Maine Governor's Energy Office
Opportunity for Comment
Maine Energy Storage Program Development Pursuant to P.L. 2023, ch. 374

Issue Date: March 12, 2024
Subject: Opportunity for Comment Regarding Draft Assessment of Storage Procurement Mechanisms and Cost-effectiveness in Maine
Response Due Date: March 25, 2024
Submit Responses To: caroline.colan@maine.gov

Description

This is an Opportunity for Comment issued by the Governor's Energy Office (GEO). The GEO, established within the Executive Department and directly responsible to the Governor, is the designated state energy office tasked with a wide range of activities relating to state energy policies, planning, and development.

This Opportunity for Comment seeks public input to inform the GEO's implementation of section 2 of Public Law 2023, chapter 374, *An Act Relating to Energy Storage and the State's Energy Goals* (LD 1850), which was signed into law by Governor Janet Mills on June 30, 2023. This legislation builds upon the state's existing energy storage goals and makes clear Maine's intention to invest in energy storage infrastructure to increase grid reliability and support the integration of clean energy resources needed to meet the state's climate and clean energy goals in a cost-effective manner.

Section 2 of this legislation directs the GEO to evaluate designs for a program to procure up to 200 megawatts of commercially available utility-scale energy storage systems connected to the transmission and distribution systems. Energy storage is defined in Maine statute as 'a commercially available technology that uses mechanical, chemical or thermal processes for absorbing energy and storing it for a period of time for use at a later time'.[1]

In evaluating programs for the procurement of energy storage systems, the GEO shall consider programs that are likely to be cost-effective for ratepayers and that are likely to achieve the following objectives:

A. Advance both the State's climate and clean energy goals and the state energy storage policy goals established in Title 35-A, section 3145 through the development of up to 200 megawatts of incremental energy storage capacity located in the State;
B. Provide one or more net benefits to the electric grid and to ratepayers, including, but not limited to, improved reliability, improved resiliency and incremental delivery of renewable electricity to customers;
C. Maximize the value of federal incentives; and

[1] 38 M.R.S. §2481.

D. Enable the highest value energy storage projects, specifically energy storage systems in preferred locations, projects that can serve as an alternative to upgrades of the existing transmission system and projects of optimal duration.

The GEO issued a Request for Information Regarding the Development of the Maine Energy Storage Program Pursuant to P.L. 2023, ch. 374 (the RFI) on November 13, 2023.[2] Eighteen entities responded to the RFI with information that informed the GEO and its consultants in the development of the attached Draft Assessment of Storage Procurement Mechanisms and Cost-effectiveness in Maine. The GEO is grateful for the information and recommendations provided in response to the RFI.

The intent of this Opportunity for Comment is to obtain additional public input regarding the GEO's evaluation of program designs and consideration of key program objectives. The GEO shall complete the evaluation required by law and provide its recommendations to the Public Utilities Commission (Commission) for a program to procure up to 200 megawatts of energy storage capacity. The Commission shall review the recommendations and determine whether the program recommended by the GEO is reasonably likely to achieve the objectives established by the law. Upon finding the proposed program reasonably likely to achieve those objectives, the Commission shall take steps to implement the program.

Opportunity for Comment

1. Comment on the attached Draft Assessment of Storage Procurement Mechanisms and Cost-effectiveness in Maine prepared by Synapse Energy Economics and Sustainable Energy Advantage, LLC dated March 12, 2024. Comments regarding the methodology, assumptions, and implications for program design are encouraged.
2. P.L. 2023 ch. 374 §2 sub-§1 (A) states in part that the energy storage program must be likely to achieve "the development of up to 200 megawatts of incremental energy storage capacity."
    a. How should the GEO consider the allocation of up to 200 megawatts of incremental energy storage capacity, e.g. between energy storage systems connected to the transmission system or the distribution system?
    b. Comment on the interplay between such allocations, if any, and the objectives established for the program in P.L. 2023 ch. 374 §2.
    c. Should any capacity be reserved for pilot programs or novel applications of commercially available technologies?

Use

Information collected from this Opportunity for Comment will be used by the GEO to inform the fulfillment of requirements under the Act, including the design of the Maine Energy Storage Program.

This is an Opportunity for Comment only. The GEO will not pay for information provided in response, and no project will be supported as a result of this Opportunity for Comment. This Opportunity for Comment is not accepting applications for financial assistance or financial incentives. The Commission may ultimately implement a program recommended by the GEO that is based on consideration of the input received from this Opportunity for Comment, as well as the RFI. ***The GEO may publish responses to this Opportunity for***

[2] The RFI and all submitted responses are available online at https://www.maine.gov/energy/studies-reports-working-groups/current-studies-working-groups/storage-procurement-study-1850

Comment on its website. All responses to this Opportunity for Comment may be subject to the State of Maine Freedom of Access Act, thus sensitive or confidential business information should not be provided in response to this Request.

DRAFT

Assessment of Storage Procurement Mechanisms and Cost-effectiveness in Maine

Draft report prepared pursuant to P.L. 2023 Chapter 374

Prepared for the Maine Governor's Energy Office

March 12, 2024

AUTHORS

Synapse Energy Economics:

Eric Borden

Sabine Chavin

Wooddynne Dejeanlouis

Chelsea Mattioda

Angela Zeng

Sustainable Energy Advantage:

Stephan Wollenburg

Raghu Palavadi Naga

Synapse Energy Economics, Inc.

Sustainable Energy Advantage

485 Massachusetts Avenue, Suite 3 Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

DRAFT

CONTENTS

1. Introduction and Overview of Findings

The Maine's Governor's Energy Office (GEO) contracted Synapse Energy Economics and Sustainable Energy Advantage (the "Project Team" or "Team") to assess storage procurement options that meet the criteria of Public Law 2023, Chapter 374 "An Act Relating to Energy Storage and the State's Energy Goals" (LD 1850, hereafter "the Act"), which was enacted on June 30, 2023. Section 2 of this law directs the GEO to evaluate designs for a program to procure up to 200 megawatts (MW) of commercially available utility-scale energy storage connected to Maine's transmission and distribution systems and to submit recommendations to the Public Utilities Commission ("Commission"). The Commission is directed to review the GEO's recommendations and, if it finds that the proposed program is reasonably likely to achieve the objectives established in the Act, the Commission shall take steps to implement the program.

As demonstrated in this draft report, energy storage is capable of creating societal and ratepayer value that storage resources owners may not be able to monetize. As a result, providing carefully crafted policy support can yield net benefits, including to Maine ratepayers. This report provides an overview of the Project Team's preliminary inputs, assumptions, and findings incorporating stakeholder feedback, and will be followed by a more comprehensive report and analysis at the end of March 2024.[1] As detailed in this draft report, the Project Team recommends a storage incentive structure utilizing a fixed up-front incentive paired with a performance payment based on dispatch in critical hours.

P.L. 2023 ch. 374, Section 2 states in part:

In evaluating programs for the procurement of energy storage systems, the [GEO] shall consider programs that are likely to be cost-effective for ratepayers and that are likely to achieve the following objectives:

> *A. Advance both the State's climate and clean energy goals and the state energy storage policy goals established in Title 35-A, section 3145 through the development of up to 200 megawatts of incremental energy storage capacity located in the State;*
>
> *B. Provide one or more net benefits to the electric grid and to ratepayers, including, but not limited to, improved reliability, improved resiliency and incremental delivery of renewable electricity to customers;*
>
> *C. Maximize the value of federal incentives; and*

[1] The results shown herein represent the Project Team's draft findings to date, which are subject to revision including but not limited to as a result of comments submitted by stakeholders.

> *D. Enable the highest value energy storage projects, specifically energy storage systems in preferred locations, projects that can serve as an alternative to upgrades of the existing transmission system and projects of optimal duration.*[2]

The Act directs GEO to encourage interested parties to submit relevant information to inform the evaluation. GEO issued a Request for Information (RFI) seeking input from interested parties to inform the evaluation and received eighteen responses from a range of stakeholders.[3]The Project Team leveraged qualitative and quantitative analysis of the criteria established under the law, as well as stakeholder input provided in response to the RFI issued by GEO, to assess procurement options for transmission and distribution-connected storage.

The Project Team also thoroughly assessed whether storage tends to displace fossil fuel resources which generally leads to reduced greenhouse gas emissions – or at least does not increase greenhouse gas emissions – to address the comments of several stakeholders. The Project Team's analysis confirms a substantial correlation between wholesale energy prices and greenhouse gas emissions, supporting a conclusion that storage owners are economically motivated to charge during hours of high renewable generation (when prices and emissions are lower), and discharge during periods of scarcity (when prices and emissions are higher) since this maximizes arbitrage revenue. Thus, pursuing an emissions reduction strategy is compatible with optimizing wholesale market revenues.

This analysis also incorporates stakeholder comment themes including but not limited to:

- Designing program incentives based on dispatch duration in addition to or in alternative to capacity based;
- Applying a societal cost test in addition to a utility cost test when applying the statutory criteria to weigh program options;
- To consider a range of storage durations;
- and to consider a range of potential benefits, including those that may be determined by interconnection at the transmission or distribution systems.

A thorough discussion of assumptions and incorporation of stakeholder input will be included in the final report.

The qualitative assessment of potential procurement mechanisms resulted in the selection of an upfront incentive in performance requirement, as discussed below. The Project Team created a dispatch model,

---

[2] P.L. 2023 ch. 374 section 2.

[3] GEO issued an RFI to seek public input to inform GEO's implementation of section 2 of P.L. 2023, chapter 374 on November 13, 2023, the responses to which have been reviewed by the Project Team. All comments received in response to this RFI have been made available to the public on the GEO's website at: https://www.maine.gov/energy/studies-reports-working-groups/current-studies-working-groups/storage-procurement-study-1850.

which simulates optimal charging and discharging of storage for each hour of the year over a 20-year period, to optimize storage performance under this procurement mechanism by maximizing (1) value to ratepayers and 2) market revenues. Utilizing this optimized dispatch, the Project Team then evaluated the cost-effectiveness of multiple sizes and durations of battery storage, based on an analysis of recent entrants and proposed projects currently in an advanced development stage in New England.

The Project Team assessed the cost-effectiveness of these resources through the lens of the Utility Cost Test (UCT) and a jurisdictional societal cost test (SCT). The model found that several transmission and distribution-connected storage scenarios are likely to be cost-effective for ratepayers.

Based on the analysis, the Project Team recommends transmission and distribution-connected storage resources be sought using a competitive solicitation framework that incorporates an upfront incentive and a requirement for dispatch at critical hours that will provide the greatest value to ratepayers.

2. Evaluation of Storage Procurement Mechanisms

Storage incentive programs are becoming increasingly common as more states pass legislative storage targets. Across the country, states are using differing mechanisms and incentive policies to reach their goals. The Project Team reviewed potential procurement program designs and examined how they have been implemented or proposed in other states, along with any relevant lessons learned, and the implications of each mechanism for Maine.

The Project Team considered the following program designs to procure storage based on a review of existing state programs and responses to the RFI: upfront incentives with a pay for performance element, clean peak credits, index storage credits, and tolling agreements. Typical parameters for these program designs are summarized in Table 1, and described in more detail in Appendix A.

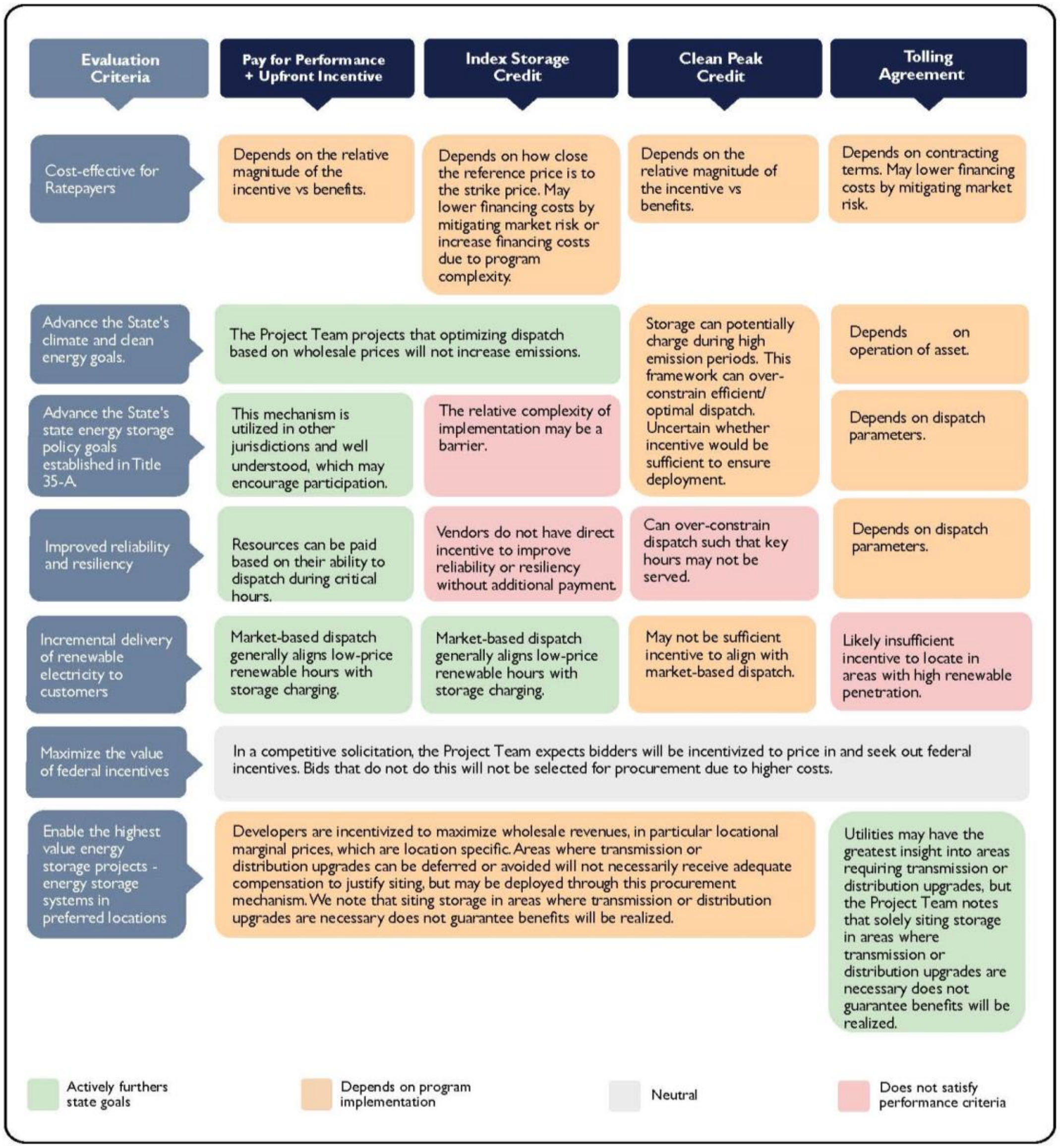
Table 1. Typical parameters for storage procurement mechanisms

	Pay for Performance + Upfront Incentive	Index Storage Credit	Clean Peak Credit	Tolling Agreement
Ownership	Third-party	Third-party	Third-party	Third-party
Dispatch control	Third-party and/or utility	Third-party	Third-party	Utility
Incentive Timing	Upfront and ongoing throughout project operations	Ongoing throughout project operations	Ongoing throughout project operations	Ongoing fixed payment
Dispatch logic	Depends on performance criteria	Maximize wholesale revenues	Scheduled based on system peaks / administratively determined	At the utility discretion depending on the purpose of procurement

Stakeholder feedback solicited through the RFI conducted by GEO raised several important issues which the Project Team considered in its evaluation of procurement mechanisms. The Project Team assessed each of the LD 1850 criteria above based on research of procurement mechanisms and stakeholder feedback from the RFI. The matrix in Figure 1 below provides a preliminary qualitative analysis of the LD 1850 criteria. The Project Team assumed all procurement mechanisms would be coupled with a competitive solicitation process.[4]

[4] This is often accomplished through a request for proposal (RFP).

Figure 1. Preliminary evaluation of LD 1850 criteria for a storage procurement mechanism



Evaluation Criteria	Pay for Performance + Upfront Incentive	Index Storage Credit	Clean Peak Credit	Tolling Agreement
Cost-effective for Ratepayers	Depends on the relative magnitude of the incentive vs benefits.	Depends on how close the reference price is to the strike price. May lower financing costs by mitigating market risk or increase financing costs due to program complexity.	Depends on the relative magnitude of the incentive vs benefits.	Depends on contracting terms. May lower financing costs by mitigating market risk.
Advance the State's climate and clean energy goals.	The Project Team projects that optimizing dispatch based on wholesale prices will not increase emissions.		Storage can potentially charge during high emission periods. This framework can over-constrain efficient/optimal dispatch. Uncertain whether incentive would be sufficient to ensure deployment.	Depends on operation of asset.
Advance the State's state energy storage policy goals established in Title 35-A	This mechanism is utilized in other jurisdictions and well understood, which may encourage participation.	The relative complexity of implementation may be a barrier.		Depends on dispatch parameters.
Improved reliability and resiliency	Resources can be paid based on their ability to dispatch during critical hours.	Vendors do not have direct incentive to improve reliability or resiliency without additional payment.	Can over-constrain dispatch such that key hours may not be served.	Depends on dispatch parameters.
Incremental delivery of renewable electricity to customers	Market-based dispatch generally aligns low-price renewable hours with storage charging.	Market-based dispatch generally aligns low-price renewable hours with storage charging.	May not be sufficient incentive to align with market-based dispatch.	Likely insufficient incentive to locate in areas with high renewable penetration.
Maximize the value of federal incentives	In a competitive solicitation, the Project Team expects bidders will be incentivized to price in and seek out federal incentives. Bids that do not do this will not be selected for procurement due to higher costs.			
Enable the highest value energy storage projects - energy storage systems in preferred locations	Developers are incentivized to maximize wholesale revenues, in particular locational marginal prices, which are location specific. Areas where transmission or distribution upgrades can be deferred or avoided will not necessarily receive adequate compensation to justify siting, but may be deployed through this procurement mechanism. We note that siting storage in areas where transmission or distribution upgrades are necessary does not guarantee benefits will be realized.			Utilities may have the greatest insight into areas requiring transmission or distribution upgrades, but the Project Team notes that solely siting storage in areas where transmission or distribution upgrades are necessary does not guarantee benefits will be realized.

Actively furthers state goals · Depends on program implementation · Neutral · Does not satisfy performance criteria

As the evaluation matrix above indicates, the Project Team found that an upfront incentive combined with a performance incentive corresponding to dispatch during the highest value hours to ratepayers is most consistent with RFI feedback and LD 1850 criteria.

The Project Team elected to model a performance requirement under which storage would be dispatched to achieve the greatest ratepayer value during critical hours for which there may be insufficient or inconsistent market price signals.[5] The specific program design would differ for transmission- and distribution-connected resources, as further described below.

3. Storage Dispatch Modeling

The procurement mechanism modeled by the Project Team was used to inform optimized dispatch of storage. For transmission-connected storage, the modeling primarily optimized storage around reducing future Pooled Transmission Facility (PTF) projects by discharging at the system peak; other hours seek to maximize revenues in the wholesale market. The modeling optimized distribution-connected storage to defer or avoid distribution peaks in the winter, while other hours were modeled to maximize revenues in the wholesale market. The optimized hourly dispatch (charging and discharging) informed both estimated market revenues and cost-effectiveness, discussed in Section 4.

3.1. Transmission-connected storage

For transmission-connected storage resources, the Project Team developed an hourly dispatch strategy that prioritized (a) responding to calls for discharging during critical hours (annual and monthly peak hours), followed by (b) maximizing energy and ancillary services revenues during all other hours. Hourly load data came from the Avoided Energy Supply Costs (AESC) 2024 study[6] to identify the hours during which discharging is most likely to be beneficial to the transmission system by reducing peaks in Maine. The time, frequency, and duration of these calls are varied over the study period, in response to shifting system peaks and anticipated changes in the ability to project the time of peak events. These calls are intended to reduce future PTF investment by reducing net load during annual and monthly system peaks.[7]

Assumed energy and reserve prices are based on future price trends from AESC 2024, and hourly profiles from ISO-NE's simulation data for 2021 from the Day-ahead Ancillary Services Initiative (DASI) impact analysis. Using a model that considers the day-ahead market price projections for energy and reserve prices, the Project Team produced estimates for wholesale market revenues that would accrue to 2-hour, 4-hour and 6-hour battery storage resources from 2027 through 2046, including energy arbitrage (revenue achieved by charging during low-price hours and discharging during higher-price hours) and reserves (in which resources sell their availability to provide energy on short notice). The

[5] Alternatively, a performance payment for dispatch at critical hours could be considered, subject to overall cost-effectiveness constraints.

[6] Synapse, *AESC 2024 Materials*, https://www.synapse-energy.com/aesc-2024-materials.

[7] The Project Team's interpretation of Section II.21 of the ISO New England Open Access Transmission Tariff suggests that the operation of these resources would not reduce Regional Network Service charges. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf.

Project Team supplemented the arbitrage and reserve revenue results from the model with additional revenue adjustments that account for potential real-time balancing revenues and revenues that could be earned during reserve scarcity hours.

In addition, the Project Team estimated the capacity revenues (from auctions and during Pay for Performance events) using capacity price projections from AESC 2024, with the seasonal components of the Qualified MRI Capacity values based on a review of the data from recent ISO studies and illustrative analysis by other entities.

3.2. Distribution-connected storage

The Project Team did not have access to utility-specific load profiles in Maine, nor did they have data on which specific distribution circuits may need upgrades due to capacity constraints in the near future. Given these limitations, the model utilized data from the National Renewable Energy Laboratory (NREL) "ResStock" dataset[8] and Synapse's proprietary heat pump load model, based on a weather year that aligned with assumptions in AESC 2024.

The Project Team simulated distribution feeders serving residential load with varying levels of space heating electrification. The analysis focused on residential load profiles because this class drives non-coincident peak load in Maine, and thus is likely to be responsible for peak load constraints on a majority of distribution feeders. For distribution-connected storage resources, an hourly dispatch strategy was developed that (a) prioritized responding to calls for discharging during critical peak hours, followed by (b) co-optimizing energy and ancillary services revenues during the non-critical hours.

Based on these load profiles, the illustrative distribution feeder is expected to peak in winter months. The model therefore assumes batteries must be held in reserve from December through February to be available to respond to dispatch calls to address the distribution system peak. For the remaining months, the Project Team simulated wholesale market revenues from energy arbitrage and ancillary services, as described in the transmission-connected resource methodology section. It is assumed that these distribution-connected resources do not take on a capacity supply obligation in order to ensure the operator can meet the requirements of the distribution system and because taking on a capacity supply obligation may preclude them from impacting Regional Network Service (RNS) charges (which are used to recover PTF costs from New England electric customers).

Because of the heterogeneity of load shapes on different parts of the distribution system, opportunities for storage to effectively defer investments will vary significantly. Furthermore, the Project Team did not have access to feeder-specific data that would enable directly modeling the use of storage to address particular distribution system peaks. Given this, the model assumes that 2-hour resources will yield a kilowatt (kW) deferral equal to 25 percent of nameplate capacity, 50 percent for 4-hour resources, and 75 percent for 6-hour resources. These assumptions are based primarily upon a review of the

[8] NREL, https://resstock.nrel.gov/datasets.

simulated feeder data, which included several significant peaks occurring during winter months, generally lasting approximately eight hours. As noted above, given the heterogeneity of loads on the distribution system, it is reasonable to expect there will be areas in which storage will be able to have a larger impact on the distribution system than assumed and others where the impact would be lower. These values are understood to be reasonable assumptions that help establish the potential distribution system value and provide a benchmark for the level of benefit that may be needed in order for a project to be cost-effective.

The Project Team acknowledges that realizing distribution system benefits from storage would likely require changes to current electric system practices (i.e. considering storage as a potential asset to the distribution system) and capabilities (e.g., distributed energy resource management systems). The benefits to the distribution system modeled here would likely not be realized in the absence of some or all of these elements.

4. COST-EFFECTIVENESS FRAMEWORK AND RESULTS

The optimized dispatch for transmission and distribution-connected storage provided annual charge and discharge profiles for which the Project Team calculated benefits and costs to assess cost-effectiveness. Based on stakeholder feedback in the RFI and statutory criteria, the Project Team selected the Utility Cost Test (UCT) and Jurisdictional Societal Cost Test (SCT)[9] for this assessment.

These two tests capture (1) the expected impact of storage on the utility system and on ratepayers and (2) the expected impact of storage on Maine.

[9] The National Standard Practice Manual (NSPM) recommends establishing a jurisdiction-specific test that reflects the applicable energy policy goals of the jurisdiction, as guided by statutes, regulations, commission orders, and stakeholder input. Any such test should adhere to fundamental BCA principles and should represent the "regulatory perspective," which is meant to represent the views of relevant policy decision-makers. See NSPM, Synapse Energy Economics, https://www.synapse-energy.com/national-standard-practice-manual-benefit-cost-analysis-distributed-energy-resources. This was also used in Synapse's evaluation of distributed generation successor programs in Maine, see https://www.nationalenergyscreeningproject.org/wp-content/uploads/2023/06/Maine-DG-Successor-Program-Evaluation_Synapse-Energy.pdf.

Table 2. Procurement program parameters

Benefits included	Costs included
Jurisdictional Societal Cost Test	
Market revenues[10] Reliability Avoided transmission and distribution (T&D) costs Energy DRIPE (positive and negative) Capacity DRIPE Greenhouse gas impacts (positive and negative)	Cost of storage Utility administration costs (if applicable)
Utility Cost Test (UCT): Perspective of utility / ratepayers	
Reliability Avoided capacity Energy DRIPE (positive and negative) Capacity DRIPE Avoided transmission and distribution (T&D) costs	Program incentive Utility administration costs (if applicable)

The Project Team utilized values, inputs, and assumptions from the AESC 2024 study to estimate the expected cost-effectiveness of storage in Maine. It is important to note that the intent of the project was to robustly assess cost-effectiveness of storage in Maine, not to precisely forecast storage prices and revenues or to precisely quantify the necessary upfront incentive. These aspects of program design should be administered by the Commission, subject to other considerations described below. The modeling assumed storage that is operational for a 20-year period beginning in 2027. Other modeling inputs and assumptions are provided below, with additional detail to be provided in the forthcoming final report.

Cost-effectiveness Results

Across the modeled combinations of capacities, durations, and interconnections that the Project Team assessed, all had a benefit-cost ratio (BCR) greater than one, which means benefits were greater than costs on a present value basis. In general, the modeling indicates systems with larger capacities tend to have greater BCRs than systems with smaller capacities. This is attributable to economies of scale in project costs. Larger storage systems have lower capital expenses on a unit cost basis than smaller projects, while at the same time most of the benefits (within a defined set of benefit categories) scale proportionally with the size of the system. There is not a monotonic relationship between storage duration and BCR; four-hour resources tended to have the highest BCR. This reflects a tradeoff between

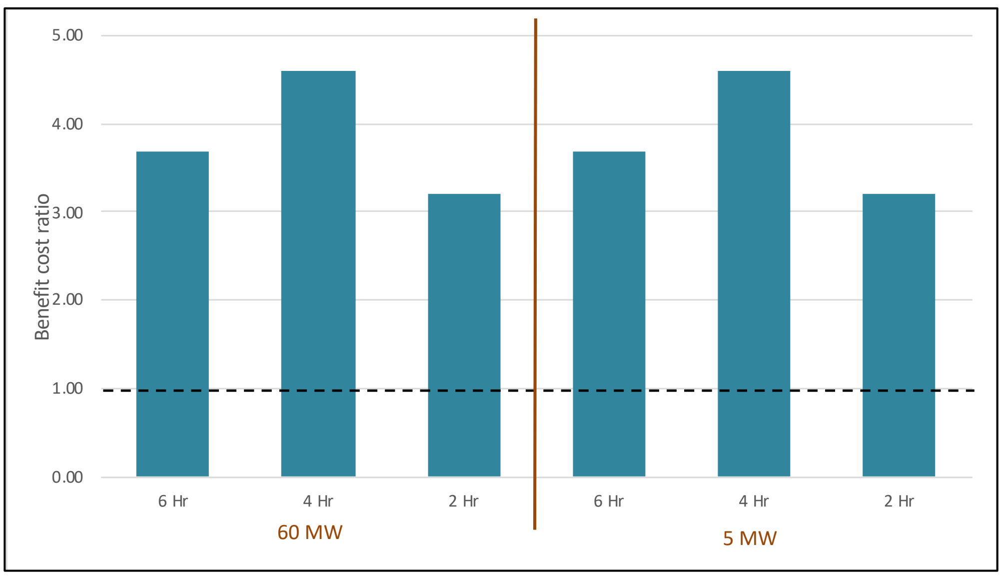
[10] Energy arbitrage, reserves, capacity revenues, and pay for performance. Our estimates include premiums to AESC prices based on real-time markets and scarcity event revenues.

higher costs for longer duration resources and how benefits for each category considered scale with different storage durations.

For transmission-connected storage, the Project Team assessed storage systems with capacities of 5 MW and 60 MW, with durations of 2, 4 and 6 hours, and assumed transmission-connected storage could participate in wholesale capacity and energy markets. For several of the transmission-connected systems the Project Team found that projected future wholesale revenues could exceed project costs on a present value basis; however, actual project developers may have higher costs of capital and shorter payback period expectations than have been accounted for in the BCA modeling.[11] In these cases, an upfront incentive was modeled based on a Connecticut battery incentive program.[12] Still, it is expected that wholesale market revenues can offset a large portion of project costs and this will be reflected in competitive bids.

The following figures display the overall BCR results for all transmission connected storage under the UCT and SCT.

Figure 2. Transmission-connected storage: Utility Cost Test results



[11] The Project Team assumes a nominal discount rate of about 4 percent, a default assumption provided in AESC 2024, and a twenty-year project life.
[12] Connecticut *Energy Storage Solutions,* https://portal.ct.gov/-/media/PURA/ESS-Commercial-and-Industrial-Fact-Sheet.pdf. The Project Team applies the $100/kWh incentive, intended for BCA purposes only.

Figure 3. Transmission-connected storage: jurisdictional Societal Cost Test results

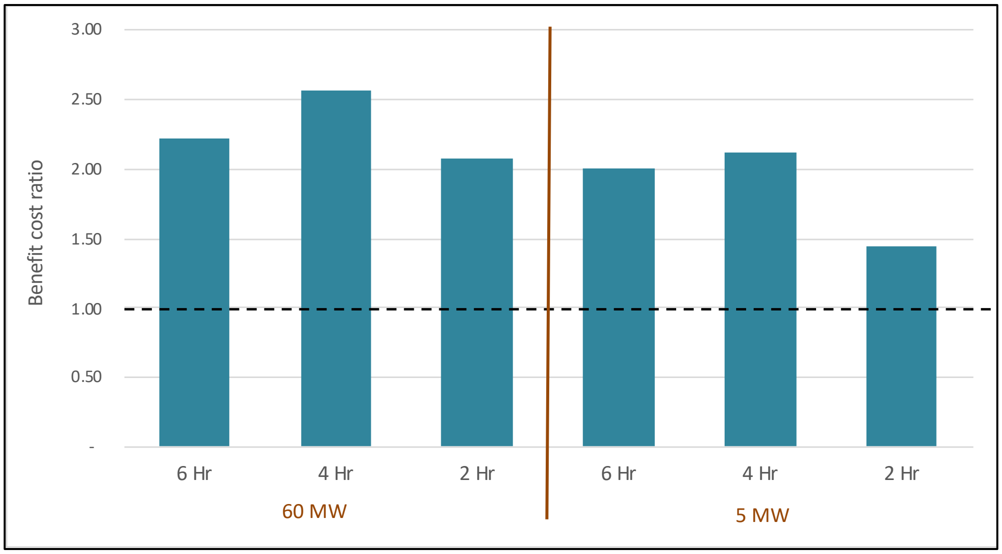
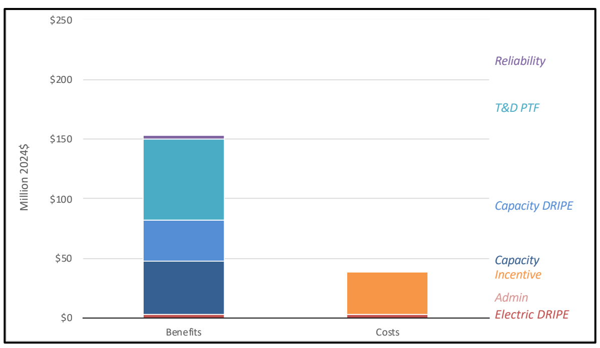
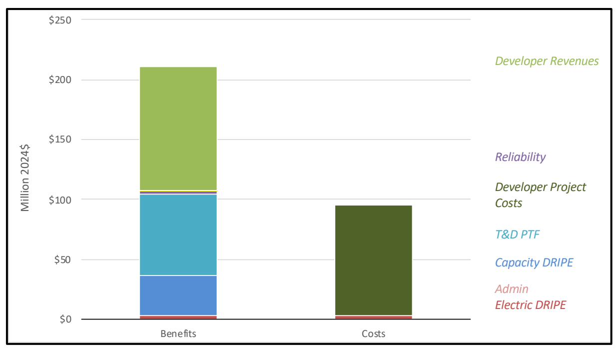


Figure 4 shows the breakdown of benefits and cost results for the 60 MW, 6 hour duration system. These charts indicate that transmission-connected storage systems can provide a wide range of benefits, largely driven by avoided marginal costs of pooled transmission facilities (PTF) in addition to avoided capacity costs.

Figure 4. Transmission-connected storage: UCT (left) and jurisdictional SCT (right) results for the 60 MW, 6 hour battery





For distribution-connected storage, systems with capacities of 1 MW and 5 MW and durations of 2, 4 or 6 hours were modeled.

Figure 5. Distribution-connected storage: Utility Cost Test results

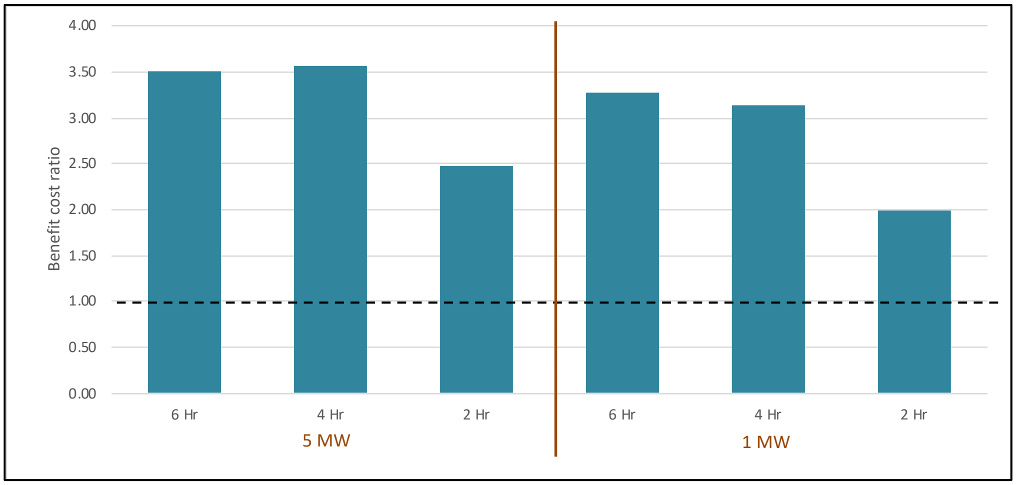
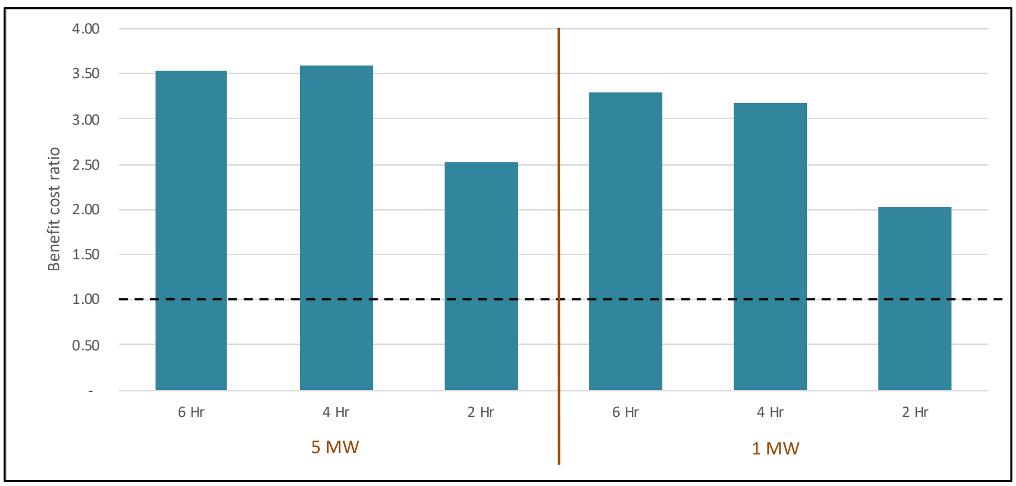


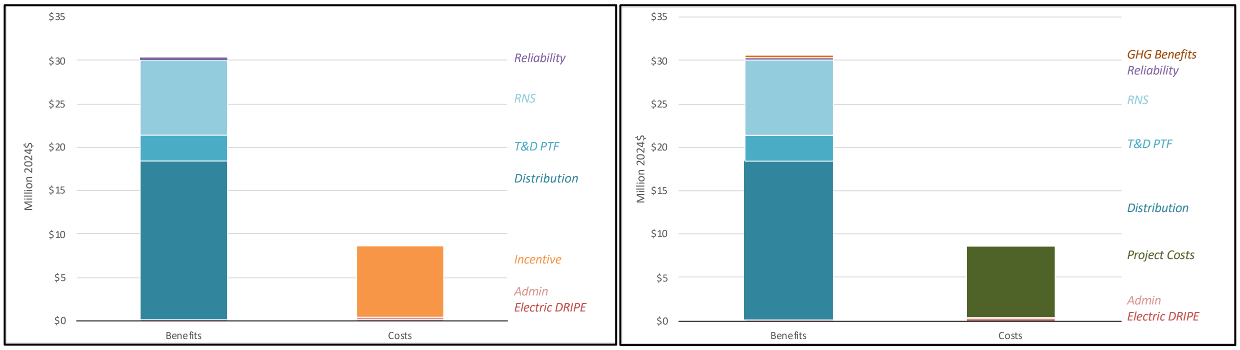
Figure 6. Distribution-connected storage: jurisdictional Societal Cost Test results



Distribution-connected storage was assumed to not participate in wholesale markets, and therefore was able to capture avoided Regional Network Service (RNS) costs when dispatched during Maine monthly peak hours. These avoided transmission costs, and avoided distribution costs based on AESC 2021 values[13], are the primary drivers of benefits.

[13] Midpoint value of $246.79/kW-year. See AESC 2021, p. 251, Table 108, https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf.

Figure 7. Distribution-connected storage: Utility Cost Test (left) and jurisdictional Societal Cost Test (right) results for a 5 MW, 6 hour battery



5. Findings and Recommendations

The Project Team found up to 200 MW of storage in Maine is likely to be cost-effective for ratepayers, from both utility ratepayer and societal perspectives. This conclusion is based on storage procurement that adheres to the following criterion:

1. A competitive solicitation overseen by a neutral third party.
2. An upfront incentive with a performance requirement that allows for storage dispatch during critical periods that best achieve ratepayer value. The specific purpose and strategy of calling events will differ for the distribution and transmission-connected resources.
3. Ongoing review and evaluation of actual program performance and impacts.

The analysis suggests that both transmission and distribution-connected resources can be cost-effective but does not identify an optimal share of the total 200 MW that should be procured. The benefits and costs for both transmission and distribution connected storage depend on specific locational parameters.

Appendix A. ASSESSED PROCUREMENT OPTIONS

Tolling Agreements

An energy storage tolling agreement procurement mechanism operates similarly to a standard tolling contract for traditional power plants.[14] Under this mechanism, a project owner is responsible for obtaining site control, permits, interconnection rights, equipment, construction contracts, and an agreeable operation date with the buyer of the system, often a utility. The utility pays for the electricity used to charge the battery storage system and receives the right to charge or discharge the system for energy, capacity, and ancillary services in the wholesale markets to maximize revenue. The project owner receives a fixed payment from the utility, often in the form of a capacity and variable O&M payment. A "partial tolling agreement" strikes a balance between utility-owned storage and a third-party owned project by allowing the project to "operate on a merchant basis" on most days in exchange for utility control on the most valuable days of the year.

Clean Peak Credit

Clean Peak Energy Credits provide incentives to clean energy technologies, including energy storage, for each megawatt-hour of energy generated during seasonal peaks.[15] Storage projects would receive a fixed level of compensation for discharging at pre-determined "peak hours."[16] Under this procurement mechanism, energy storage projects will sell their Clean Peak Credits (CPCs) to the state's energy agency or to obligated entities satisfying a clean peak portfolio requirement. In return, storage projects will receive the monetary equivalent of their credits based on a predetermined dollar amount ($/CPC * CPC).[17] Energy storage projects are required to serve an increasing portion of load during peak hours to capacity, energy, and ancillary service markets. Storage projects would also receive revenue from wholesale markets based on their services.

Upfront Incentives with Pay for Performance or Operational Requirements

Under a pay for performance mechanism, projects receive ongoing payments throughout their lifetime based on their ability to satisfy specified performance metrics. These metrics are often either based on the resource's ability to dispatch during critical hours, or based on the net system emissions impact that the resource's dispatch has on the grid. Pay for performance programs are often paired with an upfront incentive to help partially de-risk capital costs, which lowers financing costs. Transmission and distribution storage systems may have different performance criteria since they tend to provide disparate services to the grid.

---

[14] Renew Northeast, https://renewne.org/public-act-21-53-procurement-for-energy-storage/.
[15] NYSERDA, https://www.nyserda.ny.gov/All-Programs/Energy-Storage-Program.
[16] NYSERDA, https://www.nyserda.ny.gov/All-Programs/Energy-Storage-Program p.42.
[17] NYSERDA, https://www.nyserda.ny.gov/All-Programs/Energy-Storage-Program p.42.

Several states, including Connecticut, New Jersey, and California, have either proposed or implemented storage programs with pay for performance elements.

Index Storage Credit

An Index Storage Credit (ISC) mechanism seeks to establish certainty around a project's revenue stream by providing gap payments between a revenue requirement that a project developer deems necessary for economic viability and the achieved wholesale market revenue.

With an ISC mechanism, storage project developers submit "Strike Price" bids through a competitive solicitation process. These Strike Price bids should reflect the project's revenue requirement. Using one or more price indices, a "Reference Price" is calculated to indicate an approximation of available market revenue that projects could reasonably expect to earn. If the Reference Price is less than the Strike Price, meaning the available market revenue is less than the project needs to be economically viable, projects will get paid the difference. If the Reference Price is greater than the Strike Price, meaning available market revenue exceeds the project's minimum needs, the project will pay the difference to the program administrator (typically a utility or state entity)