MAINE GOVERNOR'S
Energy Office

Maine Energy Storage Program

Recommendations Submitted to the Maine Public Utilities Commission

Pursuant to Public Law 2023, Chapter 374

December 23, 2024

This report is available online at maine.gov/energy

The Maine Governor's Energy Office (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. As the lead energy office for the state, GEO is responsible for activities including providing policy leadership and technical assistance, developing energy programs, monitoring energy markets, and reporting on heating fuel and energy prices. GEO works in partnership with various state agencies, federal and local officials, industry, nonprofit interests, and academia on energy issues.

The GEO is grateful for the engagement of stakeholders who provided valuable comments in response to GEO’s Request for Information and Opportunity for Comment. GEO also acknowledges the support of its contractor, Synapse Energy Economics, and subcontractor Sustainable Energy Advantage, who developed the technical analysis described in this report.

Table of Contents

This report is available online at.......... 1
Table of Contents.......... 2
List of Figures.......... 3
List of Tables.......... 4
Executive Summary.......... 5
Introduction.......... 6
Energy Storage Policy Development.......... 7
Energy Storage Commission.......... 7
An Act To Advance Energy Storage in Maine.......... 8
Maine Energy Storage Market Assessment.......... 8
An Act to Address Battery Storage System Decommissioning and Clarify Solar Energy Development Decommissioning.......... 9
An Act Relating to Energy Storage and the State's Energy Goals.......... 10
Long-Duration Energy Storage Report.......... 10
Maine's Energy Storage Landscape Today.......... 11
Regional Outlook.......... 15
National and Global Energy Storage Trends.......... 17
Development of Energy Storage Program Recommendations.......... 19
Public Engagement.......... 21
Statutory Objectives.......... 33
Program Design Options.......... 42
Recommended Procurement Design.......... 51
Cost-effectiveness and Ratepayer Impact Analysis.......... 56
Transmission-Connected Storage Analysis.......... 63
Distribution-Connected Storage Analysis.......... 64
Cost-Effectiveness Framework.......... 66
Cost-Effectiveness Results.......... 74
Energy Storage Program Recommendations.......... 78

Program Priorities 78
Allocation of Capacity 79
Solicitation and Incentive Structure 79
Program Administration 79
Statutory Authority 79
Additional Considerations 80
References 81

List of Figures

Figure 1: Stylized example of intra-day electricity load shifting in a high-renewable energy electric system. 12
Figure 2: Summary of selected energy storage technology key characteristics. 13
Figure 3: Rendering of Cross Town Energy Storage project under construction in Gorham, Maine. 14
Figure 4: Resources in the ISO-New England interconnection queue, January 2024 15
Figure 5: Volume-weighted average lithium-ion battery pack and cell price split, 2013-2024 18
Figure 6: Lazard's Levelized Cost of Storage Comparison -- Version 9.0 ($/kW-year) 19
Figure 7: Cumulative CO_2 emissions reduction over 20-year study period (positive values indicate reductions in greenhouse gas emissions). 36
Figure 8: Illustrative tolling agreement framework 44
Figure 9: Illustrative Clean Peak Credit framework 45
Figure 10: Illustrative upfront incentive with pay for performance 47
Figure 11: Illustrative Index Storage Credit mechanism 49
Figure 12: Developing a jurisdictional-specific societal cost test 67
Figure 13: Utility Cost Test for Transmission-connected storage: Benefit-Cost ratios 75
Figure 14: Societal Cost Test for Transmission-connected Storage: Benefit-Cost ratios 75
Figure 15: Utility Cost Test for Distribution-connected storage: Benefit-Cost ratios 76
Figure 16: Societal Cost Test for Distribution-connected storage: Benefit-Cost ratios 76

List of Tables

Table 1: Operational utility-scale storage projects in Maine 13
Table 2: Energy storage deployment goals and status by state, August 2024........... 16
Table 3: Summary of key program parameters for program designs evaluated 42
Table 4: Summary of program design options compared to objectives of the Act... 52
Table 5: Count of Modeled Events per Month 57
Table 6: Event Duration (Hours) 58
Table 7: Seasonal marginal reliability impact of storage resources assumptions 62
Table 8: Benefits and costs in Utility Cost Test and Jurisdictional Societal Cost Test 68
Table 9: Benefit-Cost Analysis Inputs and Assumptions 70
Table 10: Modeled Incentive Values 73

Executive Summary

The Maine Governor's Energy Office (GEO) prepared this report pursuant to Public Law 2023, Chapter 374 §2, which directed the GEO to evaluate and recommend designs for a cost-effective program to procure up to 200 megawatts of utility-scale energy storage systems. These recommendations support the achievement of Maine's statutory energy storage deployment goals, reduce energy costs for Maine people and businesses, increase the resilience of Maine's electricity grid, and support Maine's clean energy and climate goals.

This program will contribute to the achievement of Maine's statutory goal of 400 megawatts of energy storage deployed by 2030.

The GEO conducted extensive public engagement, including a Request for Information (RFI) and an Opportunity for Comment on draft recommendations. Eighteen responses to the RFI and thirteen responses to the Opportunity for Comment provided input and insights from a range of stakeholders.

The GEO evaluated multiple program design options, including pay-for-performance mechanisms, clean peak credits, tolling agreements, and an index storage credit mechanism. A robust cost-effectiveness analysis demonstrates that competitively procured utility-scale energy storage projects will deliver substantial benefits to electric ratepayers, primarily by reducing the need for more costly electricity grid investments. Furthermore, the analysis finds the typical electric ratepayer could expect to save $1.50-$1.77 per month on average over the first ten years of the program.

The GEO recommends the Maine Public Utilities Commission (PUC) implement competitive procurement programs for 200 megawatts of energy storage consistent with the program designs described in this report.

MAINE GOVERNOR'S Energy Office

Introduction

Increasing the resilience of the electric grid and ensuring affordability are critical priorities for Maine as the state advances the transition to a more reliable and cleaner energy future. Strengthening the grid's capacity to accommodate peak demand, incorporate renewable energy, and reduce reliance on costly imported fossil fuels is essential to ensuring stable and affordable electricity for Maine residents and businesses.

Energy storage technologies can play a pivotal role in modernizing the grid, enabling better management of distributed energy resources (DERs), minimizing disruptions, and stabilizing energy costs. By deploying cost-effective energy storage solutions, Maine can enhance grid reliability and mitigate price volatility associated with fossil fuel dependence.

Maine has committed, through bipartisan legislation, to reducing greenhouse gas emissions by 45% from 1990 levels by 2030 and 80% by 2050, and achieving carbon neutrality by 2045. Governor Mills has also established a goal of 100% clean electricity by 2040, building on the existing statutory requirement for 80% renewable electricity by 2030. These measures will reduce Maine's reliance on imported fossil fuels, which have exposed the state to significant price volatility attributable to global events including the Russian invasion of Ukraine and COVID-19-related supply chain disruptions.

Maine's statewide climate action plan, *Maine Won't Wait*, first published in 2020 and reaffirmed in 2024, as well as the latest Maine Energy Plan identify energy storage as a key technology for achieving the state's emissions reduction targets and optimizing renewable energy use. By increasing energy storage capacity, Maine can maximize the value of renewable resources, reduce carbon emissions, and accelerate the transition to a resilient, affordable, and clean energy system.

Governor Mills signed "An Act Relating to Energy Storage and the State's Energy Goals" (Public Law 2023, Chapter 374, hereafter "the Act") in June 2023. This legislation directed GEO to "evaluate designs for a program to procure commercially available utility-scale energy storage systems connected to the transmission and distribution systems," and to "provide its recommendations to the Public Utilities Commission for a program to procure up to 200 megawatts of energy storage capacity." This report fulfills that legislative directive, advancing the first utility-scale energy storage procurement program in Maine.

Energy Storage Policy Development

Maine has taken multiple steps to examine and pursue the significant benefits energy storage technologies can provide. Key recent activities which have informed this report are summarized here.

Energy Storage Commission

Resolves 2019, Chapter 83 established the Commission to Study the Economic, Environmental, and Energy Benefits of Energy Storage to the Maine Electricity Commission (hereafter the "Energy Storage Commission"). The Energy Storage Commission, comprising fourteen members appointed by the President of the Maine Senate and Speaker of the Maine House of Representatives, issued its final report in December 2019.[i] The Report contained four unanimous findings of the Energy Storage Commission:

1. Energy storage has the potential to reduce costs and improve reliability;
2. Energy storage complements and supports renewable energy;
3. Energy storage technology is dynamic and evolving and presents cost-effective options; and
4. Energy storage development may be inhibited by market barriers or a lack of clear regulatory signals.

The Energy Storage Commission also developed the following recommendations:

1. Establish state targets for energy storage development;
2. Encourage energy storage paired with renewable and distributed generation resources;
3. Advance energy storage as an energy efficiency resource;
4. Address electricity rate design issues relating to time variation in costs;
5. Clarify utility ownership of energy storage;
6. Advocate for energy storage consideration in regional wholesale markets; and
7. Conduct an in-depth Maine-specific analysis of energy storage costs, benefits and opportunities.

While a full progress report on each of these recommendations is beyond the scope of this report, each has resulted in continued policy and other action since 2019. Recommendations 1 through 5 and 7 have been the subject of subsequent legislation described below, and advocacy consistent with recommendation 6 has occurred regularly since 2019.

An Act To Advance Energy Storage in Maine

Governor Mills signed Public Law 2021, Chapter 298, "An Act To Advance Energy Storage in Maine," in June 2021. This legislation established Maine as the ninth state in the country with statutory energy storage deployment goals:

- 300 megawatts of installed capacity located in the State by December 31, 2025, and
- 400 megawatts of installed capacity located in the State by December 31, 2030.

The legislation also authorized the inclusion of energy storage systems in the energy efficiency measures supported by the Efficiency Maine Trust (hereafter "Efficiency Maine") and expanded the objectives of Efficiency Maine's programs to include reducing or shifting demand for electricity or balancing load in order to maximize the potential value of customer-sited energy storage systems. The legislation also directed Efficiency Maine to conduct a pilot program not exceeding 15 megawatts that would provide energy storage systems to critical care facilities, including but not limited to hospitals, health care facilities, fire departments, emergency medical service departments, police departments, public safety buildings, emergency shelters, and other facilities providing critical services. Efficiency Maine has incorporated energy storage technologies into its programs,[ii] and reported on the status of the critical care facilities pilot program in its annual reports.[iii]

The legislation also directed the Commission to investigate and, where appropriate, implement electric utility rate designs that account for time variation in cost components. The Commission initiated multiple proceedings in response to this directive.[iv] The Commission was also directed to consider the feasibility of a power-to-fuel pilot program, which resulted in a report to the Legislature.[v]

Finally, the legislation directed the GEO to conduct an energy storage market assessment study.

Maine Energy Storage Market Assessment

GEO released the Maine Energy Storage Market Assessment (hereafter the "Market Assessment"), conducted by Energy and Environmental Economics (E3), in March 2022.[vi] The Market Assessment evaluated storage technologies and use cases, assessed the market and policy landscape and potential hurdles to storage deployment, and developed and applied cost-benefit analyses to examine the likely value of energy storage deployment in a range of use cases.

The Market Assessment included the following key takeaways:

- Several promising energy storage technologies may help Maine achieve its target, though batteries will likely comprise most of the storage deployed in Maine in the next five years.
- Energy storage may provide many distinct benefits to Mainers, with potential value streams evolving as the needs of the electric grid and customers change.
- Cost-benefit analysis results show cost-effectiveness for wholesale ("grid-connected") storage but continued cost declines and the ability to monetize multiple value streams will be important.
- Customer-sited storage can reduce customer bills and increase resiliency by protecting against outages (loss-of-load).
- Long-duration energy storage technologies may support New England's need for clean, firm energy in a deeply decarbonized future.
- Notable hurdles remain related to near-term storage deployment in the state.

In summarizing cost-benefit analyses of six different energy storage deployment use cases, the Market Assessment found that "overall, the cost-benefit analysis shows net benefits for owners of wholesale storage, both standalone and systems paired with solar, by 2025. From the perspective of society, storage benefits outweigh costs already in 2023, largely due to avoided T&D costs. However, those benefits are expected to be project-specific and location-dependent."[vii]

An Act to Address Battery Storage System Decommissioning and Clarify Solar Energy Development Decommissioning

Governor Mills signed "An Act to Address Battery Storage System Decommissioning and Clarify Solar Energy Development Decommissioning" in June 2023. This law establishes decommissioning requirements for battery energy storage systems two megawatts or greater, including submission of a decommissioning plan to the applicable state environmental permitting entity (the Maine Department of Environmental Protection or Maine Land Use Planning Commission) for approval. The decommissioning plan must provide for the recycling and proper disposal of components, and restoration of the site including restoration of farmland if applicable. Decommissioning plans must also be accompanied by a performance bond or other financial surety for the total cost of decommissioning, including recycling and disposal. Plans must be updated periodically and transferred with any transfer of ownership.[viii]

An Act Relating to Energy Storage and the State's Energy Goals

Governor Mills signed "An Act Relating to Energy Storage and the State's Energy Goals" (Public Law 2023, Chapter 374, hereafter "the Act") in June 2023. This legislation directed GEO to develop recommendations for the state's first targeted energy storage procurement program to support achievement of the statutory energy storage deployment goals. This report fulfills that legislative directive.

In addition, this legislation authorized the GEO to re-evaluate and increase the statutory energy storage deployment goals, and directed the Commission to solicit stakeholder input and submit a report to the Legislature regarding whether and, if so, at what cost and under what conditions an investor-owned transmission and distribution utility may own, have a financial interest in or otherwise control an energy storage system in order to perform its obligations as a transmission and distribution utility in an effective, prudent, and efficient manner. The Commission released the resulting report in March 2024.[ix]

Finally, this legislation directed the GEO to study long-duration energy storage, including opportunities for new and emerging long-duration energy storage technology that would support the State's need for clean, firm power generation.

Long-Duration Energy Storage Report

GEO released the Long-Duration Energy Storage Report in February 2024.[x] The Long-Duration Energy Storage Report reviewed technology options, key considerations, costs, and scenarios for the use of long-duration energy storage in Maine.

The Long-Duration Energy Storage Report included the following policy considerations and conclusions:

- Continue to support technology neutral approaches to storage policy goals, while recognizing duration priorities may evolve with technology and energy system changes.
- Track storage deployments in New England and Maine, including key characteristics such as technology and duration.
- Monitor federal and private-sector investments in research, development, and demonstration of long-duration energy storage technologies.

- Seek opportunities to engage in federally funded pilot projects for long-duration energy storage technologies.
- Consider joint procurements of energy storage resources, including long-duration energy storage resources, in future resource procurements to capitalize on diversity benefit.
- Participate in advancing regional market design improvements to ensure fair compensation for storage resources that contribute to cost-effectively meeting electricity needs.

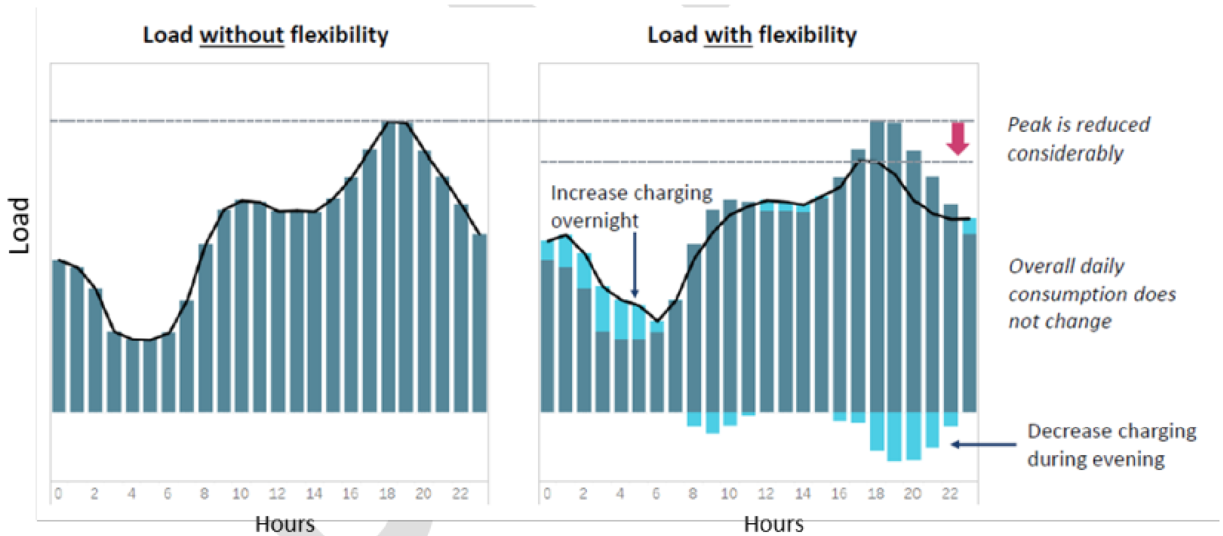
Maine's Energy Storage Landscape Today

Energy storage technologies absorb electric energy and store it for a period of time, then discharge the stored electricity at a later time. Electric energy storage is novel in that the primary mechanism for serving electricity demand, or load, has historically been the variable dispatch of generation resources such that electricity is generated effectively simultaneously with when it is used. Because electric demand varies from moment-to-moment, as individuals turn appliances on and off; hour-to-hour as people wake up to hot showers and coffee brewing, or arrive home in the evening to switch on lights and appliances for the evening; and day-to-day, as heating loads increase during a cold week and decrease during a late winter thaw, without energy storage electric generation must be available to meet demand in each period.

In competitive electricity markets such as New England, wholesale electricity prices reflect these supply and demand characteristics. During periods of ample available generation and low demand from consumers, wholesale prices trend lower, while periods of high demand put upward pressure on prices, inducing by utilizing more expensive generation sources to operate. These dynamics are amplified by the deployment of renewable energy generation such as solar and wind, which, once operational, can produce electricity without the dynamic of fuel price variability when the sun shines or the wind blows.

Energy storage technologies can leverage the differential in value by charging during low-cost, abundant electricity periods and discharging during higher-cost constrained periods.

Figure 1: Stylized example of intra-day electricity load shifting in a high-renewable energy electric system.[xi]



A wide range of energy storage technologies exist, with many more in various stages of research, development, and commercialization. Electric energy storage technologies are generally categorized as electro-chemical (batteries, with a wide range of electro-chemical compositions), electrical (capacitors, super-capacitors), thermal (hot water, solar thermal), mechanical (pumped storage, compressed air, flywheel), or chemical/fuel-based (hydrogen, synthetic fuels). Each technology differs in commercial maturity, performance characteristics, availability, and other important factors. The Market Assessment concluded "Lithium-ion batteries are viewed as the most likely near-term deployable storage technology in Maine today, given its current competitive costs, expectations for continued declining costs, and the potential high-value services it provides to the grid."[xii]

Figure 2: Summary of selected energy storage technology key characteristics.[xiii]

	Pumped hydro	Li-ion Battery	CAES/A-CAES	Iron-Air Battery	Flow Battery	Solar Thermal Storage
Commercial readiness	High	High	Medium	Medium	Medium	High
Siting flexibility	Low	High	Low	High	High	Low
Scalability (size, location requirements, manufacturing capability)	Low	High	Low	Medium-High	Medium-High	High
Duration	Long (6-10 hrs)	Flexible (1-6 hrs)	Long (8-48 hrs)	Long (100+ hrs)	Flexible (6+ hrs)	Long (6-10 hrs)
Roundtrip efficiency[29]	65-85%	85-95%	40-80%	>45%	70-85%	40%
Response time (to provide full power)	Minutes	Seconds	Minutes	Seconds	Seconds	Varies

Maine has a modest number of energy storage projects already operating, largely developed either in response to specific state programs or in particularly advantageous locations where wholesale market conditions and pre-existing infrastructure enable deployment. These existing resources are summarized in Table 1. This table does not include customer-sited or behind-the-meter energy storage projects.

Table 1: Operational utility-scale storage projects in Maine[xiv]

Resource Name	Town	Nameplate Capacity (MW)
Madison BESS	Madison	4.7
William F. Wyman	Yarmouth	16.7
Rumford BESS	Rumford	4.7
Great Lakes Millinocket	Millinocket	20.9
Bonny Eagle Renewable BESS	Hollis Center	8.0
Rumford Renewable BESS	Rumford	8.0
Total		**63**

Additional notable energy storage projects in development include the Cross Town Energy Storage project, developed by Plus Power and located in Gorham, Maine. Cross Town broke ground in February 2024, and when completed it will be among the largest energy storage projects in the region. A rendering is provided in Figure 3. The project is a 175-megawatt, 350-megawatt-hour energy storage project which will participate as a capacity resource through ISO-New England as well as providing energy arbitrage and ancillary services through existing markets.

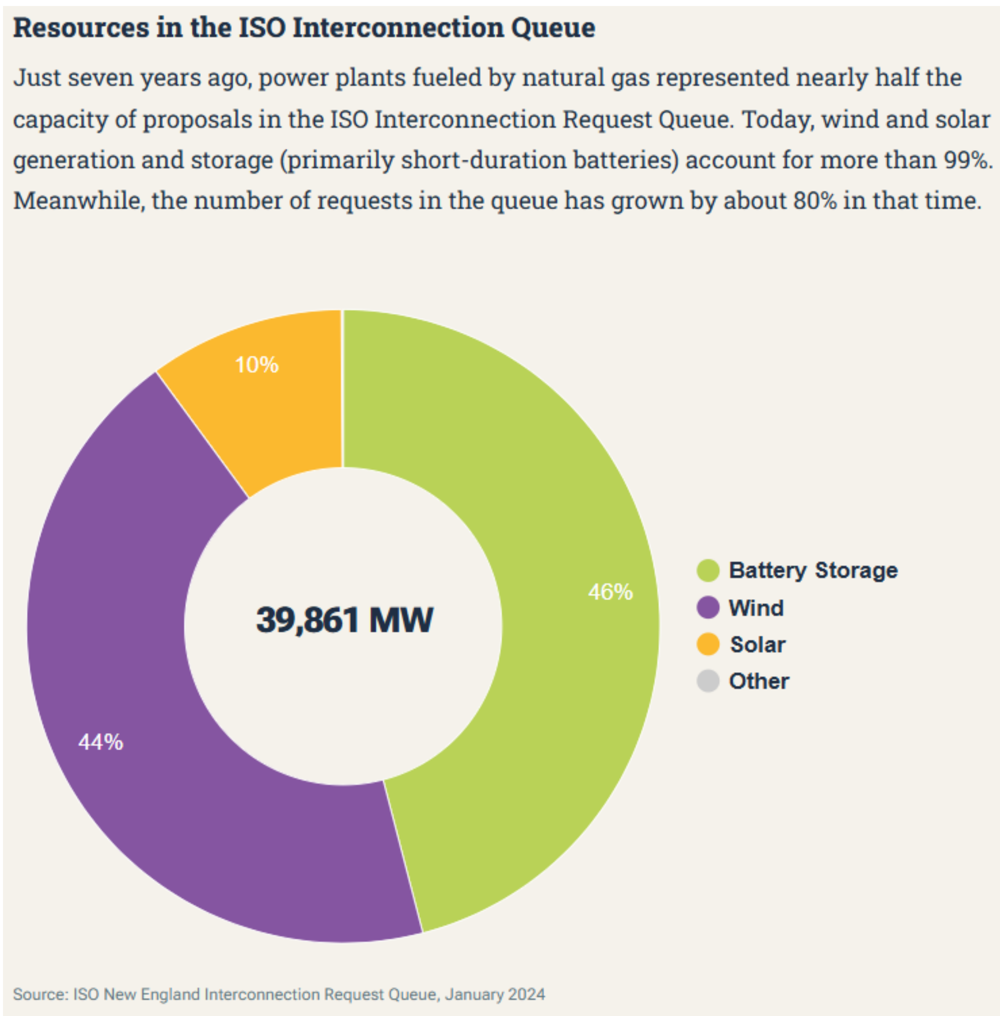
Figure 3: Rendering of Cross Town Energy Storage project under construction in Gorham, Maine[xv]

In August 2024, the U.S. Department of Energy awarded $147 million in funding for the largest long-duration energy storage project in the world to be located in Lincoln, Maine. The funding is awarded to the six New England states as part of a broader package of projects, and will be administered in partnership with Form Energy, a New England-based technology company that manufactures and operates iron-air batteries. Iron-air technology enables multi-day long-duration energy storage. The project, at the site of the former mill in Lincoln, will enhance grid resilience and optimize the delivery of renewable energy.[xvi]

Regional Outlook

With declining costs and increasingly clear value to be captured from energy storage capabilities, the regional electricity system is poised for significant new energy storage deployment. ISO-New England reports 46% – more than 18 gigawatts – of the proposed new resources seeking interconnection to the regional grid are battery storage resources, underscoring the extent to which this technology is increasingly ready for deployment in Maine and across New England.

Figure 4: Resources in the ISO-New England interconnection queue, January 2024[xvii]



In addition to Maine, three other New England states have also established energy storage deployment goals and enabling procurements or other policy mechanisms to support their achievement. A total of twelve states across the country have established storage deployment goals, with a variety of carve-outs, metrics, and other features. These goals and mandates are summarized in Table 2.

Table 2: Energy storage deployment goals and status by state, August 2024.[xviii]

State	Energy storage goal	Energy storage deployed (MW)
California	1,825 MW by 2024	10,383
Connecticut	1,000 MW by 2030	2
Maine	400 MW by 2030	63
Maryland	3,000 MW by 2033	20
Massachusetts	5,000 MW by 2030	257
Michigan	2,500 MW by 2030	16
Nevada	1,000 MW by 2030	940
New Jersey	2,000 MW by 2030	90
New York	6,000 MW by 2030	359
Oregon	1% of 2014 peak load	35
Rhode Island	600 MW by 2033	
Virginia	3,100 MW by 2035	1

The Commonwealth of Massachusetts administers several energy storage programs, including the Clean Peak Standard, which is designed to provide incentives for front-of-the meter clean energy technologies that supply electricity or reduce demand during seasonal peak periods, including energy storage. Electricity suppliers are required to purchase a certain percentage of Clean Peak Energy Certificates each year.[xix] In 2024, the Massachusetts Department of Energy Resources conducted a Clean Peak Standard Programmatic Review, examining a range of topics related to the program including primary focus areas Clean Peak Energy Certificate Multipliers, the Minimum Standard, and Alternative Compliance Rate. The Department has also filed three emergency rulemakings in July and October 2024.[xx]

In March 2024, the New York State Energy Research and Development Authority (NYSERDA) published New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage.[xxi] This Roadmap assesses necessary market reforms and cost-effective procurement mechanisms to achieve New York's energy storage goals. Among the program design options considered is a novel proposal for an Index Storage Credit mechanism, which is characterized as:

> "similar in many ways to the well-established Index REC structure adopted by the [New York Public Service] Commission and used across most of NYSERDA's Clean Energy Standard procurements. In those programs, a Renewable Energy Certificate (REC) representing the environmental attributes of renewable energy is created for each megawatt hour (MWh) of renewable electricity actually generated and supplied. The RECs are purchased by NYSERDA when they are created, ensuring that generators are compensated only for the renewable energy they generate and deliver to the grid."[xxii]

The Roadmap focuses on 4-to-8-hour duration storage, while emphasizing the importance of further research and innovation into long duration storage.

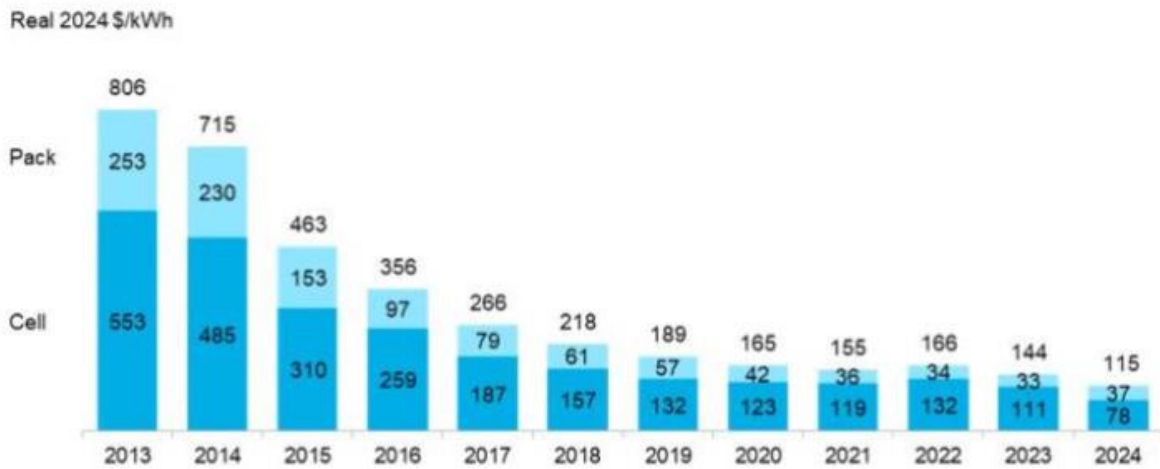
Other states around the country have also implemented energy storage procurements, each with a different approach based on individual state energy goals and needs and with numerous approaches to most cost-effectively and efficiently deploy energy storage. Several such programs are also described in comments submitted to the GEO during the development of this report, summarized below.

National and Global Energy Storage Trends

Much of the existing energy storage capacity in the United States comes from hydroelectric pumped storage, with just under 23 gigawatts – primarily built before 2000 – operating across the country. In recent years, lithium-ion batteries have made up more than 90 percent of new energy storage installations: between 2010 and the end of 2022, nearly 9 gigawatts of battery storage resources have come online. The U.S. is expected to add 63 gigawatts of installed energy storage capacity between 2023 and 2027.[xxiii] The U.S. Department of Energy forecasts continued significant growth of energy storage resources over the next several decades, including 225 to 460 gigawatts of long-duration energy storage resources by 2050 to support net-zero policies and high renewable penetration across the country.[xxiv]

These forecasts are underpinned by the precipitous decline in energy storage technology costs exemplified by lithium-ion battery packs. Globally, lithium-ion battery prices dropped 20% between 2023 and 2024, the largest annual drop since 2017.[xxv] As illustrated in Figure 5, since 2013, lithium-ion battery pack prices have fallen 84%, attributable to expanded cell manufacturing capacity, economies of scale, low metal and component prices, and other factors, according to BloombergNEF.[xxvi]

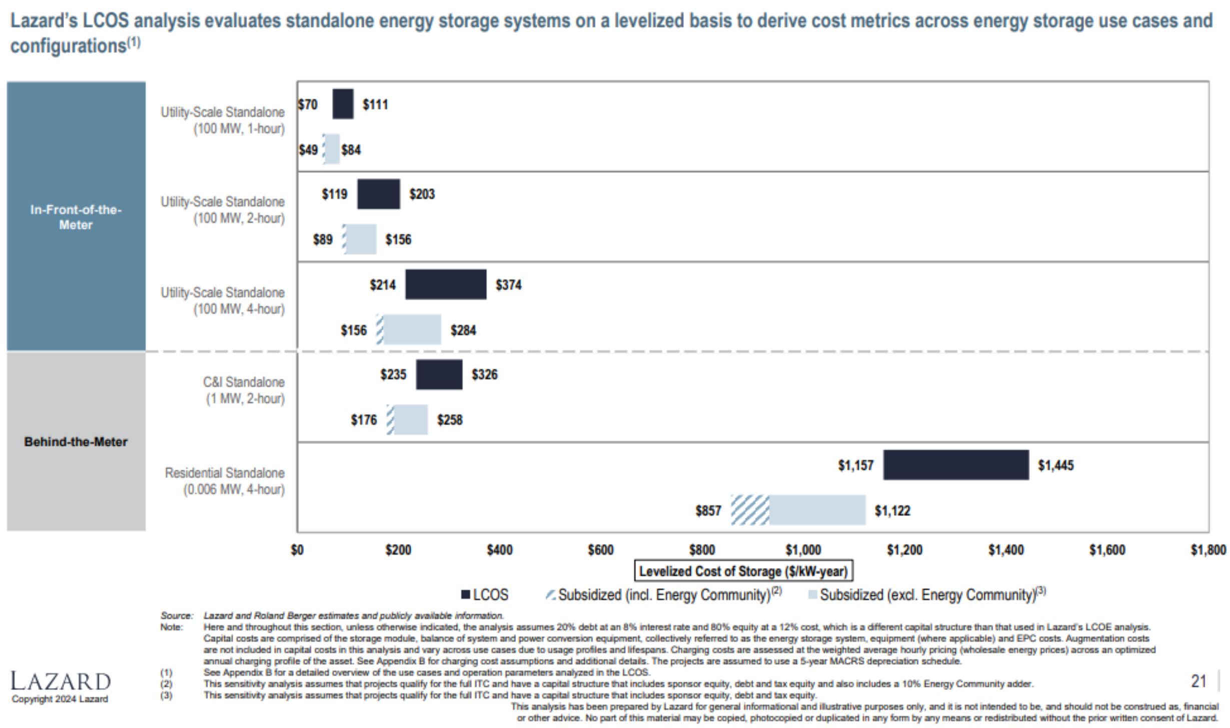
Figure 5: Volume-weighted average lithium-ion battery pack and cell price split, 2013-2024[xxvii]



Source: BloombergNEF. Note: Historical prices have been updated to reflect real 2024 dollars. Weighted average survey value includes 343 data points from passenger cars, buses, commercial vehicles and stationary storage.

Levelized cost of energy is a common metric used to benchmark the typical cost of deploying generation technologies. Lazard, a longstanding source for levelized cost of energy metrics, also publishes a levelized cost of storage benchmark to compare energy storage technologies on a capacity basis with generation technologies. Lazard's most recent benchmarks, published in June 2024 and summarized in Figure 6, suggest that utility-scale lithium-ion battery energy storage projects are likely to be cost-competitive or comparable with many well-known sources of generation, and are increasingly competitive with the support of federal tax incentives.

Figure 6: Lazard's Levelized Cost of Storage Comparison -- Version 9.0 ($/kW-year)[xxviii]



Development of Energy Storage Program Recommendations

Section 2 of the Act directs the GEO:

> "shall, in consultation with the Public Utilities Commission, evaluate designs for a program to procure commercially available utility-scale energy storage systems connected to the transmission and distribution systems, including, but not limited to, through the use of an index storage credit mechanism.[1]
>
> 1. In evaluating programs for the procurement of energy storage systems, the office shall consider programs that are likely to be cost-effective for ratepayers and that are likely to achieve the following objectives:

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[1] The Act defines an index storage credit mechanism as "a mechanism for setting contract prices for energy storage capacity using the difference between a competitively bid price, or strike price, and daily reference prices calculated using an index designed to approximate wholesale market revenues available for each megawatt-hour of capacity and including a mechanism to provide for a net payment from the operator of the storage capacity project to ratepayers in the event the reference price exceeds the strike price." P.L. 2023 ch. 374 §2 (1).

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
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."

Based on this analysis, GEO is charged with putting forward recommendations for a program enabling deployment of up to 200 megawatts of energy storage that advances the state's climate, clean energy, and energy storage goals; identifies what is most cost effective for ratepayers; includes design elements to improve reliability, resiliency, and facilitates increased renewable energy deployments; enables highest value energy storage, including in preferred locations, reduces necessity of upgrades, and operates projects of optimal duration. Consideration of each of these statutory criteria is described later in this report.

Following this submittal, the Act requires the Commission to review the recommendations and determine whether the program recommendations are reasonably likely to achieve the objectives set forth in the Act. Upon finding the proposed program reasonably likely to achieve the objectives, the Commission shall take steps to implement the program in accordance with any applicable authority the Commission may have under law, and may submit to the joint standing committee of the Legislature having jurisdiction over energy matters recommendations for any changes to law needed to allow the Commission to fully implement the program.

GEO has taken care in developing recommendations for a program that will be cost-effective for ratepayers and that advance the State's climate and clean energy goals; provide net benefits to the electric grid and to ratepayers; maximize federal incentives; and enable the highest value energy storage projects.

The Act requires the submission of the GEO's recommendations by March 31, 2024. The GEO acknowledges a delay in finalization of the energy storage petition. GEO wrote to the Commission on March 29, 2024, informing the Commission of GEO's completion of the evaluation of energy storage program design options. This letter provided notice of intention to submit recommendations to the Commission consistent with the Act.

Unprecedented federal funds became available that required prioritization of GEO resources to ensure Maine's participation in an opportunity for historic levels of funding provided to the energy transition through the Inflation Reduction Act and Bipartisan Infrastructure Law programs. The reallocation of office resources to seek federal funding advanced deployment of energy storage, including through the successful federal award enabling the largest long-duration energy storage project in the world to be constructed in Lincoln, Maine, as described above.

Public Engagement

The Act requires that the GEO "encourage interested parties to submit relevant information to inform the evaluation."[xxix] The GEO conducted two public comment periods – a Request for Information, and a subsequent Opportunity for Comment regarding GEO's draft analysis – in fulfillment of this requirement. The range and substance of responses to both comment opportunities indicate robust commercial interest in a competitive procurement. The GEO is grateful for the engagement and valuable information provided by all respondents.

Request for Information

GEO issued its Request for Information Regarding Development of the Maine Energy Storage Procurement in November 2023 (hereafter "the RFI").[xxx] The RFI sought input on how best to design a program to achieve the statutory goals, sources of data to support the implementation of a cost-effective program, recommendations to increase the reliability and resiliency of the grid, how the GEO should consider preferred location and optimal duration, input regarding various pricing mechanisms including index storage credits, and barriers to achieving the state's energy storage procurement goals. Eighteen entities responded to the RFI with valuable information that informed the development of the GEO's recommendations. All responses are summarized below, and available in their entirety on the GEO's website.[xxxi]

Alliance for Climate Transition[2]

The Alliance for Climate Transition (ACT) advocated for aligning Maine's energy storage program with its decarbonization and economic development goals. ACT emphasized the importance of creating a clear and transparent process for developers to participate in the program.

ACT also highlighted the potential of storage to attract investment and create local jobs, and recommended measures to ensure that the program supports innovative business models and technology advancements, fostering economic growth alongside clean energy benefits.

ACT also highlighted interconnection barriers, which they identified as a major obstacle to storage deployment. ACT proposed streamlining interconnection processes and providing technical assistance to developers to accelerate project timelines.

Central Maine Power

Central Maine Power (CMP) suggested leveraging energy storage to improve grid reliability and reduce operational costs. CMP highlighted the potential of storage to defer investments in transmission and distribution infrastructure, reducing costs for ratepayers. CMP recommended prioritizing projects that enhance reliability in high-demand areas, such as Portland and other urban centers.

Additionally, CMP emphasized the importance of aligning storage deployment with Maine's clean energy goals, noting that storage could play a key role in stabilizing the grid as renewable generation increases, ensuring a reliable and cost-effective energy transition.

Clean Energy States Alliance

The Clean Energy States Alliance (CESA) submitted comments focused on ensuring equitable access to energy storage benefits. CESA recommended prioritizing projects that address the needs of low-income and disadvantaged communities, emphasizing the potential for storage to reduce energy costs and improve resilience.

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[2] The organization formerly known as Northeast Clean Energy Council rebranded in 2024 to The Alliance for Climate Transition (ACT). Accordingly, this document refers to the organization as ACT.

CESA called for measures to ensure that underrepresented groups have a voice in the program's development. They suggested creating technical assistance programs to help community organizations prepare for energy storage projects, and advocated for including metrics to evaluate the program's social and environmental benefits.

Clearway Energy Group

Clearway Energy Group emphasized the need to align Maine's energy storage program with federal incentives to maximize economic benefits. Clearway supported the use of index storage credit mechanisms to stabilize revenue streams for developers while ensuring ratepayer value. They recommended optimizing project siting to enhance economic benefits and minimize environmental impacts, noting that careful site selection could avoid costly transmission upgrades, thereby improving project feasibility and ratepayer outcomes.

Clearway also emphasized the importance of balancing grid needs with Maine's clean energy goals, suggesting focusing on projects that integrate renewable generation and energy storage to deliver reliable, affordable, and clean electricity to Maine's residents.

Competitive Energy Services

Competitive Energy Services (CES) emphasized the need for cost-effectiveness for ratepayers by targeting energy storage projects that deliver maximum value. CES suggested focusing on areas with anticipated distribution and transmission upgrades, particularly the Portland region, where incremental storage could defer utility investments and reduce costs. CES recommended excluding existing projects from eligibility to ensure that funding supports new, incremental capacity.

CES opposed prioritizing storage deployment in rural areas with renewable curtailment issues, suggesting that such efforts would act as temporary fixes rather than addressing the underlying need for grid enhancements. CES also discouraged defining utility-scale storage strictly as front-of-the-meter systems, advocating instead for the inclusion of large behind-the-meter projects.

To maximize the federal incentives available under the IRA, CES recommended favoring projects on brownfield sites, which could qualify for bonus investment tax credits. CES proposed dividing the 200 MW program into three categories: behind-the-meter, targeted Portland deployments, and rural projects.

Form Energy

Form Energy advocated for prioritizing long-duration storage technologies, which are critical for addressing seasonal variability in renewable energy generation. Form Energy noted that conventional duration storage may not suffice as Maine moves toward 100% clean electricity. Form Energy recommended leveraging federal funding opportunities to pilot and scale innovative storage technologies.

Form Energy also stressed the importance of integrating long-duration storage into grid planning processes and creating pathways for these technologies to participate in competitive procurement processes.

Glenvale Solar

Glenvale Solar advocated for integrating energy storage with solar projects to maximize renewable energy utilization and grid benefits. Glenvale recommended designing the program to allow flexibility in project structures, enabling both solar-plus-storage configurations and standalone storage systems. They emphasized that storage should be used to reduce renewable curtailment.

Glenvale also highlighted the economic and environmental benefits of solar-plus-storage projects, such as job creation and long-term energy cost savings. Glenvale suggested that the program include provisions to support innovative business models, such as community-owned solar storage systems, which could offer both economic returns and increased energy resilience.

Key Capture Energy

Key Capture Energy emphasized the importance of simplifying permitting and interconnection processes to accelerate energy storage deployment. Key Capture Energy advocated for transparent timelines and clear guidelines to support efficient project implementation, emphasizing that administrative procedures and permitting can delay projects, leading to higher costs and lost opportunities for grid optimization.

Key Capture Energy also highlighted the need to incentivize long-duration storage, which provides critical reliability benefits, particularly as renewable penetration increases, and suggested that the program incorporate tiered incentives for different durations and prioritize storage technologies that deliver capacity during peak demand periods. Key Capture Energy also stressed the need to align storage initiatives with Maine's decarbonization goals, suggesting that energy storage could play a dual role in improving grid reliability and supporting emissions reductions.

To this end, they recommended pairing storage with renewable energy to optimize clean electricity delivery.

Longroad Energy

Longroad Energy advocated for aligning energy storage deployment with Maine's renewable energy and emissions reduction goals. Longroad emphasized establishing clear definitions of "preferred locations" to guide storage project siting and maximize grid benefits, and noted the potential for energy storage to alleviate grid congestion, particularly in areas with high renewable energy generation. Accordingly, Longroad Energy recommended targeting storage deployment to optimize the delivery of renewable electricity and reduce curtailment.

Longroad also emphasized the role of energy storage in supporting Maine's economic development objectives. By prioritizing projects that align with federal incentives, Longroad argued that the program could attract investment and create local jobs.

Maine Renewable Energy Association

The Maine Renewable Energy Association (MREA) emphasized the importance of aligning storage procurement with Maine's renewable portfolio standard (RPS) requirements and recommended competitive bidding processes to ensure cost-effective deployment of storage projects.

MREA's comments highlighted the role of energy storage in supporting renewable energy integration and noted that strategically sited storage could help stabilize the grid, reduce curtailment, and enhance the value of renewable generation.

MREA also stressed the need for clear guidelines to ensure storage projects contribute to Maine's long-term energy and environmental goals and proposed incentivizing projects that maximize both economic and emissions-reduction benefits.

Mason Station Redevelopment Company

Mason Station Redevelopment Company recommended repurposing brownfield sites for energy storage projects, noting that this approach would not only maximize federal incentives but also contribute to economic revitalization in Maine's communities. Mason Station Redevelopment Company's comments highlighted the importance of engaging local stakeholders in the planning and development of storage projects and emphasized that brownfield redevelopment could provide environmental remediation benefits while supporting clean energy goals.

Additionally, Mason Station Redevelopment Company suggested that storage projects on brownfield sites could serve as pilot programs for innovative business models. They recommended leveraging state and federal funding to attract private investment and accelerate project timelines.

New Leaf and Bluewave

New Leaf and Bluewave recommended prioritizing storage projects in underserved and low-income areas to address energy resilience and affordability gaps. Their comments highlighted the potential of energy storage to provide disaster preparedness benefits, particularly in communities vulnerable to extreme weather. They recommended program designs include resilience metrics, ensuring storage projects enhance local preparedness and energy security.

New Leaf and Bluewave also suggested that community ownership models could enhance public trust and engagement in energy storage initiatives. They proposed offering technical assistance to municipalities and community groups interested in developing storage projects, which could help bridge gaps in technical expertise and funding.

Nexamp

Nexamp emphasized the importance of multi-use applications for energy storage, noting the potential of pairing storage with solar projects to provide both grid services and customer benefits, such as bill reductions and increased resilience. Nexamp recommended clear and transparent interconnection policies to avoid delays that often deter storage deployment. Nexamp also suggested that Maine's program address the unique needs of distributed generation systems.

Additionally, Nexamp proposed that the program include incentives for innovative configurations, such as co-located solar-plus-storage systems, noting these projects offer a cost-effective path to achieving Maine's renewable energy and grid reliability goals.

Ocean Renewable Power Company

Ocean Renewable Power Company (ORPC) emphasized integrating energy storage systems with marine and other renewable energy technologies to diversify Maine's clean energy mix. They highlighted the potential of storage to support innovative solutions for Maine's unique geographical and energy needs. ORPC proposed pilot projects to demonstrate the viability of coupling energy storage with marine-based renewables, such as tidal and offshore wind energy.

Additionally, ORPC stressed the importance of collaboration between technology developers, regulators, and utilities. ORPC recommended creating pathways for emerging technologies to participate in competitive procurements.

Plus Power

Plus Power recommended a flexible approach to contract structures within the energy storage program to accommodate a wide range of storage technologies and configurations. Plus Power emphasized the importance of allowing developers to propose solutions tailored to Maine's unique grid needs, in particular to target areas with significant grid congestion and reliability challenges. Plus Power recommended focusing on regions like Portland and other high-demand areas where storage deployment could defer costly infrastructure upgrades.

Additionally, Plus Power suggested prioritizing storage projects that maximize federal funding opportunities. Plus Power noted that aligning project timelines with federal incentives would reduce costs for ratepayers and accelerate deployment.

RENEW Northeast and American Clean Power Association

RENEW Northeast and the American Clean Power Association emphasized the importance of regional coordination in energy storage planning. They noted that Maine's storage program could play a critical role in supporting broader New England grid stability and renewable energy integration.

They recommended aligning Maine's program objectives with those of neighboring states to maximize synergies and cost savings, suggesting that regional collaboration could enhance the value of storage investments and reduce overall program costs.

Rob Smart

Rob Smart emphasized the value of distributed storage systems in enhancing local energy resilience. He recommended prioritizing smaller-scale projects, particularly in rural and underserved areas, to reduce reliance on large, centralized transmission infrastructure. He suggested that distributed energy storage could empower local communities by providing backup power during grid outages and reducing energy costs for residents and businesses.

Rob Smart also highlighted the importance of public education to raise awareness about the benefits of energy storage and suggested that Maine's energy storage program incorporate incentives for local ownership models.

Ulteig

Ulteig underscored the importance of technical assistance in the successful deployment of energy storage projects. Ulteig also suggested state-funded studies to identify grid constraints and prioritize areas where storage could defer costly infrastructure upgrades, and creating pathways for collaboration between utilities, developers, and regulators to ensure efficient project implementation and maximize grid benefits.

Ulteig also highlighted the need for continuous evaluation of the energy storage program's outcomes. They suggested establishing metrics for reliability, resiliency, and cost-effectiveness to guide future program adjustments.

Opportunity for Comment

GEO released a Draft Assessment of Storage Procurement Mechanisms and Cost-effectiveness in Maine prepared by Synapse Energy Economics (hereafter the "Draft Assessment") and issued an Opportunity for Comment on March 12, 2024.[xxxii] The Opportunity for Comment requested feedback regarding the methodology, assumptions, and implications for program design contained in the Draft Assessment.

A primary area of interest was the consideration of allocating the statutory procurement authority for up to 200 megawatts of incremental energy storage capacity between transmission-connected or distribution-connected systems. GEO received 13 responses, all of which are summarized below and publicly available on the GEO's website.[xxxiii]

Alliance for Climate Transition

ACT emphasized the need for a clear and transparent procurement process to attract investment in energy storage and highlighted competitive bidding mechanisms to ensure cost-effectiveness and high-quality project selection.

ACT also highlighted the potential of storage to drive economic development, including job creation and technological innovation, and suggested incorporating criteria that prioritize projects with significant local economic benefits.

Additionally, ACT identified interconnection as a critical challenge and urged Maine to streamline processes for distributed and utility-scale storage projects.

Central Maine Power

CMP emphasized the role of energy storage in enhancing grid reliability and reducing operational costs by deferring costly transmission and distribution upgrades. CMP proposed integrating storage into long-term grid planning processes to optimize deployment and ensure alignment with clean energy goals.

Additionally, CMP highlighted the importance of regulatory clarity and flexibility in program design. They suggested that allowing utilities to actively participate in storage projects could enhance system reliability and improve program outcomes.

Clean Energy States Alliance

CESA focused on ensuring that Maine's energy storage program advances equity, recommending prioritizing projects that address the needs of low-income and underserved communities and emphasizing the potential for energy storage to enhance resilience and reduce energy costs. CESA also highlighted the importance of community engagement in project planning and implementation. CESA proposed creating pathways for local organizations to participate in energy storage development, such as offering technical assistance and financial incentives tailored to community projects.

Additionally, CESA advocated for integrating equity metrics into the program's evaluation criteria, arguing such metrics would ensure that the benefits of energy storage, such as increased reliability and cost savings, are distributed equitably.

Competitive Energy Services

CES recommended structuring Maine's energy storage procurement into three categories: behind-the-meter storage, transmission-connected storage in the Portland area, and rural front-of-the-meter storage. CES argued this approach would maximize ratepayer benefits by addressing specific grid needs, such as deferring capacity expansion in the Portland area and supporting smaller communities with strategic rural deployments. CES recommended excluding existing projects and focusing only on new, incremental capacity.

CES recommended that a significant portion of the program's capacity focus on areas like the Elm Street and South Portland load pockets, which CES described as facing significant grid congestion and rising transmission costs. By prioritizing projects in these zones, CES suggested transmission upgrades could be avoided, reducing future costs for ratepayers.

CES suggested maximizing federal incentives by prioritizing projects sited on brownfields or in energy communities, which can qualify for additional federal tax credits under the IRA. CES also recommended against allocating capacity to pilot programs or experimental technologies, advocating instead for commercially available systems.

Form Energy

Form Energy emphasized the role of long-duration energy storage in ensuring reliability and achieving Maine's clean energy goals. Form Energy argued that traditional short-duration storage may not fully address the state's seasonal and peak-demand challenges as renewable energy penetration increases. Form Energy recommended incorporating flexible procurement mechanisms that enable innovative solutions to participate in the program, as well as maximizing the use of federal incentives.

Additionally, Form Energy stressed the importance of aligning Maine's energy storage program with regional grid needs. Form Energy suggested that long-duration storage could play a pivotal role in reducing Maine's reliance on fossil fuels and contributing to New England's overall grid stability.

Glenvale Solar

Glenvale Solar emphasized the integration of paired solar and storage projects to enhance reliability and reduce curtailment, as pairing energy storage with solar could optimize the use of clean energy resources by storing excess generation for dispatch during peak demand periods. Accordingly, Glenvale recommended flexibility in program design to accommodate a variety of solar-plus-storage configurations.

Glenvale also advocated for including community-focused projects in the procurement framework, noting that paired solar and storage projects could deliver significant economic benefits, such as job creation and energy cost savings, particularly in underserved areas.

Steve Ingalls

Steve Ingalls recommended emphasizing small-scale, distributed energy storage projects to enhance community resilience and reduce strain on the grid. He highlighted that such projects could deliver localized benefits, such as backup power during outages and reduced transmission dependency. Accordingly, Steve Ingalls suggested prioritizing storage deployments in rural and underserved areas where infrastructure upgrades might otherwise be cost-prohibitive.

Steve Ingalls also emphasized the importance of public education and stakeholder engagement, noting that raising awareness about the benefits of energy storage would help garner public support and encourage community-driven projects.

Longroad Energy

Longroad Energy emphasized balancing upfront payments with performance-based incentives. Longroad argued that this approach would ensure developer participation while delivering long-term benefits for ratepayers.

Longroad also emphasized the potential of energy storage to improve grid reliability and reduce renewable energy curtailment, recommending deploying storage in areas with high renewable penetration to maximize system efficiency and emissions reductions. Longroad suggested that Maine could attract investment and increase cost-effectiveness by maximizing federal incentives.

Natural Resources Council of Maine, Union of Concerned Scientists, and Conservation Law Foundation

Natural Resources Council of Maine, Union of Concerned Scientists, and Conservation Law Foundation (hereafter "the environmental organizations") focused on aligning Maine's energy storage program with its climate and clean energy goals. They emphasized the importance of reducing greenhouse gas emissions and enhancing grid reliability through strategic storage deployments.

The environmental organizations recommended prioritizing storage projects that support renewable energy integration, particularly in areas with high levels of curtailment, arguing that such projects could maximize the value of Maine's renewable resources while reducing emissions.

Additionally, the environmental organizations highlighted the need for equity and transparency in program design. They suggested including metrics to evaluate environmental and social benefits to ensure that the program delivers broad, inclusive value.

Nexamp

Nexamp recommended multi-use energy storage applications, particularly those integrated with distributed solar projects, noting the potential for such systems to provide value not only to the grid but also to individual customers through lower energy bills and increased resilience.

Nexamp's comments highlighted the importance of addressing interconnection barriers to ensure timely project deployment. Nexamp recommended that Maine adopt transparent and streamlined interconnection policies to reduce delays and costs for developers.

In addition, Nexamp suggested incentivizing co-located solar and storage projects to maximize cost-effectiveness. They argued that these projects could simultaneously support grid reliability and contribute to Maine's renewable energy targets.

Plus Power

Plus Power supported a flexible program design that accommodates various storage technologies and configurations, and emphasized the importance of targeting areas with significant grid congestion to optimize system benefits and avoid unnecessary infrastructure upgrades.

Plus Power recommended structuring incentives to balance upfront payments with performance-based rewards, arguing that this approach would ensure that developers focus on delivering long-term value while maintaining financial viability for projects. Additionally, Plus Power stressed the need to align Maine's program with federal incentives, such as the IRA tax credits.

RENEW Northeast and American Clean Power Association

RENEW Northeast and the American Clean Power Association emphasized the importance of regional collaboration to maximize the benefits of Maine's energy storage program. They suggested that coordinating with neighboring states could enhance grid reliability and support the broader integration of renewable energy in New England. In addition, their comments emphasized the potential of storage to address regional challenges, such as transmission congestion and renewable energy curtailment, and support achievement of regional greenhouse gas reduction goals.

ReVision Energy

ReVision Energy advocated for integrating energy storage with distributed renewable energy systems, such as community solar projects. ReVision emphasized the potential for these systems to provide localized benefits, including resilience and cost savings for ratepayers.

ReVision also suggested prioritizing projects that deliver benefits to low-income and underserved communities, ensuring that the transition to clean energy is inclusive, and recommended incorporating educational initiatives to raise awareness about energy storage and its benefits. ReVision argued that public understanding and support are critical for the program's success.

Statutory Objectives

The Act requires GEO to evaluate designs for "a program to procure commercially available utility-scale energy storage systems connected to the transmission and distribution systems."[xxxiv]

Commenters including CESA, CMP, CES, Glenvale Solar, Longroad Energy, MREA, New Leaf and Bluewave, Nexamp, Plus Power, and the environmental organizations addressed "commercial availability" in some fashion, generally supporting the eligibility of "proven," "mature," or "commercially available" technologies and project configurations. GEO also relies on the Energy Storage Market Assessment to interpret this term. In general, commercial availability can be demonstrated in a number of fashions, including but not limited to deployment outside of research or demonstration contexts; prior viability for private commercial financing or creditworthiness; prior viability for commercial transactions among private-sector entities; or established third-party classification such as a high technology readiness level designation.

Based on the Energy Storage Market Assessment, existing deployments including in Maine, and the input of numerous commenters, GEO recognizes the use of lithium-ion battery technology and, for simplicity, assumes its use for subsequent analyses in this report. However, GEO does not recommend that bidding projects be precluded from proposing other commercially-available technologies. GEO interprets the legislative requirement for "commercially available" energy storage systems to preclude the program from seeking or supporting pilot-scale projects or piloting technologies.

In the RFI, GEO indicated that it interpreted "utility-scale" to mean energy storage resources connected in front of the meter. This interpretation is based on the separate authority established in Maine law for the Efficiency Maine Trust to incorporate energy storage into its programs, which broadly support customer-sited or behind-the-meter technologies. Some commenters also addressed the interpretation of the Act's requirement for the program to procure "utility-scale" energy storage projects. In its response to the RFI, CES indicated the program should support front-of-the-meter systems, and emphasized large utility-scale projects; however, in its subsequent response to the Opportunity for Comment, CES indicated support for behind-the-meter resources sited at commercial customer sites. Other commenters addressed utility-scale systems as connected to either or both the transmission and distribution systems but did not oppose GEO's interpretation.

The GEO continues to interpret utility-scale as referring to front-of-the-meter energy storage projects, and notes the Act specifically encompasses both transmission- and distribution-connected energy storage systems.

The Act further requires GEO to "consider programs that are likely to be cost-effective for ratepayers and that are likely to achieve the following objectives."[xxxv] The following sections address each of the "following objectives" stated in the Act, and the requirement that programs considered must be "likely to be cost-effective" is addressed in the subsequent Technical Analysis section.

Advance both the State's climate and clean energy goals and the state energy storage policy goals

The Act requires that GEO consider programs that are likely to "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."[xxxvi]

Maine law requires greenhouse gas emission reductions of 45 percent below 1990 levels by 2030 and 80 percent below 1990 levels by 2050.[xxxvii] Maine's Renewable Portfolio Standard requires that 80 percent of Maine's load be served by renewable energy resources by 2030.[xxxviii]

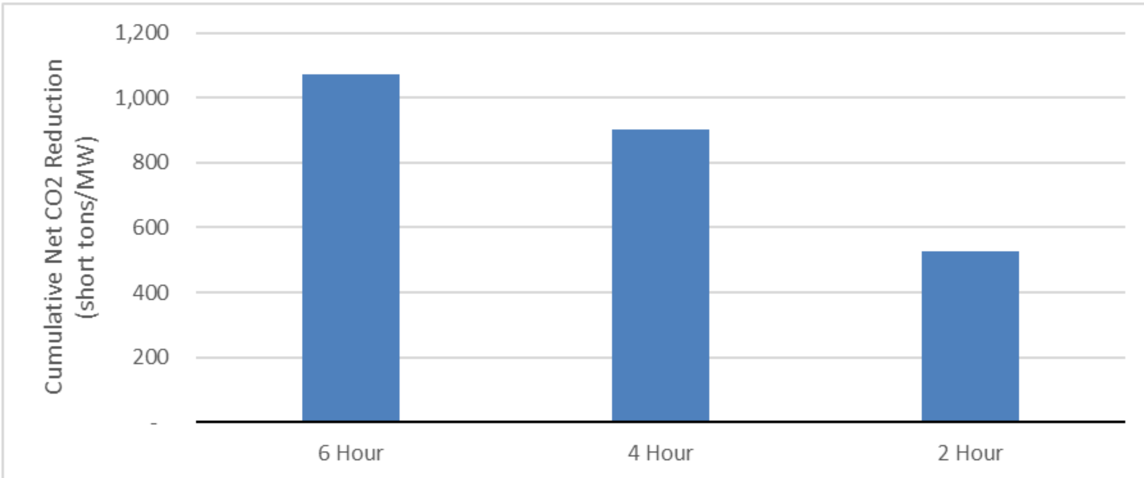
Stakeholders responding to the RFI and Opportunity for Comment emphasized that energy storage should complement renewables such as solar and wind to support the incremental delivery of clean energy while reducing transmission constraints.[xxxix] Specifically, RENEW Northeast commented on the ability of storage to reduce the price of Renewable Energy Certificates (REC) by increasing the demand for clean energy while minimizing curtailment and associated costs. Stakeholders also emphasized energy storage's ability to displace resources that emit greenhouse gases and other particulate matter.[xl] Stakeholders recommend incentivizing charging during hours when more renewables are generating energy and discharging during high-emission hours.[xli] CES and New Leaf/Blue Wave suggest the criteria for incremental delivery of renewable electricity should focus on whether operations of an energy storage system can reduce greenhouse gas emissions from marginal combustion sources in ISO-NE's generation fleet.

If wholesale energy prices strongly correlate with marginal emissions (i.e. prices are low in periods of low emissions while high prices coincide with high emissions), storage resources that optimize dispatch according to wholesale energy revenues are likely to reduce emissions. Namely, resources would charge during periods of low prices and low emissions, and discharge during periods of high prices and high emissions. Some positive correlation between wholesale energy prices and emissions in systems with high renewable energy penetration, such as Maine, would be intuitive since most renewables have zero marginal operating costs. However, currently, since gas units are frequently on the margin in ISO-New England, it is possible that optimizing dispatch purely according to wholesale energy market signals could potentially lead to increased emissions.

It is likely that well-sited storage will lead to long-term reductions in average emissions by enabling increased renewable energy penetration. However, it is important to understand the potential impact on greenhouse gas emissions given the program period and the legislative requirements. If economic dispatch (i.e. maximizing wholesale revenues) under current system conditions is reasonably likely to reduce greenhouse gas emissions, the program would not require further incentives beyond wholesale market signals to guide dispatch. However, if economic dispatch is reasonably likely to contribute to increased emissions, the program may require a countervailing mechanism to mitigate such increases.

An analysis of expected emission impacts under economic dispatch was conducted to determine whether a storage procurement program should include an emissions-based performance incentive, or whether economic dispatch was reasonably likely to also contribute to meeting emissions reduction goals. The analysis models systems of 2-, 4- and 6-hour durations, optimizing to maximize energy arbitrage revenues based on hourly wholesale market energy prices and hourly marginal emissions data.[xlii] Figure 7**Error! Reference source not found.** shows the expected cumulative net CO_2 impact over the 20-year modeling period (note that positive values indicate net reductions to CO_2).

Figure 7: Cumulative CO_2 emissions reduction over 20-year study period (positive values indicate reductions in greenhouse gas emissions).



While individual year-over-year dynamics, as well as factors such as specific nodal dynamics, may influence the short-run impacts of individual projects, this analysis demonstrates that battery systems that dispatch economically to maximize energy arbitrage revenues are likely to cause a cumulative net decrease in CO_2 emissions over the study period for all three modeled system durations. Furthermore, energy storage resources cannot currently make operational decisions about their emissions impacts without real-time data on marginal emissions to which they can respond, and New England does not currently have such data available.

Changes in supply and demand that may increase short-run marginal emissions can also drive down long-run emissions when considering the impact on structural change, including new generation, retirements, and transmission buildout.[xliii] One of the key benefits of energy storage is that it enables a greater level of renewable energy penetration, fundamentally changing the resource mix on the grid. Energy storage can help balance intermittent renewable energy by storing excess energy and releasing it when needed. This type of build impact is not captured in a short run marginal emissions analysis but has been quantitatively assessed and validated in other studies.[xliv] Furthermore, energy storage arbitrage is expected to reduce energy prices, which can help drive increased electrification, resulting in emissions reductions outside of the power generation sector.

Procuring an incremental 200 megawatts of energy storage on a timeline such that it could reasonably reach operation by 2030 will contribute to the state's achievement of its energy storage deployment goals.[xlv] Based on the current status of energy storage deployment in the state, and considering recent observed levels of attrition from comparable procurements in Maine and across the region,[xlvi] the GEO recommends utilizing the full authority for 200 megawatts in order to maximize the likelihood of successfully achieving the state's goals.

Provide one or more net benefits to the electric grid and to ratepayers

The Act requires that GEO consider programs that are likely to "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."[xlvii]

Improved reliability and improved resiliency

Stakeholders responding to the RFI and Opportunity for Comment emphasized the importance of maximizing transmission and distribution benefits along with emissions reduction. CES stated that benefits can vary depending on how a storage system is designed, how it is interconnected to the grid, location, and operational practices. CMP suggested that GEO define net benefits or "improved electric resiliency" as the reduction of the frequency and duration of outages during severe weather conditions and major storms. CMP also recommends that GEO "prioritize benefits such as reliability and resiliency based avoided costs, avoided energy, capacity costs, transmission and distribution benefits, monetized reliability, and energy storage's effect on wholesale energy prices." RENEW states that increasing energy storage capacity to lower peak demand will help Maine improve the reliability of power delivery to customers and may provide resilience under changing conditions. Some stakeholders also commented about potential benefits of siting storage in low-income or disadvantaged communities to the extent storage conveys location-specific benefits, such as improved reliability and resilience.

New Leaf and Blue Wave also suggested that in the context of Maine's geography and electric system, smaller energy storage facilities located closer to load will better enhance reliability and resilience. Furthermore, they note that, because Maine has a large pipeline of distributed solar in the interconnection queue and a transmission system that requires upgrades, distribution-connected storage can provide multiple values to ratepayers because it is located closer to the load (compared with transmission-connected storage).

GEO considered all stakeholder comments in assessing the value of net benefits through a robust cost-effectiveness framework to accurately account for multiple benefits provided by energy storage, as described below. Furthermore, wholesale market participation will promote operation that yields reliability benefits and likely net benefits to ratepayers. As more storage becomes operational, particularly in the long-term, that increase will likely have the larger scale impacts referenced by stakeholders.

Some stakeholders also noted that resilience and reliability can be supported through consideration of distribution-connected storage that enables microgrids; this would allow certain loads connected to the microgrid to "island" from the broader system during storms or other outage events. GEO agrees that microgrids can provide resilience and reliability. However, GEO did not specifically model the value of microgrids for two primary reasons. First, microgrids involve more than the deployment of storage – often renewables or fossil fuel generators must be deployed in conjunction with storage to operate a microgrid for more than a few hours. Second, utility investment to island portions of the grid during an outage must be considered, a cost which is highly project specific and likely unique to each utility's system.

Incremental delivery of renewable electricity to customers

Multiple stakeholders cited instances of congestion and associated curtailment of renewable energy resources currently operating in Maine as potential benefits of energy storage deployment. Because wholesale energy prices "price in" congestion, and certain renewable generators may even have negative-price appetites due to federal production tax credits, the GEO views a procurement mechanism that incorporates wholesale market participation as reasonably likely to result in projects that choose sites where wholesale energy prices are expected to vary sufficiently to enable energy market arbitrage.

Maximize the value of federal incentives

The Act requires that GEO consider programs that are likely to "maximize the value of federal incentives."[xlviii]

The primary federal incentive supporting deployment of energy storage is the Investment Tax Credit (ITC), established by Section 48 of the Inflation Reduction Act.[xlix] Initially, only co-located storage projects were eligible for the ITC, but the August 2022 passage of the IRA made stand-alone energy storage projects with a minimum capacity of 5 kWh eligible as well.

To maximize the value of the ITC, projects should begin construction before 2033. The ITC will begin to phase out in 2032, or when the United States meets 75 percent greenhouse gas emissions reduction from electricity generation. Projects can achieve a base tax credit of 30 percent of upfront capital costs if prevailing wage and apprenticeship requirements are fulfilled. If the project also meets certain domestic content sourcing requirements, the ITC is increased by 10 percent above the base 30 percent.[l] The IRS domestic content criteria requires two equipment sourcing conditions: (1) 100 percent of construction materials that are structural in nature and are comprised of iron or steel must have all steel and iron manufacturing processes take place in the United States, except metallurgical processes involving refinement of steel additives; and (2) a specified percentage of manufactured products (measured in product cost) that are components of the energy storage system must be produced in the United States. Current supply chain challenges may make it difficult to cost-effectively achieve the IRS requirements for domestic content, and the anticipated increased capital costs may not be offset by the additional 10 percent ITC credit.

The ITC is also increased by an additional 10 percent if an energy storage project is sited in an energy community.[li] An energy community, as defined in the IRA, includes brownfield sites, communities affected by coal mine and/or coal plant closures, and areas that have a minimum level of fossil fuel industry activity and an unemployment rate at or above the national average. There are no municipalities in Maine that qualify as an energy community under the second two categories of the definition.[lii] Therefore, storage projects developed in Maine would need to be sited on a qualifying brownfield property to qualify for the energy community bonus tax credit. Siting a battery project on a qualifying brownfield property could also provide local tax revenues and productive use of property that may not be developed or otherwise reused.

Other federal incentives may be available in the form of competitive grants for individual projects. Programs that may support energy storage projects include, but are not limited to, the U.S. Department of Energy's Grid Resilience and Innovation Partnerships (GRIP) Program;[liii] the U.S. Department of Energy's Energy Improvements in Rural and Remote Areas Program;[liv] and the U.S. Department of Energy's Energy Storage Demonstration and Pilot Grant Program.[lv] Competitive federal funding opportunities may open for applications at different times, with varying amounts of funding available for varying entities and specific project criteria.

A competitive solicitation is likely to incentivize bidders to pursue tax credits and any applicable competitive grants to maximize price competitiveness. Requiring participating projects to disclose anticipated or confirmed federal incentives ensures that (1) prospective bidders are notified that such incentives are expected to be considered, and (2) to the extent such incentives are assumed or incorporated into bids, any resulting federal requirements that may apply to the project can be understood during project selection.

Enable the highest value energy storage projects

The Act requires that GEO consider programs that are likely to "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."[lvi]

Projects in preferred locations

Stakeholders responding to the RFI and Opportunity for Comment raised a number of potential preferred locations that could be considered: low-income communities, export-constrained areas, microgrids, and areas of expected load growth (which could also defer distribution or transmission investment). There appear to be a range of stakeholder opinions on this issue. New Leaf and BlueWave suggested that the program not prescribe specific locations for development (e.g., certain circuits on the distribution system, an approach included in the Massachusetts Clean Peak Energy Standard). Conversely, RENEW suggested placing storage where it could address specific transmission constraints and increase reliability.

GEO agrees with stakeholders that suggest a solicitation need not include requirements for certain locations. GEO also considered whether there should be requirements for, or are incremental benefits associated with, storage that is physically co-located with renewable resources. At a bulk power system level, there are clear and significant capacity synergies associated with increasing deployment of storage and variable resources. Realizing these capacity diversity benefits does not, however, necessarily require physical co-location of resources. Benefits to physical co-location may include resiliency benefits to the extent that the system can be islanded or otherwise operated to provide resiliency benefits, interconnection optimization, or congestion management (i.e. reduced curtailment and energy arbitrage).

Realizing resiliency benefits from front-of-the-meter paired storage and renewables would require additional investments that are not examined in this report. Interconnection optimization and its potential benefits are best evaluated and realized by developers on a case-by-case basis. Therefore, GEO did not explicitly model storage co-located with renewables. Physically co-located projects, however, could still be eligible to participate in the recommended program.

Projects that can serve as an alternative to upgrades of the existing transmission system

New Leaf and Blue Wave proposed a program designed around distribution-connected storage registered as load reducers with ISO-New England, which would reduce the allocation of regional network service (RNS) charges to Maine ratepayers, a potentially significant value. CMP stated that energy storage should be considered as an alternate solution to transmission upgrades if it is the most cost-effective option.

There are two primary potential transmission-related benefits that can accrue to Maine ratepayers. As referenced above, the first potential benefit is reducing the portion of pool transmission facility (PTF) costs recovered from Maine ratepayers due to past incurred investment. This benefit does not require altering the trajectory of total PTF buildout, but, instead, reduces the portion of these costs paid for by Maine ratepayers relative to other New England electric customers. The second potential transmission benefit is reducing total transmission buildout. This benefit is more challenging to quantify, as it hinges upon the transmission planning process, both as it exists today and as it evolves in the future. In GEO's analysis, resources are modeled to discharge during coincident peaks, a mode of operation most likely to avoid future transmission buildout. Designing a program around this mode of operation can proceed today.

GEO also notes the separate statutory authority to examine non-wires alternatives administered by the non-wires alternatives coordinator retained by the Office of the Public Advocate,[lvii] and the Storage as a Transmission Asset process established through the ISO-New England Open Access Transmission Tariff[lviii] as alternative pathways for the deployment of energy storage that serves as an alternative to upgrades of the existing transmission system.

Projects of optimal duration

Most commercially available energy storage technologies can provide their nameplate power for four to six hours. Such durations can provide substantial value today and well into the future. For this reason, stakeholders recommended that GEO avoid a prescriptive approach to duration within procurement processes to leave space for that development. GEO analyzed multiple potential durations to examine this topic further, as discussed below.

GEO agrees with stakeholders that there is no need to be prescriptive about the duration of storage projects sought for procurement. A well-crafted program should provide incentives for storage dispatch that will yield benefits to ratepayers, allowing developers to make decisions about the configuration that will optimize value subject to the design of the program and other potential market revenues. The optimal duration is reasonably determined to be the duration of projects that yield the greatest net benefits.

Program Design Options

Storage incentive programs are becoming increasingly common as more states enact storage targets. Across the country, states use differing mechanisms, incentives, and programs to reach their goals. This section reviews potential procurement program designs and examines other states' assessments. GEO considered the program designs summarized in Table 3 to procure storage based on a review of existing state programs and responses to the RFI and Opportunity for Comment.

Table 3: Summary of key program parameters for program designs evaluated

	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	Third party and/or 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	At the operator/utility discretion depending on the purpose of procurement

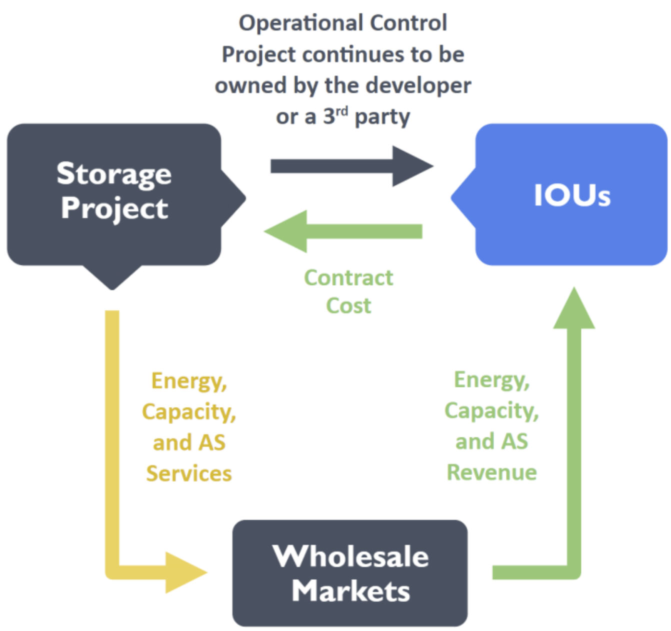
Tolling Agreements

An energy storage tolling agreement is a long-term contract that operates similarly to a standard tolling contract for traditional power plants or solar installations. 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 counterparty, the buyer of the system's output (often a utility in certain jurisdictions). The counterparty 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.[lix] The project owner receives a fixed payment called "a tolling fee" from the counterparty, often in the form of a capacity and variable O&M payment. A "partial tolling agreement" balances 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 EDC control on the most valuable days of the year.

Over the last several decades, utilities have used tolling agreements to finance battery energy storage systems in states where utilities are allowed to own and manage generation.[lx] In states where this is restricted or prohibited, tolling agreements have been more challenging to implement. In New York, electric utilities have been directed by the state to solicit storage through a tolling agreement called bulk storage dispatch rights.[lxi]

Figure 8 depicts a tolling agreement arrangement in which a utility (IOU) pays a third-party developer to deploy storage, retaining operational control. The project is dispatched to optimize wholesale market revenues, which ultimately flow back to the utility, avoiding certain costs that benefit ratepayers.

Figure 8: Illustrative tolling agreement framework[lxii]



Under a tolling agreement, ratepayers and developers face risks inherent to a fixed-price contract. Ratepayers risk overpaying for assets above the actual revenue requirement if the solicitation process is uncompetitive. On the other hand, developers face the risk of rising capital costs if there is a delay between when the contract and project come to fruition. There are additional risks related to ownership and delays in project development.

If structured effectively, tolling agreements can mutually benefit utilities, ratepayers, and developers. Tolling agreements can be especially beneficial in markets relying on bilateral agreements between utilities and individual power producers, namely restructured markets.[lxiii] In these contexts, the utility is often better positioned to optimize system dispatch, for instance to maximize investment deferral, whereas the IPP is well-positioned to operate and maintain the asset cost-effectively. This division of responsibilities can reduce costs and maximize either wholesale revenues or other system benefits, like distribution or transmission deferral opportunities, where utilities have greater visibility.

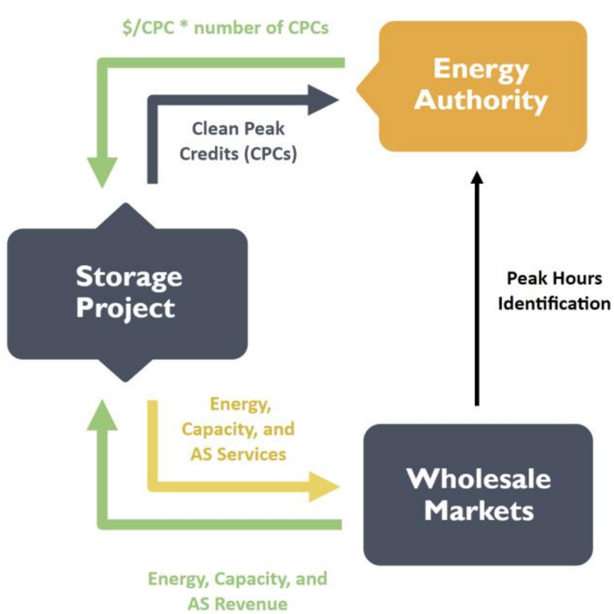
While tolling agreement structures are well understood and widely utilized, they do not necessarily incentivize optimal storage dispatch to maximize storage revenues. Nevertheless, these agreements are relatively simple to implement.

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. Storage projects receive compensation for discharging at pre-determined peak hours. Under this procurement mechanism, energy storage projects sell their Clean Peak Credits (CPC) to an offtaker, which could include a state energy authority or a load serving entity, depending on how the policy is designed. Storage must serve an increasing portion of load during peak hours. Depending on the design of the policy and other constraints, projects may also receive revenue from wholesale energy and capacity markets.

Massachusetts currently uses Clean Peak Energy Credits for storage procurement through the Clean Peak Energy Standard (CPS). Load serving entities in the state must regularly acquire a minimum quantity of Clean Peak Energy Certificates, which is intended to signify the amount of clean energy placed on the grid during peak hours.[lxiv] The Massachusetts CPS also includes various multipliers, which increase the volume of certificates produced, including one for production during the monthly coincident peak, defined as the highest net demand for electricity in a calendar month in the ISO-NE area.[lxv]

Figure 9: Illustrative Clean Peak Credit framework[lxvi]



NYSERDA's assessment of the Clean Peak Energy Standard in its Energy Storage Roadmap found that setting peak hours is highly complex and incompatible with the dispatch and bidding requirements in the wholesale market.[lxvii] It also raised concerns about the cost-effectiveness of this mechanism, as operational requirements at peak hours may limit alternative revenue sources and increase cost and uncertainty for developers. However, NYSERDA also noted that the procurement mechanism is likely to result in certainty in revenues, resulting in relatively low attrition.[lxviii]

Comments submitted by New Leaf and Blue Wave criticized the Massachusetts Clean Peak Credit Program design, specifically the Distribution Circuit Multiplier, which incentivizes projects to be located on heavily loaded circuits. According to New Leaf and Blue Wave, a program that is overly prescriptive of preferred locations "seems reasonable but, in practice, results in high upgrade costs for projects to interconnect." They recommend an incentive design with broader categories of preferred locations.

Other assessments of the Clean Peak Credit have found that the Massachusetts Clean Peak Standard could reduce greenhouse gas emissions and reduce infrastructure costs by allowing an increasingly large portion of peak demand to be served by local renewable energy sources (through storage charge and discharge) instead of greenhouse-gas-emitting resources.[lxix] However, lack of consideration for the marginal generation unit could misalign the mechanism with emission reduction goals. The current design of the Massachusetts Clean Peak Standard incentivizes charging impacts using the average grid emissions intensity during charging and discharging times. Therefore, the CPS does not capture changes in marginal operating emissions rates.[lxx] Energy storage resources can increase emissions if they charge when the marginal generation unit is emissions-intensive (such as natural gas or coal) and discharge when the marginal unit is less or equally emissions-intensive.[lxxi]

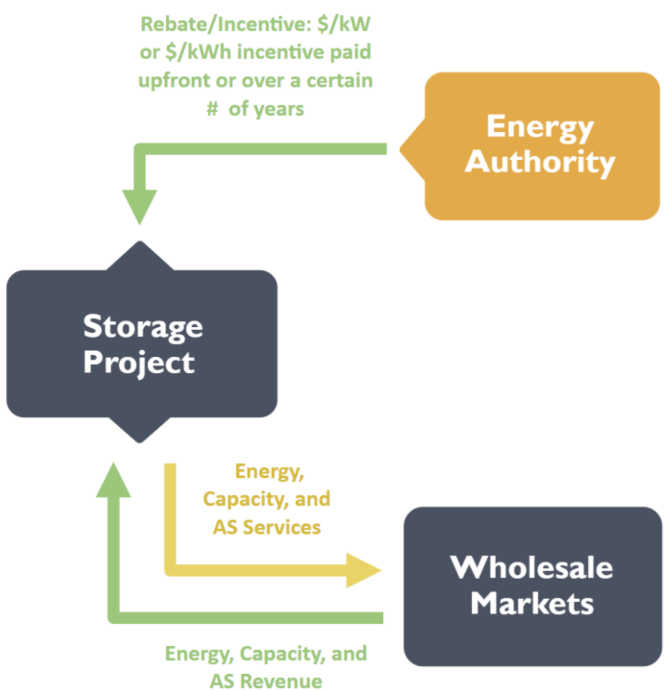
Upfront Incentives with Pay-for-Performance or Operational Requirements

Under a pay-for-performance mechanism, projects receive ongoing payments based on their ability to satisfy specified performance metrics. These metrics are often either based on the project's ability to dispatch during critical hours or on the net system emissions impact that the project'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-connected storage systems may have different performance criteria since they tend to provide different services to the grid.

Several states, including California, Connecticut, Massachusetts, New Hampshire, New Jersey, and Rhode Island, have either proposed or implemented storage programs with pay-for-performance elements. Efficiency Maine has also adopted such a program approach for behind-the-meter resources. Figure 10 illustrates the basic concept.

New Jersey has not yet implemented its Energy Storage Incentive Program (NJ SIP). Still, the Board of Public Utilities did release a straw program proposal in 2024, which is currently undergoing a stakeholder review process.[lxxii] Under the NJ SIP program proposal, NJ SIP incentives would be comprised of two main incentive payments. The first will be a fixed incentive, measured in dollars per kWh of maximum usable energy storage capacity and paid one time upon commercial operation. The second incentive will be a performance-based incentive applicable to benefits created through the storage system's operations.

Figure 10: Illustrative upfront incentive with pay for performance[lxxiii]



NYSERDA's assessment of the Upfront Incentive/Standard Offer option found that the design is relatively simple to implement and administer. The upfront incentive is also compatible with market signals and will allow projects to pursue revenue streams without conforming to specific dispatch requirements. However, when the administration sets levels, implementing the design becomes more complex. NYSERDA also found that fixed upfront incentives do not provide long-term revenue certainty to support financing. This is less attractive to developers and can potentially increase costs compared to other programs.[lxxiv]

A gap analysis can be conducted to identify uncertainty between wholesale market revenue and battery energy storage system financing. However, there remains risk of attrition since capital costs and the future market for battery energy storage systems are unknown and may be volatile. Because of this, investors are unlikely to finance a project with this risk. An alternative design would be to provide fixed payments over time rather than an upfront incentive. However, there is still uncertainty regarding market revenues, which can result in higher project costs and, therefore, increased costs to ratepayers.

Stakeholders, specifically CES, recommended a capacity-based construct with pay-for-performance incentives. CES recommends that the design "require [a] project owner to maximize wholesale market value from storage system operations and this value could be returned to ratepayers by designating an appropriate lead market participant."

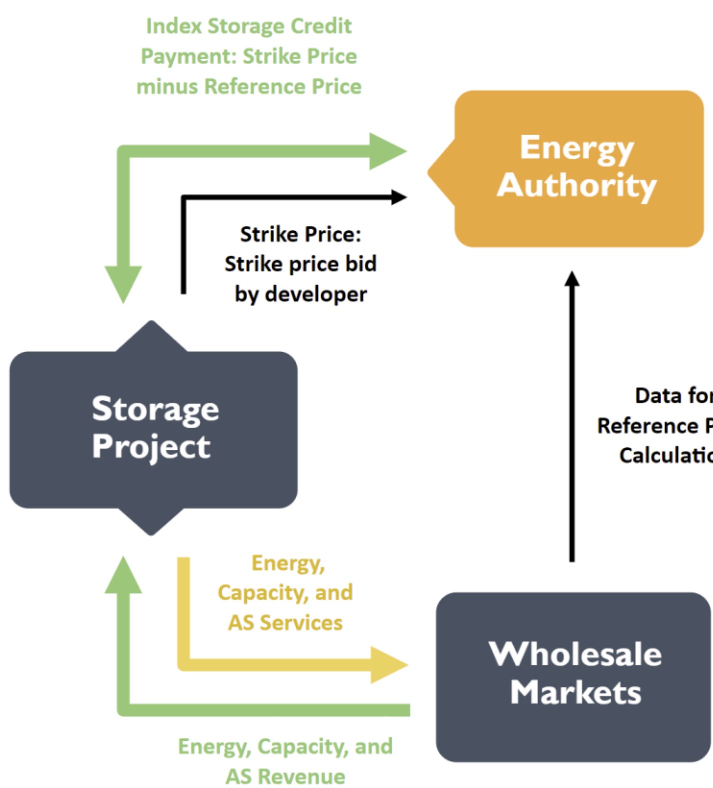
Index Storage Credit

An ISC mechanism establishes 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, the energy authority calculates a "Reference Price" 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 exceeds the Strike Price, meaning available market revenue exceeds the project's minimum needs, the project will pay the difference to the program administrator (EDC or state entity).

The Reference Price includes market revenues that are captured through the range of opportunities available to storage facilities, including energy arbitrage and capacity market revenue. However, awarded projects are not actually required to participate in any market. While projects have the autonomy to pursue actual revenues above or different than those indicated by the indices used to calculate the Reference Price, without any market revenue, the ISC payments would not be expected to make projects economically viable. This incentivizes projects to maximize market revenues.[3]

Figure 11: Illustrative Index Storage Credit mechanism[lxxv]



The primary use case for the ISC mechanism to date is in the NYSERDA Energy Storage Roadmap. NYSERDA's proposal to procure 3 gigawatts of bulk storage through a new ISC mechanism is an important roadmap element. In June 2024, the

[3] This program structure is analogous to the "Index REC" approach currently used in NYSERDA's offshore wind and onshore large-scale renewables procurement.

New York Public Service Commission adopted NYSERDA's recommendation to utilize an ISC mechanism, and directed NYSERDA to procure up to 3 gigawatts through annual procurements.[lxxvi]

Stakeholders raised several concerns about the ISC mechanism in their comments to GEO. Several raised concerns about the program's complexity, both in terms of administrative burden as well as the potential room for error when calculating the reference and strike prices. CMP highlighted the difficulty of forecasting long-term revenue streams appropriately and accurately for a technology that is still a nascent entrant to wholesale power markets. CMP noted that this could pose a long-term risk since uncertainty around available market revenues could potentially lead to greater deltas between the Strike Price and Reference Price than expected. CES stated that the mechanism may be time-consuming and costly to manage and that a daily reference price construct creates room for potential mistakes.

One key consideration centered around the inability of resources north of the Surowiec interface in Maine to qualify for capacity payments in ISO New England's Forward Capacity Market since 2021. Due to transmission constraints in the state, resources located north of this interface are not considered deliverable to the rest of the region. According to New Leaf and Bluewave's comments, capacity payments can account for 25 to 40 percent of a transmission-scale storage system's wholesale revenues in other states. Without capacity market revenue, the Reference Price will likely generally be significantly lower than the Strike Prices, which would increase the amount of financial support required.

An ISC mechanism has some advantages. Under an ISC mechanism, battery energy storage system operators have incentive to optimize the storage value and follow wholesale market price signals. The mechanism is theoretically also cost-efficient as it provides the correct financing opportunities for owners without ratepayers bearing high costs. However, while a portion of the revenue stream is "de-risked," developers will still likely bear substantial market risk. There could be a significant mismatch between the stipulated reference price and wholesale market revenues if certain revenue streams are not represented accurately in the reference price calculation. Furthermore, there is uncertainty around the extent to which revenues are hedged and how expensive an ISC program would end up being for a state agency to administer, since long-term market-based revenues are difficult to forecast.[lxxvii]

Recommended Procurement Design

GEO performed a qualitative assessment of the procurement mechanisms discussed above to evaluate them against the criteria established in the Act. Table 4 summarizes this qualitative assessment. Based on this assessment, the GEO selected an upfront incentive with pay-for-performance program design as the most consistent with the objectives of the Act.

The Act requires GEO the "evaluate designs for a program to procure commercially available utility-scale energy storage systems connected to the transmission and distribution systems."[lxxviii] GEO recognizes, based on numerous stakeholders' responses to the RFI and the Opportunity for Comment, that a single program design is unlikely to be optimal to support energy storage projects connected to the transmission system and energy storage projects connected to the distribution system. However, GEO did not determine that entirely different program structures were necessary to procure both transmission-level and distribution-level storage. In other words, GEO recommends two separate upfront incentive/pay-for-performance procurement programs: one for transmission-level projects, and one for distribution-level projects.

Table 4: Summary of program design options compared to objectives of the Act

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. avoided costs.	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. avoided costs.	Depends on contracting terms. May lower financing costs by mitigating market risk.
Advance the State's climate and clean energy goals	Optimizing dispatch based on wholesale prices is reasonably likely to decrease greenhouse gas 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 development.	Depends on operation of the asset.
Advance the State's energy storage policy goals	This mechanism is simple and transparent, which would encourage participation.	The relative implementation of complexity may be a barrier to storage policy goals.	Can over-constrain dispatch such that key hours may not be served.	Well-understood contract structure.

Improved reliability and resiliency	Resources can be paid based on their ability to dispatch during critical hours.	Vendors do not have incentives to improve reliability or resiliency without additional payment.	Can over-constrain dispatch such that key hours may not be served.	Resources can be paid based on their ability to dispatch during critical hours.
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 bidders will be incentivized to price in and seek out federal incentives.	Neutral.	Neutral.	Neutral.
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.	Neutral.	Neutral.	Adds less incentive to maximize wholesale revenues.

Transmission-Connected Procurement Mechanism

GEO recommends an upfront incentive coupled with a pay-for-performance mechanism designed to achieve avoided transmission-system costs. Resource owners would retain flexibility to maximize wholesale market revenues during non-event hours. While avoided transmission costs (primarily pool transmission facilities, or PTF) represent significant potential savings to Maine ratepayers, individual resource owners cannot directly monetize these benefits. Thus, providing an incentive to operate in such a way intended to capture avoided transmission costs can produce net benefits to ratepayers. Further, providing flexibility for resources to earn wholesale market revenues reduces the required incentive level.

Transmission planning is complex, which complicates efforts to develop a storage dispatch approach that will yield avoided PTF costs. While the methodology for estimating some benefits is reasonably consistent with realizing avoiding costs, for example reducing the RNS charges borne by Maine ratepayers through reducing Regional Network Load, there is not a similarly straight-forward approach to estimating avoided future (marginal) PTF costs, though the methodology employed later in this report provides a reasonable estimate.

Under this procurement mechanism, participating resources would receive payments tied to their performance during event windows. These events would be determined either by a third party or by the energy storage owner. In either case, the risk of nonperformance would rest with the energy storage owner.

During non-event hours, resource owners would be free to maximize revenues through wholesale markets. By creating a competitive solicitation tied to proposed incentive levels, bidders with the lowest costs, most optimistic projections of wholesale market opportunities, and greatest confidence in their ability to operate the battery to capture all of the revenue opportunities would be positioned to submit the most competitive bids while also providing the greatest value to ratepayers.

Distributed-Connected Procurement Mechanism

As with avoided transmission costs, avoided distribution costs yield a large potential source of savings to ratepayers. However, storage resources cannot directly monetize these benefits, thus necessitating a mechanism to incent the development and operation of energy storage resources to achieve distribution system savings. A partial tolling agreement or a pay-for-performance mechanism, which would provide fixed payments to a third-party and distribution system-optimized dispatch, is likely the optimal procurement mechanism for distribution-connected storage, based on both the criteria of the Act and the particular needs of the distribution-connected use case.

While data needed to operate storage in ways that benefit the bulk power system (e.g., energy prices, data needed to produce load forecasts) is publicly available, a similar level of transparency does not exist for the distribution system. More specifically, only distribution utilities have direct visibility into current loading conditions on their system. Resources dispatched to realize benefits at the bulk power system level work over larger geographical areas than do those at the distribution level. This makes it less critical for every single resource to perform during every single transmission-level event. For example, if a fleet of energy storage resources located in Maine is being dispatched to try to reduce peak net load, and a subset of these resources do not perform during peak hours, the value achieved is reduced proportionally, but not lost altogether. If, however, a single energy storage resource is installed on a distribution feeder to manage peak loading on that feeder, failure of that single resource to perform eliminates the potential value entirely. This inability to distribute risk over a larger portfolio of resources may tend to favor partial tolling agreements over pay-for-performance, to the extent that tolling agreements may involve a penalty for non-performance rather than simply forgone revenue for the project owner.

Distribution utilities are currently in the best position to understand preferred locations for storage to avoid or defer future investments and benefit consumers. However, there still would be no guarantee of those consumer benefits. Unlike with the transmission system that is planned and overseen by a regional organization with public-facing data, distribution systems are managed by utilities who maintain relevant data and are accountable for system reliability. The value of distribution-connected storage is unlocked when energy can be delivered during specific hours, and utilities are the actors with the data and infrastructure control to do this. Any other program design or procurement mechanism will be limited in its ability to unlock this key value to the distribution system, making other procurement mechanisms for distribution-connected storage impractical or imposing undue risk on ratepayers regarding the degree to which benefits are attained. However, procuring distribution-connected storage optimized only for avoiding transmission costs may itself be sufficiently cost-effective.

As discussed in greater detail in the cost-effectiveness analysis below, assuming the operation of storage in distribution system planning and investment is ensured, distribution-connected storage dispatched to manage winter peaks on certain circuits is likely to be highly cost-effective. During the remaining months, storage resources can earn a performance incentive by responding to transmission peak events, similar to the mechanism for transmission-connected resources. These events are intended to reduce Regional Network Service (RNS) charges. Because the intention is to affect RNS charges, however, these resources are dispatched based on projected monthly peak loads for the state of Maine.

Resources participating in wholesale markets may not be able to impact RNS charges. More specifically, Generator Assets do not affect the calculation of Monthly Regional Network Load (effectively, the monthly peak load which is multiplied by the applicable RNS rate to calculate monthly PTF charges).[lxxix] As a result, resources can participate directly in energy markets or provide RNS benefits, but they cannot accomplish both. Given that RNS benefits exceeded the wholesale market revenue that resources could earn outside of winter months, it is assumed that the distribution-connected resources would act as load reducers and not participate directly in wholesale markets.

Cost-effectiveness and Ratepayer Impact Analysis

The Act requires the GEO to "consider programs that are likely to be cost-effective for ratepayers."[lxxx] For transmission-connected storage, the modeling primarily optimized storage dispatch around reducing future PTF projects by discharging at the system peak each year. For other hours, it sought to maximize revenues in the wholesale market. The modeling optimized distribution-connected storage to defer or avoid distribution peaks in the winter, while in other seasons storage was used to reduce RNS charges, discharging during Maine's monthly peak. The optimized hourly dispatch (charging and discharging) informed both estimated market revenues and cost-effectiveness.

Event windows

Modeling both transmission and distribution-connected resources requires establishing hours of events associated with the performance-based incentive. For transmission-connected resources, while future PTF buildout is likely driven primarily by annual coincident peaks, GEO assumes that events are also called to coincide with monthly peaks, to increase the probability that storage would affect transmission buildout. For distribution-connected resources, events are modeled based on monthly coincident peak hours during non-winter months.

Notably, these events require consideration of the ease with which a program administrator or storage operator could correctly predict coincident peaks. GEO adopted assumptions, by month and year, for the duration and frequency of events that would need to be called in order for an administrator to have a high probability of accurately calling all or most coincident peak hours. Current pay-for-performance programs, such as ConnectedSolutions and Energy Storage Solutions, generally have a maximum event duration of 3 hours. Factors such as flattened loads resulting from storage deployment and more flexible loads (responding to increasingly granular time-varying rates), increased deployment of variable resources, and increasingly volatile weather may make accurately predicting coincident peaks more challenging.

Based on these factors, a review of historical ConnectedSolutions event calls, and a review of unserved load hours associated with AESC modeling, assumptions were developed for the duration and frequency of events, as represented in Table 5 and Table 6 below. For 8760 modeling (a modeling method which considers hourly generation and load values across all 8,760 hours of the year), the top *n* hours in a given month were identified, where *n* is represented by the number of events in the pertinent month and year. The event durations below were applied to these selected peak hours.

Table 5: Count of Modeled Events per Month

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Jan	3	3	3	3	3	3	3	3	3	6	6	8	8	8	8	8	8	8	8	8
Feb	3	3	3	3	3	3	3	3	3	6	6	8	8	8	8	8	8	8	8	8
Mar	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Apr	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
May	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Jun	6	6	6	6	6	6	6	6	6	4	4	4	4	4	4	4	4	4	4	4
Jul	6	6	6	6	6	6	6	6	6	4	4	4	4	4	4	4	4	4	4	4
Aug	6	6	6	6	6	6	6	6	6	4	4	4	4	4	4	4	4	4	4	4
Sep	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Oct	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Nov	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Dec	3	3	3	3	3	3	3	3	3	6	6	8	8	8	8	8	8	8	8	8

Table 6: Event Duration (Hours)

	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
Jan	3	4	4	4	4	4	4	4	4	4	4	6	6	6	6	6	6	6	6	6
Feb	3	4	4	4	4	4	4	4	4	4	4	6	6	6	6	6	6	6	6	6
Mar	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Apr	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
May	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Jun	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Jul	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Aug	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Sep	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Oct	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Nov	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Dec	3	4	4	4	4	4	4	4	4	4	4	6	6	6	6	6	6	6	6	6

The duration of events has important implications for the storage configurations developers would select and how they would generate their bid price. The frequency of events, as it may affect opportunities to earn wholesale market revenues, would also affect bid prices. Therefore, refining these values is important.

The benefits that accrue to ratepayers, and the market revenues to the asset owners/operators of a storage resource, are in large part a function of the hourly dispatch schedule for the resource over the modeling period. Given the procurement mechanism selected, dispatch was simulated that aligns with an expectation of how asset operators seek to maximize revenues, while adhering to technical and contractual limitations and requirements.

The following sections describe the market revenue streams modeled and the assumptions related to quantifying them, followed by key assumptions and methodology underlying the dispatch strategy and attaining market revenues.

Energy Revenues

Energy storage resources can charge during low-priced hours and sell the stored energy during hours when prices are higher, thus arbitraging the price differentials in the ISO-NE wholesale markets. Accordingly, the potential energy arbitrage revenues will be driven in large part by the assumed energy prices during the modeled years.

The assumed energy and reserve prices are based on future price trends from AESC 2024.[lxxxi] However, given that the AESC projections have less volatility than observed in recent market activity, the average month to hour ratios of prices from AESC and a historical year (2021 in this analysis) were used to scale the hourly price series to develop projections for energy prices.

FERC has recently approved market changes proposed under the Day-ahead Ancillary Services Initiative (DASI), which among other impacts, is likely to put upward pressure on day-ahead energy prices.[lxxxii] The DASI-related market changes will be in effect starting March 2025. As such, the impacts of DASI are not captured in actual historical prices. Accordingly, hourly profiles from ISO-NE's simulation data for 2021 from the DASI impact analysis were used to develop energy price projections.[lxxxiii]

Modeled prices were also modified based on assumed dispatch (described below) to estimate day-ahead market revenues for the energy storage resource. These revenue estimates were subsequently adjusted to include two additional potential revenue streams for energy storage resources:

Balancing revenues: Energy storage can earn additional revenues in the real-time market by deviating from their day-ahead positions in response to unforeseen circumstances, which could include price spikes/periods of low prices in the real-time market. As such, a 5 percent adder was incorporated to reflect these additional balancing revenues.[lxxxiv]

Reserve scarcity revenues: As noted above, the analysis assumes an increase in the number of reserve scarcity events (i.e., PFP events) as renewable penetration increases. This assumption would increase the real-time and day-ahead prices due to the activation of administrative shortage pricing set by the Reserve Constraint Penalty Factor (RCPF) during these intervals. The potential increase in the annual revenues for storage resources was estimated as the product of expected number of reserve scarcity hours in a year and the RCPF corresponding to shortage of 30-minute reserves (thirty-minute operating reserves or TMOR).[lxxxv]

Spinning Reserves

In addition to energy arbitrage, energy storage resources can earn revenue by selling 10-minute spinning reserves (i.e., Ten-Minute Spinning Reserves, or TMSR, which is typically the more valuable of the three existing reserve products). As such, storage resources face a choice between selling energy and reserves in many hours of the day. The value of revenues from the reserve market in ISO-NE is likely to increase because, as discussed above, the ISO created a day-ahead market for three reserve products, which is expected to increase compensation for flexible resources in the day-ahead market. Under DASI, ISO-NE has developed several new day-ahead ancillary services products (structured as call-options on energy) whose procurement will be co-optimized with that of energy.

In addition to reserves, battery storage resources can sell frequency regulation. However, the volume of batteries entering the market is likely to significantly exceed the procured quantity for this product.[lxxxvi] Hence, it is generally expected that a battery resource's revenues from the regulation market will decline to an insignificant level in the near term. Accordingly, revenues from the regulation market for this analysis were not modeled.

The demand for other ancillary service products is also considerably low relative to the volume of storage resources that are projected to enter the ISO-NE market. Nonetheless, revenues from the reserve market were modeled because demand for ancillary services is likely to increase in the future as an increasing portion of the load is served by intermittent resources. ISO-NE and other wholesale market operators in the region are considering additional ancillary service products that will support mid- to longer-duration storage resources as the resource mix continues to evolve

Therefore, TMSR prices from ISO-NE's DASI impact study were used, adjusted to reflect future conditions using the ratios used for energy price projections, and scaled down further to reflect a preference for longer-duration storage resources in the future. Specifically, it is assumed that 6-hour resources will be able to realize the full price while 2-hour and 4-hour resources will be able to realize only 33 percent and 67 percent, respectively, of the reserve price in any given hour in the future.

Capacity Revenues

Energy storage resources in Maine can also earn revenues from the capacity market operated by ISO-NE. In ISO-NE, the capacity market compensation is comprised of the base payment based on the Forward Capacity Market (FCM) price and the resource's Capacity Supply Obligation (CSO), and a performance payment (under the Pay-for-Performance or PFP framework), which provides payments under scarcity conditions.[lxxxvii] Resources in much of Maine have historically not been able to qualify for the FCM due to limited transfer capability. Nonetheless, these resources may still be able to realize PFP revenues.

To the extent that a resource could qualify for a CSO, the analysis evaluated the trade-off between storage either (a) taking on a CSO or (b) operating without a CSO and instead relying on higher PFP payments. It was assumed that the resource would maximize its expected capacity revenues between these two options each year.

ISO-NE is in the process of finalizing its resource capacity accreditation (RCA) and other capacity market reforms, which could have considerable bearing on the clearing prices, accredited capacity, and, ultimately, the capacity revenues for energy storage resources. Recent data from analysis carried out by ISO-NE and other entities suggest substantial impact on the qualified capacity of storage (most notably in the winter season) due to the RCA reforms, particularly for shorter-duration resources.[lxxxviii]

Capacity revenue estimates were based on the following assumptions:

- Capacity prices from counterfactual 6 of AESC 2024, which removes the effect of behind the meter battery storage on market prices.
- Seasonal marginal reliability impact (MRI) (effectively, the percent of nameplate capacity that is compensated through the FCM) values of 2, 4, and 6-hour storage resources.

Assumed seasonal MRI values are provided in Table 7.

Table 7: Seasonal marginal reliability impact of storage resources assumptions

Year	2-hr Storage		4-hr Storage		6-hr Storage	
	Summer	Winter	Summer	Winter	Summer	Winter
2027	1	1	1	1	1	1
2028	0.62	0.37	0.87	0.50	0.91	0.63
2029	0.57	0.33	0.82	0.47	0.90	0.61
2030	0.52	0.30	0.77	0.45	0.89	0.59
2031	0.46	0.27	0.73	0.42	0.87	0.57
2032	0.41	0.23	0.68	0.39	0.86	0.55
2033	0.36	0.20	0.64	0.37	0.85	0.53
2034	0.31	0.17	0.59	0.34	0.84	0.51
2035	0.26	0.14	0.54	0.32	0.82	0.50
2036	0.26	0.13	0.54	0.30	0.82	0.47
2037	0.26	0.12	0.54	0.28	0.81	0.44
2038	0.26	0.11	0.53	0.26	0.80	0.41
2039	0.26	0.10	0.53	0.24	0.80	0.38
2040	0.26	0.10	0.52	0.23	0.79	0.36
2041	0.26	0.09	0.52	0.21	0.78	0.33
2042	0.25	0.08	0.52	0.19	0.78	0.30
2043	0.25	0.07	0.51	0.17	0.77	0.27
2044	0.25	0.07	0.51	0.16	0.76	0.25
2045	0.25	0.06	0.50	0.14	0.76	0.22
2046	0.25	0.05	0.50	0.12	0.75	0.19

Assumptions for the number of reserve scarcity hours during which the PFP payments and penalties would apply based on:

- the annual average number of scarcity hours since the inception of the PFP framework since 2018,
- the increase in hours of shortage pricing relative to the increase in the renewable penetration in other markets with large penetration of intermittent renewable resources, and
- projected growth in renewable penetration in ISO-NE in AESC 2024.

Performance of storage resources during hours of scarcity in absolute terms, and in relation to the average performance of storage resources during recent PFP events, is likely to increase in duration and shift toward a greater number of winter events in the future.[4]

Transmission-Connected Storage Analysis

For transmission-connected storage resources, an hourly dispatch strategy was developed that prioritized

1. responding to discharging during critical hours, followed by
2. maximizing energy and ancillary services revenues during all other hours.

Hourly load data from AESC 2024 were utilized to identify the hours during which discharging is most likely to be beneficial to the transmission system, specifically, during monthly system peak hours. To reflect the challenges associated with accurately predicting the peak monthly hour, multiple events per month were modeled, varying by month and generally increasing over time. Similarly, events of different duration were modeled, starting at two hours and increasing over time to up to six hours in winter months (starting in 2030). In establishing the assumed frequency and duration of events, projected trends in the timing, duration, and frequency of scarcity events developed as a part of the AESC process were reviewed. In general, the increasing difficulty in projecting peak load hours is a reflection of increasing variable and dispatchable distributed energy resources (including flexible load), which was incorporated into the modeling assumptions.

As noted above, the dispatch model prioritized dispatch calls during event windows, requiring the battery to discharge during these hours at the maximum possible levels, subject to power rating and duration constraints. During the other hours, projected energy and reserve prices were utilized (treating them as the proxy for day-ahead prices) to estimate the optimal dispatch schedule, subject to several operational constraints.[5]

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[4] Under the PFP framework, the compensation/penalty to a resource during a scarcity hour is determined as: PPR x (A – Br x CSO), where: (a) PPR – payment performance rate, (b) A – actual energy/ reserves provided by the resource during a scarcity event, (c) Br – balancing ratio or the resource's share of the system requirement during the scarcity event, and (d) CSO – the resource's capacity supply obligation.

5 See previous section for the methodology used to derive energy and reserve prices. In estimating the reserve revenues, reserve prices were adjusted down by 75 percent to account for the closeout charges that

Dispatch of 2-, 4- and 6-hour batteries was modeled assuming that each battery will be dispatched up to one cycle a day and has a roundtrip efficiency of 86 percent.

Duration

Energy storage projects of 2-, 4- and 6-hour duration were modeled. The majority of capacity from recent entrants (approximately 85 percent) and projects in advanced stage of development in New England are 2- and 4- hour batteries. Nonetheless, given the incidence of longer-duration potential loss of load events from reliability modeling in the later years, the analysis includes 6-hour resources.

Location

For the purpose of this analysis, dispatch was evaluated using the prices from the Maine hub. Given the transmission topology and location of supply resources, Maine experiences congestion in several different load pockets. Revenue potential for batteries in several locations across Maine were evaluated utilizing 5-year historical pricing data from representative nodes that considered the following constraints: Downeast export, Keene Road export, Wyman hydro export, Rumford export, Orrington-South, and Surowiec-South. It was observed that the variation in potential revenues was less than 7 percent.

Distribution-Connected Storage Analysis

To analyze the likely cost-effectiveness of distribution-connected resources procured as described above, the model utilized data from the National Renewable Energy Laboratory (NREL) "ResStock" dataset[lxxxix] and Synapse's proprietary heat pump load model, based on a weather year that aligned with assumptions in AESC 2024.

Distribution feeders serving residential load with varying levels of space heating electrification were simulated. The analysis focused on residential load profiles because this class largely drives noncoincident peak load in Maine, and thus is likely to be responsible for driving distribution system investments on most portions of the distribution system in the near-term.[xc]

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

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resources taking on a reserve obligation will incur in the real-time market (i.e., when the real-time prices exceed the Strike Price, as defined by ISO-NE). In its DASI impact analysis, ISO-NE estimated the total closeout charges to be approximately 75 percent of the total charges associated with purchase of ancillary services in the day-ahead market under DASI.

from December through February to be available to respond to dispatch calls to address the distribution system peak. For the remaining months, resources were modeled responding to calls similar to those simulated for the transmission-connected resources, except that the events were tied to monthly Maine system peaks as opposed to ISO-NE system peaks because the targeted benefit for these events is RNS savings. Resources were not assumed to take on a capacity supply obligation, in order to ensure that during winter months the battery can be dispatched to meet the requirements of the distribution system. Further, taking on a capacity supply obligation would likely require the resource to operate as a Generator Asset, which would eliminate potential RNS savings.

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, this analysis 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, it was assumed that 2-hour resources will yield a kilowatt deferral equal to 25 percent of nameplate capacity; 50 percent of nameplate capacity for 4-hour resources; and 75 percent for 6-hour resources. These assumptions are based primarily upon a review of the simulated feeder data, which included several significant peaks occurring during winter months, generally lasting approximately 8 hours.[xci] 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 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 likely to be cost-effective.

In addition to avoided distribution and RNS costs, potential energy arbitrage revenue for these resources was considered. Given the potential incremental value and some of the potential implementation challenges, modeling of arbitrage outside energy markets was omitted. As previously discussed, these resources would not participate in wholesale energy markets directly, as doing so would eliminate the potential for RNS benefits.

In modeling the distribution-connected resources, it was assumed they would be subject to a retail tariff for charging. CMP filed a request for approval of a wholesale distribution access tariff (WDAT) with FERC on February 1, 2023, in Docket ER24-1177. WDATs are intended to set rates for and govern the terms of service for distribution-connected resources that primarily participate in wholesale markets (in CMP's case, specifically designed for energy storage). However, because it is assumed that distribution-connected storage resources would not participate in wholesale markets, these resources would likely not be eligible to take service under the WDAT.

Therefore, it is assumed that CMP's retail "B-ES" rate, specifically, LGS-P-TOU, would apply to storage resources.[xcii] This rate includes time-varying demand charges, flat volumetric charges, and a fixed monthly charge. While there are a number of differences in rates between the current retail B-ES rate and the filed WDAT, perhaps the most impactful is the difference in the fixed monthly service charge (which was $9,661 per month under the retail tariff and $890 under the proposed WDAT at the time of this analysis).

Cost-Effectiveness Framework

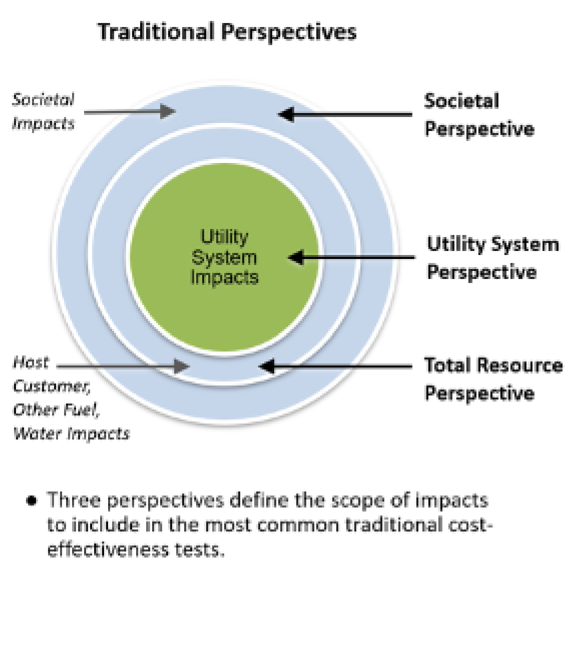
A benefit-cost analysis is a systemic approach for assessing the cost-effectiveness of investments by comparing their benefits and costs to achieve a benefit-cost ratio. This ratio is calculated based on all of the relevant benefits and costs in a project's lifetime to see how benefits compare with project costs. This process is widely used to assess investments in the energy system, and in other sectors, to assist with decision-making and enable easy comparisons among investments and programs.

The National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (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 benefit-cost analysis principles and should represent the "regulatory perspective," which is meant to represent the views of legislators, commissioners, and other relevant decision-makers.[xciii] Jurisdiction-specific tests focused on the regulatory perspective evaluate utility system impacts and then apply relevant policy goal impacts. Compared to more traditional types of tests, which do not change based on a jurisdiction's priorities, these types of tests are adaptable to encompass the goals of that jurisdiction specifically.

Jurisdiction-specific tests may align with traditional test perspectives but do not necessarily have to. Traditional perspectives are centered on utility system impacts, which represent the utility system perspective. A total resource cost test then layers on impacts such as those related to host customers, other fuels, and water use. A social cost test would then also add social impacts to the evaluation. This type of perspective is particularly helpful for assessing distributed energy resources such as battery storage, which are often the subject of specific policy goals.

Figure 12 illustrates the differences between the regulatory perspective and traditional perspectives.

Figure 12: Developing a jurisdictional-specific societal cost test[xciv]



Based on stakeholder feedback in the RFI and Opportunity for Comment, the criteria established in the Act, and guidance from the NSPM, this analysis utilizes the utility cost test (UCT), which quantifies the expected impact of storage on the utility system and ratepayers, and jurisdictional societal cost test (SCT),[xcv] which quantifies the expected impact on Maine including metrics corresponding to the requirements of the Act, for its assessment of storage. Table 8 lists the benefits and costs included in these two tests.

Table 8: Benefits and costs in Utility Cost Test and Jurisdictional Societal Cost Test

UCT: Perspective of utility / ratepayers	
-Avoided capacity **-Avoided energy and capacity DRIPE (net of charge and discharge)** **-Avoided transmission and distribution (T&D) costs** **-Risk (net of charge and discharge)** **-Reliability**	Program incentive, calculated as the difference between storage costs and market revenues.[6] And: Utility administration costs
Jurisdictional-SCT: Perspective of society / state	
-Avoided energy and capacity DRIPE (net of charge and discharge) **-Avoided transmission and distribution (T&D) costs** **-Risk (net of charge and discharge)** **-Reliability** **-Market revenues (for developers)** [7] **-Greenhouse gas impact (net of charge and discharge)**	Project costs, including the following: • Tax incentives • Developer capital and O&M expenses And: • Utility administration costs

Many, but not all, typical utility-system impacts are included in the UCT assessment. The UCT includes program incentive costs, utility administration costs, avoided energy and capacity costs, avoided energy and capacity DRIPE, avoided transmission and distribution costs, avoided risk, and avoided reliability.[8] The UCT

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

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

[8] Pages 17 and 18 of AESC 2024 state that the reliability analysis addresses the effect of increased reserve margins based on generation reliability, the potential and obstacles in estimating the reliability associated with reduced load levels on T&D, and value of lost load (VoLL). The study also estimates the value of increased generation reliability per kilowatt of peak load reduction. The study applies the VoLL to the calculation of reliability benefits resulting from dynamics in New England's FCM to estimate cleared and uncleared benefits linking to improving generation reliability. The 15-year levelized values are \$0.38 per kW-year for cleared benefits and \$4.82 per kW-year for uncleared benefits.

does not include utility performance incentives, avoided credit and collection costs, avoided renewable portfolio standards costs, and improved resilience.

For the jurisdictional SCT, market revenues for developers are included along with greenhouse gas emissions as contemplated by the Act. The jurisdictional SCT does not include: other environmental impacts such as other air emissions, solid waste, land, water, and other environmental impacts; public health impacts such as health impacts, medical costs, and productivity affected by health; economic and job impacts; energy security impacts; low-income customer impacts; and resilience impacts beyond those experienced by utilities.

Twelve scenarios for standalone storage were modeled, including: 2-hour, 4-hour, and 6-hour storage in two sizes for transmission-connected storage (5 megawatts and 60 megawatts) and two sizes for distribution-connected storage (1 megawatt and 5 megawatts). These sizes are intended to be representative, not to serve as recommended minimum or maximum sizes.

Values, inputs, and assumptions from the AESC 2024 were used to estimate the expected benefits of storage. Capital cost estimates were drawn from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline.[xcvi] It is important to note that the intent of the analysis was to robustly assess cost-effectiveness of storage in Maine as required by the Act, rather than to precisely forecast storage prices and revenues or precisely quantify the necessary incentives, given the recommendation that compensation rates be set through a competitive process.

It is assumed that storage is operational for a 20-year period beginning in 2027. A nominal discount rate of about 4 percent, 1.74 percent real, is assumed for modeling purposes, a default value provided in AESC 2024 that is also reasonably aligned with a societal perspective. Detailed benefit-cost modeling assumptions are provided in Table 9.

Table 9: Benefit-Cost Analysis Inputs and Assumptions

Category	Unit	Value	Transmission-connected?	Distribution-connected?	Notes
Overall BCA assumptions					
Measure life	*Years*	20	X	X	-
Program year	-	2027	X	X	-
Energy losses	*%*	9		X	From AESC 2024.
Peak demand losses	*%*	16		X	From AESC 2024.
Wholesale risk premium	*%*	8	X	X	From AESC 2024. The risk premium is used to convert wholesale prices to retail prices.
Inflation rate	*%*	2.25	X	X	From AESC 2024.
Real discount rate	*%*	1.74	X	X	Calculated using a nominal discount rate of 4.03% and an inflation rate of 2.25%, from AESC 2024.
Cost assumptions					
Administrative costs	*2024$ per yr*	600,000	X	X	Estimated total administrative costs for a 200 MW portfolio.
Incentive costs	*2024$ per kWh*	$74-1,126	X	X	Net present value of incentive calculated by netting out present value of all developer costs and any projected wholesale revenues. See **Error! Reference source not found.** for further detail.
Capital expense	*2024$ per kWh*	$362-826	X	X	NREL's 2023 ATB.
Fixed O&M	*2024$ per kWh-yr*	$9-21	X	X	NREL's 2023 ATB.
Investment Tax Credit (ITC)	*%*	30%	X	X	Inflation Reduction Act clean energy ITC, assuming wage and apprenticeship requirements are satisfied, with no additional adders.
Developer cost of capital	*%*	9.5%	X	X	Calculated assuming a 7% cost of debt and 12% cost of equity and 50/50 debt-equity ratio. Used to inform the developer incentive.
Fixed service charge	*2024 thousand $/yr*	$119-143		X	B-ES Tariff, LGS-P-TOU (See discussion in Section 0)

Demand charges	*2024 $ per kW*	$6-15		X	B-ES Tariff, LGS-P-TOU

Pooled Transmission Facility (PTF)	*2024$ per kW-yr*	Transmission: $69 Distribution: $80	X	X	Full value from AESC 2024, multiplied by discharge at ISO-NE annual peak.
RNS	*2024$ per kW-yr*	$154		X	Full value from AESC 2024, multiplied by discharge at Maine's monthly peak (year 1); after year 1, derated RNS value by 10.87 percent times discharge at monthly peak. This is due to analysis of year 1 RNS under-collection that is socialized and reduces the effect of storage on avoided RNS rates when accounted for in later years.
Avoided capacity costs	*2024$ per kW-yr*	Cleared: $30-102 Uncleared: $0-123	Cleared	Uncleared	From AESC 2024. Uncleared capacity value is multiplied by applicable uncleared scaling factor calculated using AESC 2024's Appendix K.
Capacity DRIPE	*2024$ per kW-yr*	Cleared: $0-211 Uncleared: $0-164	Cleared	Uncleared	From AESC 2024. Uncleared capacity value is multiplied by applicable uncleared scaling factor calculated using AESC 2024's Appendix K.
Avoided distribution costs	*2024$ per kW-yr*	$291		X	From Maine average avoided distribution costs used by Efficiency Maine, multiplied by discharge at Maine
Avoided greenhouse gas costs	*2024$ per short ton*	$178-248	X	X	New England electric sector marginal abatement costs from AESC 2024.
Reliability	*2024$ per kW-yr*	Cleared capacity: $0-15 Uncleared capacity: $0-$32	Cleared	Uncleared	From AESC 2024, quantifies additions to system reliability. Does not consider location-specific reliability benefits.

Electric DRIPE	*2024$ per MWh*	$1-9	X	X	Seasonal peak and off-peak values taken from AESC 2024 and applied to modeled charging profiles. Electric DRIPE effects due to discharging and charging are netted out.
Wholesale market revenues	*2024 $ per kW-yr*	$32-129	X		Include energy arbitrage, reserves, RT premium, scarcity adders, capacity and PFP payments. Described further in Section **Error! Reference source not found.**.

Program Incentives

To model the necessary costs to enable storage development, an upfront incentive is estimated that is equal to the difference between storage costs and revenues, assuming a developer's cost of capital of 10 percent.[9] **Error! Reference source not found.**Table 10 shows the modeled net present value of the incentives. For modeling purposes it was assumed that incentive costs (i.e. payments) are incurred up front. However, in actuality it is anticipated that at least 50 to 70 percent of performance incentives be paid for dispatch during critical hours (i.e. through performance payments). As indicated in the table, incentives are assumed to be energy based ($/kWh) and vary depending on the capacity in both energy and power terms. For example, based on an analysis of the difference between costs and revenues described above, a 60 MW / 120 MWh battery is anticipated to require a $100 per MWh incentive, or around $12,000, if paid all up-front.

Under the UCT, the modeled incentive is explicitly counted as a cost. From the utility system's perspective, the cost of the project is simply the cost of the incentive. Since the full project costs and wholesale revenues flow through the developer, they do not appear in either the benefits or the costs from the utility system's perspective. This differs from the jurisdictional SCT, where the incentive is a transfer payment between two parties that are both within the scope of the jurisdiction. Therefore, the incentive does not appear as an explicit cost under the jurisdictional SCT. In this test, the full project costs and wholesale revenues are accounted for directly in the costs and benefits, respectively.

Table 10: Modeled Incentive Values

2024$/kWh	2 Hour	4 Hour	6 Hour
Transmission-connected			
60 MW	$100	$74	$80
5 MW	$214	$116	$99
Distribution-connected			
5 MW	$562	$380	$310
1 MW	$1,126	$648	$479

[9] Calculated assuming a 7% cost of debt and 12% cost of equity and 50/50 debt-equity ratio. A cost of capital at approximately this level assumes that project capital stacks include some debt; securing such debt would likely be contingent upon the availability of incentives that reduce the project's exposure to wholesale market price volatility.

Actual incentive levels should be determined and administered by the program administrator, ideally through a competitive procurement in which projects bid desired incentive levels and are selected in part on a least-cost basis.

Cost-Effectiveness Results

Overall, the cost-effectiveness modeling indicates systems with larger capacities tend to have greater benefit-cost ratios than systems with smaller capacities. This is primarily due to economies of scale in project costs, whereby larger storage systems have lower capital expenses on a unit-cost basis than smaller installations, while at the same time most of the benefits scale proportionally with the size of the system. There is not a monotonic relationship between project duration and cost effectiveness. Different values scale differently with changes in duration. For example, energy arbitrage opportunities have diminishing returns to increased duration, while capacity-denominated values scale proportionally.

Transmission-connected Storage Results

As described above, it is assumed that transmission-connected storage would participate in wholesale capacity, energy, and reserves markets. Modeled dispatch was based on responding to performance calls during critical hours, and otherwise assumed to optimize wholesale market revenues. Figure 13 and Figure 14 display the benefit-cost ratios results for all modeled transmission-connected storage systems under the UCT and SCT respectively. For transmission-connected storage, all combinations of durations and capacities were cost-effective under both tests.

The UCT base case results are generally higher than the jurisdictional SCT results for both transmission and distribution connected storage. The jurisdictional SCT has greater costs than the UCT since it includes the full project costs (developer project costs), as opposed to just the program incentive, and two of many potential societal benefits. While the jurisdictional SCT sees incrementally greater benefits than the UCT due to the inclusion of wholesale market revenues (developer revenues; including capacity, energy, and ancillary services) and greenhouse gas reduction benefits, the increase in costs is greater than the increase in modeled benefits, causing the benefit-cost ratio to be lower.

Figure 13: Utility Cost Test for Transmission-connected storage: Benefit-Cost ratios

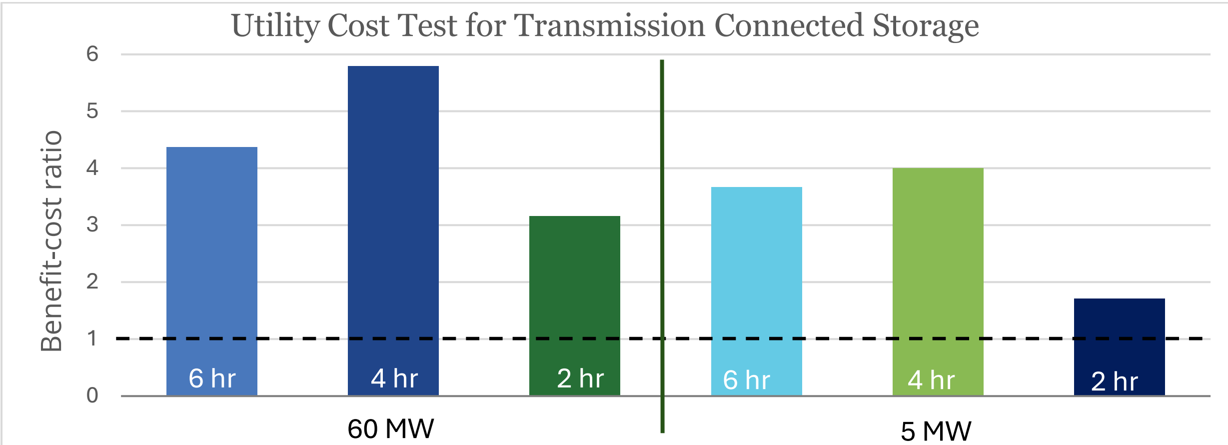
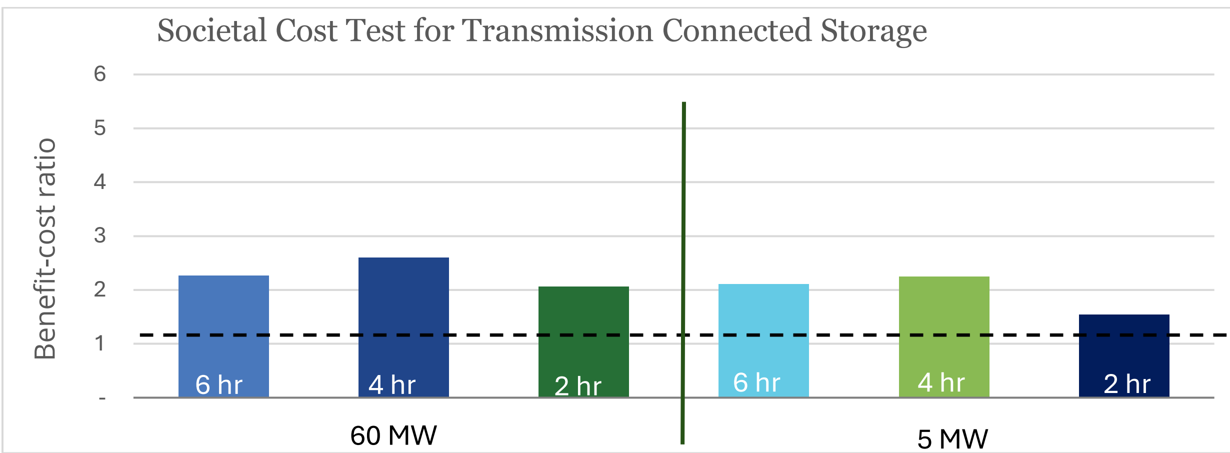


Figure 14: Societal Cost Test for Transmission-connected Storage: Benefit-Cost ratios



Distribution-connected Storage Results

The analysis demonstrates that procurement of distribution-connected storage through a competitive solicitation framework may be beneficial to ratepayers if distribution benefits (in the form of avoided or deferred utility infrastructure costs) are realized. For distribution-connected storage, all combinations of capacities and durations were cost-effective under the UCT. For base case analyses, distribution-connected projects are load reducers that do not participate in wholesale markets. The modeling optimized distribution-connected storage to defer or avoid distribution peaks in the winter while, in other seasons, storage was used to reduce RNS charges.

The modeling found that 1 megawatt and 5 megawatt energy storage systems with durations of 2, 4, or 6 hours met the UCT and SCT, as all combinations of capacities and durations were cost-effective, and all systems were cost-effective except for 1 megawatt capacity and 2-hour duration systems. Under the SCT, 1 megawatt capacity and 2-hour duration systems were not likely to be cost-effective. Figure 15 and Figure 16 summarize these results, respectively. Avoided RNS and avoided distribution costs are the primary drivers of benefits for this use case.

Figure 15: Utility Cost Test for Distribution-connected storage: Benefit-Cost ratios

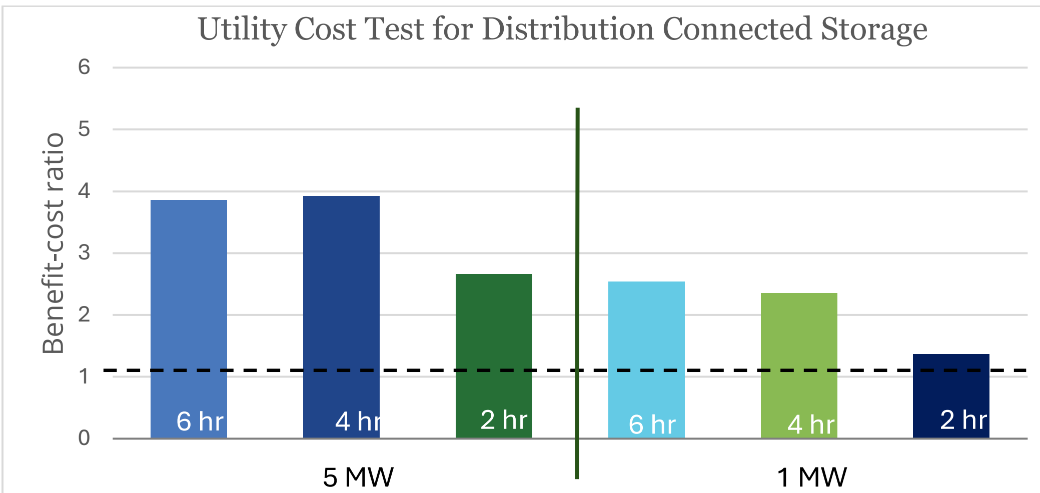
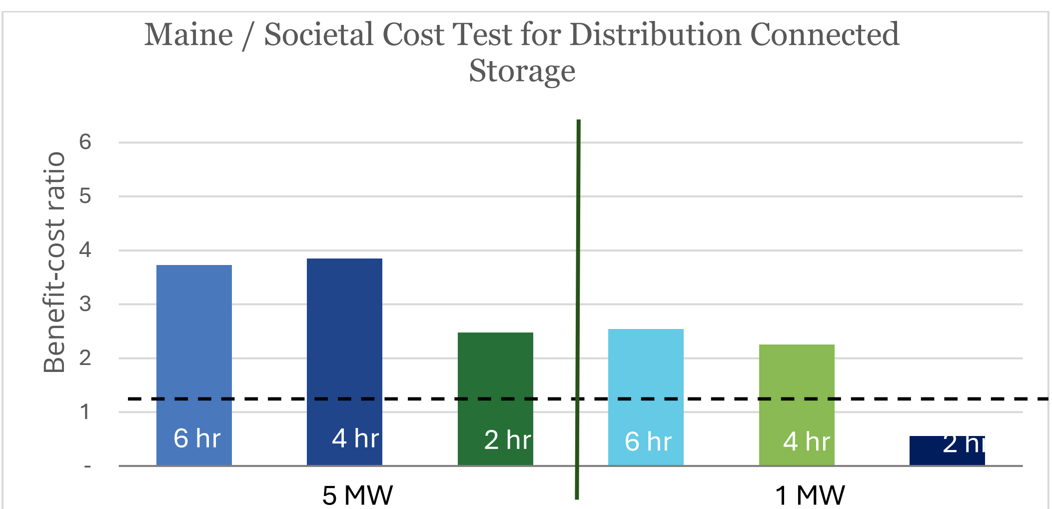


Figure 16: Societal Cost Test for Distribution-connected storage: Benefit-Cost ratios



Of the potential values considered, most were compatible with the preferred procurement mechanism, namely a pay-for-performance mechanism that includes an upfront incentive. However, avoided distribution system costs, which represent the single largest potential benefit stream, may not be achievable exclusively through the use of a pay-for-performance mechanism, as discussed above.

Ratepayer Impact Analysis

Estimated rate and bill impacts were calculated based on an assumed procurement resulting in the following resources:

- Two 60 megawatt 6-hour transmission-connected batteries;
- Eight 5 megawatt 6-hour transmission-connected batteries;
- Eight 5 megawatt 6-hour distribution connected batteries.

Utilizing the modeling inputs and results described above and isolating only those costs and benefits that impact utility rates, estimated rate impacts for residential customers in Versant and CMP service territories and small commercial customers in CMP's service territory were calculated. Net benefits and costs of the storage program are assumed to be shared proportionally among customer classes based on energy consumption. Thus, the per kilowatt-hour rate impacts are the same between each of the three modeled customer classes.

Based on the assumed bid incentive values calculated in Table 10, it is assumed that customers would be subject to a rate increase of $0.0096/kWh in the first program year due to the modeled developer incentive provided in this year; every year thereafter would exhibit a rate decrease, beginning in program year two at $0.0054/kWh. Over the first ten years of the program, customers would save an average of $0.00237/kWh.

For an average CMP residential customer, these rate impacts translate to an average monthly bill increase of $5.90 per month in year one and bill decreases thereafter starting at $3.41 per month in year two. Over the first ten years of the program, CMP residential customers would experience bill reductions of $1.77 per month, on average.

For an average Versant residential customer, the rate impacts translate to an average monthly bill increase of $4.89 per month in year one and bill decreases thereafter starting at $2.83 per month beginning in year two. Over the first ten years of the program, modeled Versant residential customers would experience bill reductions of $1.50 per month, on average.

For an average CMP small general service customer, the rate impacts translate to an average monthly bill increase of $9.20 per month in year one and bill decreases thereafter starting at $5.30 per month in year two. Over the first ten years of the program, CMP Small General Service customers would experience bill reductions of $2.73 per month, on average.

It is important to note that these estimates are based on the ratio between upfront incentive and pay-for-performance incentives; with lower up-front incentives, there could be smaller initial customer impact, with correspondingly lower savings in later years.

Energy Storage Program Recommendations

The Act requires that the Commission "review the recommendations of [this] report and determine whether the program recommended by the [GEO] is reasonably likely to achieve the objectives [of the Act]. Upon finding the proposed program reasonably likely to achieve the objectives [of the Act], the Public Utilities Commission shall take steps to implement the program in accordance with any applicable authority the commission may have under law."[xcvii]

Based on the substantial stakeholder input provided in response to the RFI and the Opportunity for Comment, as well as the technical analysis described above, the GEO concludes that an energy storage procurement program consistent with the following recommendations is reasonably likely to be cost-effective for ratepayers and to advance the objectives of the Act. Accordingly, the GEO recommends the Commission:

- Find a program as described below to be reasonably likely to meet the objectives of the Act, and
- Take steps to implement the program in accordance with any applicable authority the Commission may have under law, and
- To the extent the Commission determines it lacks sufficient authority under existing law, take expedient steps, in collaboration with the GEO, to submit to the Joint Standing Committee on Energy, Utilities and Technology of the 132nd Maine Legislature recommendations for any changes to law needed to allow the commission to fully implement the program.

Program Priorities

- Cost-effectiveness: Target reduction in transmission costs for Maine ratepayers by incentivizing dispatch during peak periods. Minimize necessary

incentives by maximizing the ability for bidding projects to participate in wholesale markets.
- Advancement of storage deployment: Adopt simple, administratively streamlined program design to maximize participation and competition.
- Commercial availability: Require bidders to address the commercial availability of their proposed technology. Provide flexibility in this requirement by accepting (1) demonstration of commercial deployment in other jurisdictions, (2) demonstration of successful pre-commercial deployment indicating commercial readiness, (3) reference to an accepted commercial readiness designation such as a U.S. Department of Energy Technology Readiness Level designation.

Allocation of Capacity

- Transmission-connected resources: Conduct one or more tranches of competitive procurement for up to 160 megawatts of transmission-connected energy storage projects.
- Distribution-connected resources: Initiate an investigation to determine areas of the distribution system where deployment of energy storage to manage winter peaks and defer alternative investments, and/or increase winter resiliency, is most likely. Following such an investigation, conduct one or more tranches of competitive procurement for up to 40 megawatts of distribution-connected energy storage projects.
- Multiple solicitations may be warranted to maximize deployed capacity in line with the Act in the case of project attrition.

Solicitation and Incentive Structure

- Federal incentives: While a competitive solicitation will presumably incentivize bidders to pursue tax credits to ensure price competitiveness, the solicitation should require bidders to indicate what tax credits they anticipate receiving as part of the bidding process.

Program Administration

- Consider whether dispatch should be based on a third-party signal, or based on the storage operator’s discretion.

Statutory Authority

- Examine the applicability of authority established under 35-A M.R.S. §3210-C and 35-A M.R.S. §3210-G to implement the program recommendations.

- Examine alternative potential authority consistent with the Act's directive to utilize "any applicable authority the commission may have under law."

Additional Considerations

- Decommissioning: Require bidders to demonstrate compliance with Maine's decommissioning law, including plans or commitments to plan for recycling and proper disposal in accordance with applicable standards.
- Safety: Require bides to demonstrate commercially reasonable efforts and compliance with applicable federal and state standards regarding safety, including but not limited to fire safety.
- Community engagement: Require bidders to demonstrate a stated commitment to abide by and support municipal emergency preparedness and public safety needs, and to engage host communities in the development and siting of energy storage projects.

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