled storage contracts signed by SCE and PG&E in California. We recommend making this revision for the EMA to reduce the resulting residual risk for the projects.

d. Keep day-ahead settlement

We support settling the EMA based on day-ahead prices, as proposed in the Draft RFP. While a storage project can participate in both day-ahead and real-time markets, real-time prices are highly unpredictable, so using real-time prices in a simple EMA settlement can grossly overestimate the value that can be realized by a storage project in the energy market and necessitate a high risk premium.

e. Clean up the language

The EMA language may require some cleanup for clarity. For example, “nth highest price hour” should be replaced with something like “nth highest hourly price of the day”, with a similar revision for the lowest prices. Also, units for the prices should be specified, and if the project capacity BC is expressed in kW while the prices are in $/MWh, BC should be divided by 1000 in the daily EMA formula.

3. Contract Term

We support allowing terms up to 20 years and the requirement that each bidder submit at least one 20-year offer. We recommend clarifying the evaluation treatment of any shorter-term, mutually exclusive alternatives to ensure bidders can provide optionality without penalty (Draft RFP Section 4.6).

4. Bid Fee

We recommend the Department evaluate whether the proposed $750 per megawatt base bid fee is appropriately scaled for a first procurement under §10313 (Draft RFP Section 5.4).

5. Standard Form Contract

The contract terms – including EMA and Capacity Value calculations, conditions precedent, termination rights and security requirements – are central to project economics and financing, and affect required contract pricing and the likelihood of a successful procurement. We recommend the Department release a draft of the Standard Form Contract and solicit comments on that sufficiently early so that such comments can be addressed in the final form contract, which should be made available no later than 30 days before the RFP bids are due.

6. Commission Review

Longroad supports the 120-day Commission review timeline established by LD 1270 (35-A M.R.S. §10313(2)(C)) and encourages the Department to refrain from requesting a longer review period and to structure the solicitation timeline accordingly.

Concluding Remarks

Longroad appreciates the opportunity to provide comments on the Department's Draft RFP for energy storage projects pursuant to 35-A M.R.S. § 10313. We are committed to working constructively with the Department, the Commission, and other stakeholders to make this procurement a success, and welcome continued engagement as the Department finalizes the solicitation and standard form Energy Storage Contract. We are happy to discuss any of these recommendations in further detail at the Department's convenience.

Sincerely,

Longroad Development Company