Benefit Cost Analysis of FTM Distribution Connected Storage

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AUGUST 4, 2026



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I. Executive Summary

The study evaluated the use of front-of-the-meter (FTM) distribution-connected battery energy storage systems (BESS) to address targeted distribution system needs while reducing net customer costs through participation in wholesale electricity markets and the Massachusetts Clean Peak Standard (CPS). The analysis examined two primary BESS use cases: (1) distribution capacity in a constrained area and (2) reliability improvement in an outage-prone area. The study also evaluated the extent to which revenues from ISO New England (ISO-NE) wholesale markets and the CPS could offset storage costs to ratepayers.

The study found that a BESS asset can successfully serve distribution capacity and reliability needs based on two selected sample locations with distribution system needs in National Grid's service territory. In the distribution capacity example, a BESS asset would be able to cost-effectively defer the forecasted distribution feeder capacity constraint by seven years. In the reliability improvement use case, the BESS asset would be able to serve load during 99.5% of outage periods if they continue to follow the historical patterns observed in the modeled location. In both example use cases, the study shows that co-optimizing battery operation for wholesale market and CPS participation could reduce the net present value (NPV) utility revenue requirement for the BESS asset, while maintaining sufficient capacity to serve the distribution use case. Co-optimized market and CPS participation reduces the BESS cost to ratepayers by up to 76% in the capacity example and 62% in the reliability example.

This report is organized into an Executive Summary and a Technical Appendix. The Executive Summary presents the key findings from the two modeled distribution storage use cases, including BESS costs, revenues, and net benefits. The Technical Appendix provides detail on the underlying assumptions, modeled distribution needs, market price and program inputs, and battery dispatch methodology used to develop these findings.

A. Distribution Capacity Use Case

The first use case focuses on the operation of a distribution-connected battery to defer a capacity upgrade on a constrained distribution feeder in northeastern Massachusetts. The modeled feeder has a summer rating of 12.4 MW and experienced peak loading of 10.9 MW in 2025 – approximately 88% of its rating. National Grid load forecasts project that peak loading

on the feeder will grow at 4.7% per year through 2042. Absent the battery, National Grid plans to upgrade the feeder by 2028 to maintain loading within operating limits.

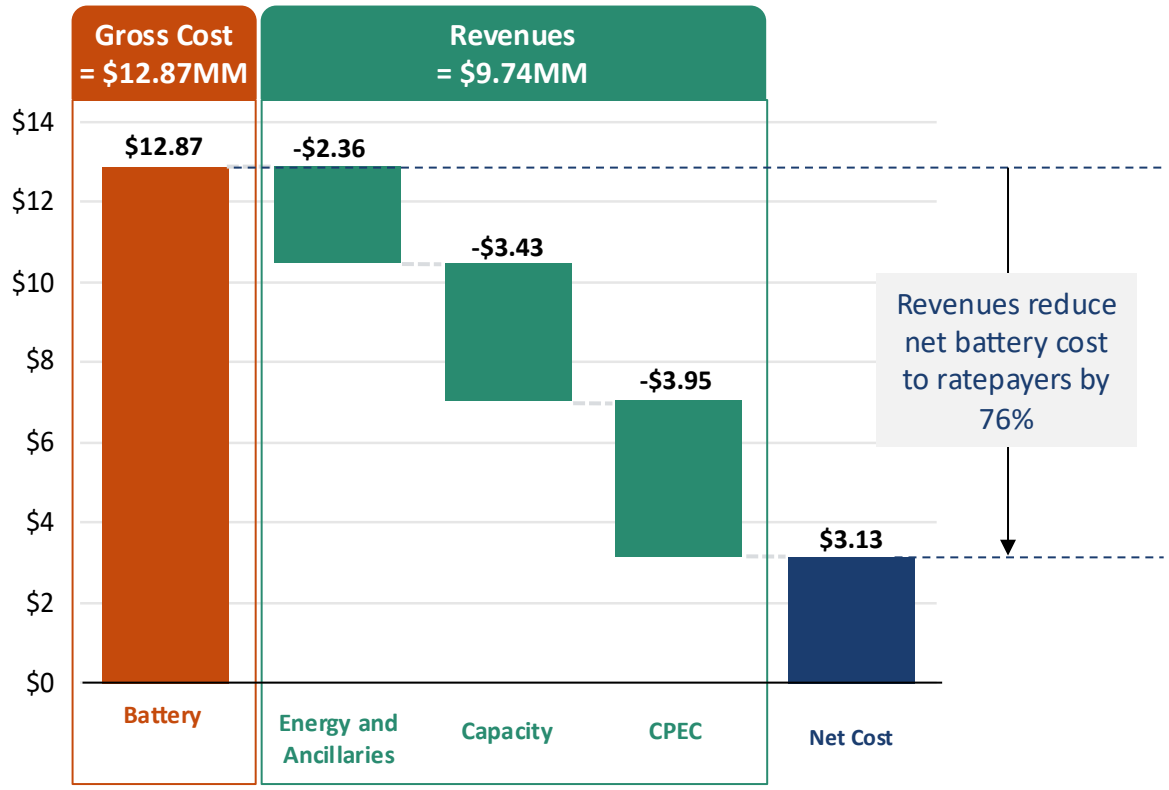
The study evaluated deployment of a 3.15 MW, eight-hour battery designed to maintain feeder loading at or below the National Grid distribution planning threshold of 75% of the line's rated capacity. Forecasts of hourly feeder loading were used to identify the capacity needs that the battery would be dispatched to serve. Under these assumptions, the modeled battery is able to sufficiently shave peak load and keep the feeder below the planning threshold through the end of 2034. The analysis found that extending the deferral period into 2035 would likely require a significantly larger and longer-duration storage system, which is not typical for non-wires solutions at this time and is unlikely to be cost-effective.

The modeled operational strategy is designed such that meeting the distribution system need would be the battery's primary use case. During hours in which feeder loading is forecasted to exceed the planning threshold, the battery discharges to reduce loading on the constrained asset. In periods without feeder capacity needs, the battery participates in wholesale energy, ancillary services, capacity markets, and the CPS program. Because the feeder requires battery dispatch during a limited number of hours annually, the battery remains available for market participation during most operating intervals. There is a small revenue trade-off associated with co-optimizing the battery for both distribution and wholesale market purposes, relative to a battery used only in the wholesale market.[1] The study used historical hourly feeder loading data and ISO-NE market prices from 2021 through 2025 to characterize the wholesale market trade-offs associated with dispatching the battery for the feeder capacity need.

Figure 1 shows the net cost of the battery to ratepayers after accounting for modeled wholesale market and CPS revenues. The 15-year NPV of gross revenue requirement to own and operate the battery is estimated at $12.87 million. Based on forecasted ISO-NE market prices and clean energy peak certificate (CPEC) prices and modeled battery optimization of these revenues, the 15-year NPV of revenues is estimated at $9.74 million. This results in a net revenue requirement of $3.13 million, a 76% reduction relative to the gross cost. The net battery cost result is sensitive to the assumed battery capital cost and forecasted market prices. Sensitivity analysis shows that if capacity prices are 30% lower than modeled, net cost would be $4.16 million, and if battery capital cost is 35% higher, net cost would be $7.36 million.

[1] Under the modeled assumptions, prioritizing the distribution capacity need reduced market revenues by 0.2% relative to a market-only dispatch strategy.

FIGURE 1 BATTERY GROSS COST, REVENUES, AND NET COST TO RATEPAYERS

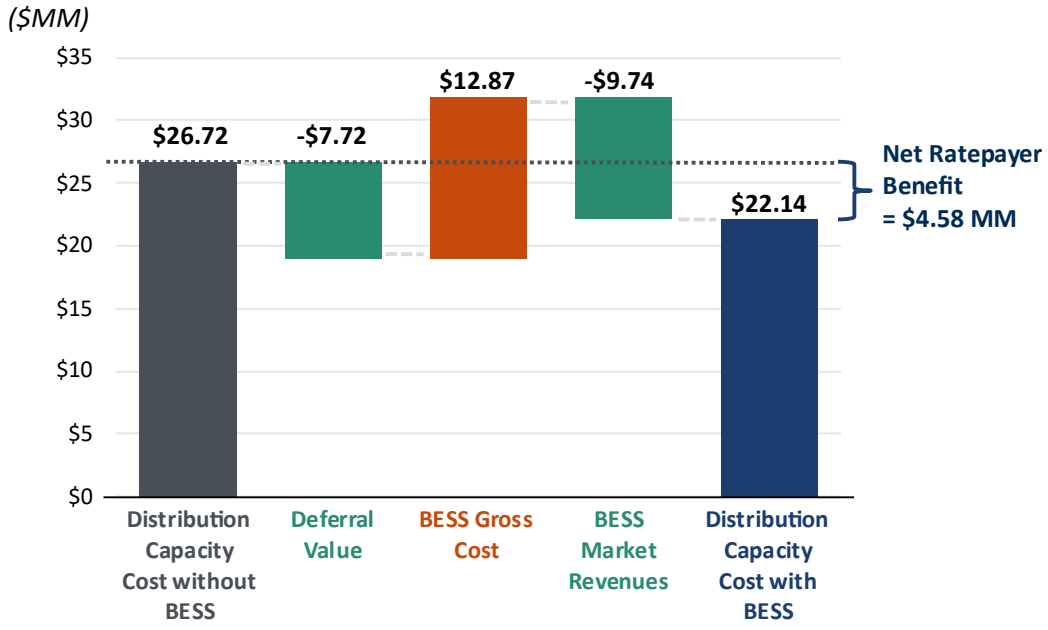


Note: Gross battery cost refers to revenue requirements over the 15-year asset lifetime, including depreciation, O&M, return on rate base, and interconnection costs. NPVs are shown in 2027$.

Figure 2 shows the cost-effectiveness of utilizing the modeled battery for distribution capacity at the constrained feeder in northeastern Massachusetts. The battery is cost-effective as an alternative to the traditional wires solution that is likely to be planned for this location. Under the counterfactual case without storage, the conventional upgrade was estimated to require approximately $14 million in capital investment, resulting in an estimated NPV revenue requirement of approximately $26.7 million[2]. Under the storage case, the feeder upgrade is deferred by seven years, and this reduces the NPV revenue requirement of the traditional solution by $7.72 million. As discussed above, the net cost of the battery after market revenues is estimated at $3.13 million. Therefore, the BESS is a cost-effective solution for the distribution capacity use case. The study estimated an overall net benefit of $4.58 million and a benefit-cost ratio of approximately 1.4 for the storage solution relative to the traditional wires alternative.

[2] This revenue requirement includes costs of perpetually replacing the new asset at the end of its useful lifetime. When the upgrade is deferred, the perpetual replacements are also deferred by the same number of years.

FIGURE 2. COSTS AND BENEFITS IN THE DISTRIBUTION CAPACITY USE CASE



Note: NPVs are shown in 2027$.

It is important to note that National Grid pursuing the revenue opportunities for the BESS asset is crucial for the cost-effectiveness of the distribution capacity BESS use case. Without those revenues, the cost of the battery plus the deferred wires investment in 2035 would be higher than simply building the wires solution in 2028.

The analysis evaluated operational interactions between the distribution capacity need and market participation and found that it is possible to co-optimize these opportunities with limited trade-offs between the two objectives. This is possible because the periods of highest loading at this example feeder generally coincide with periods of elevated energy market value, historical ISO-NE Capacity Scarcity Conditions (CSCs), and the evening peak periods associated with CPEC production opportunities. To capture these opportunities, National Grid will need to develop sophisticated operational forecasting, dispatch, and planning capabilities along with having dedicated utility staff to ensure accurate visibility into operations and to maintain reliability.

B. Reliability Improvement Use Case

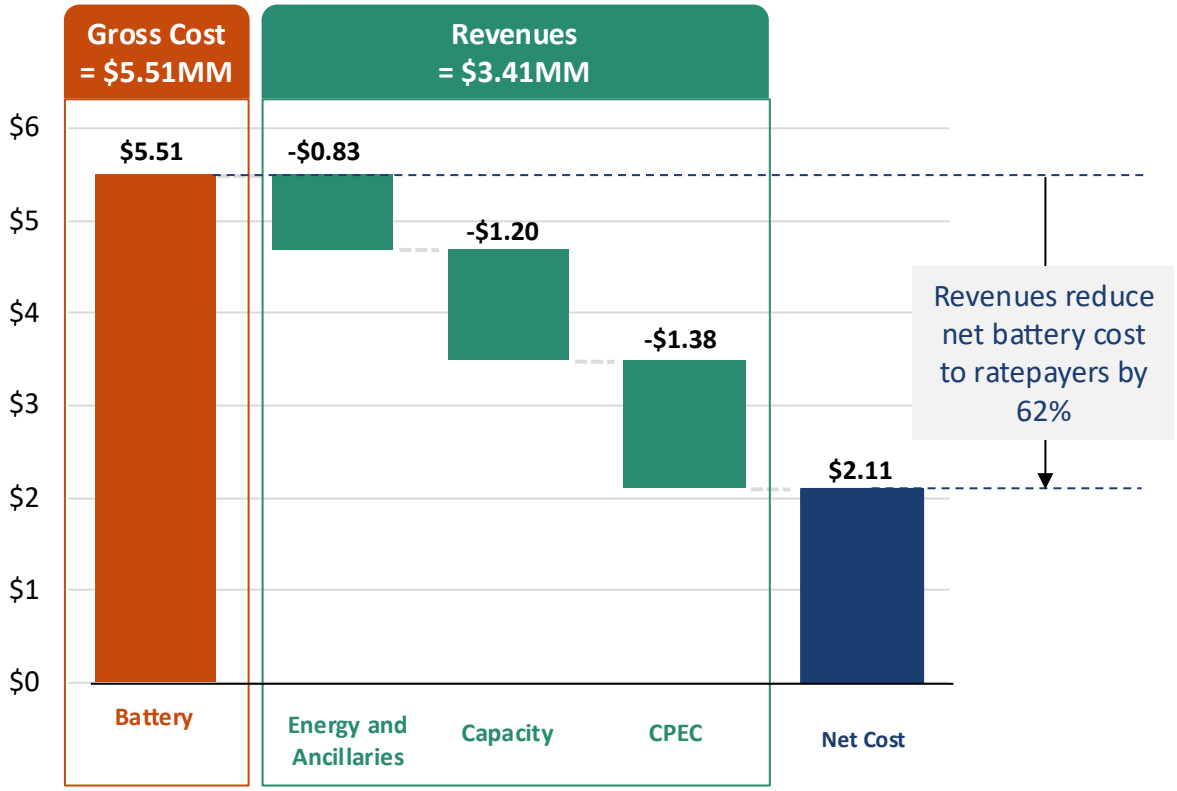
The second use case focuses on the operation of a distribution-connected battery to improve reliability for an outage-prone underground residential development (“URD”) in central

Massachusetts. Historical outage data from 2021 through 2025 showed that the URD experienced 24 outage events with an average outage duration of approximately 196 minutes. The feeder serving this URD experiences weather-, vegetation-, and equipment-related outages that result in customer interruptions.

The study evaluated deployment of a 1.1 MW, eight-hour BESS sized to the URD's peak load, with the BESS operating in islanded mode during outages to serve customer load. Historical outage patterns and representative residential load profiles were used to evaluate the battery's ability to serve load during outages. The analysis considered two operational strategies: (1) a reliability-only strategy under which the battery is reserved exclusively for outage mitigation and (2) a market participation strategy under which the battery participates in wholesale markets and the CPS program and serves the URD to the extent possible during outage periods.

The analysis shows that based on historical outage patterns, the battery would be capable of reducing outages by 99.5% under the market participation strategy. The study estimated that wholesale market participation and CPS revenues would offset $3.41 million of the battery's $5.51 million revenue requirement over the 15-year life of the asset. The resulting NPV net revenue requirement is $2.11 million, representing a 62% reduction relative to the battery's gross cost, as shown in Figure 3.

FIGURE 3. COSTS AND REVENUES IN THE RELIABILITY USE CASE



Note: Gross battery cost refers to revenue requirements over the 15-year asset lifetime, including depreciation, O&M, return on rate base, and interconnection costs including reclosers. NPVs are shown in 2027$.

A traditional reliability improvement solution for this location would likely involve a Fault Location, Isolation, and Service Restoration (FLISR) scheme and targeted undergrounding of certain sections of the feeder at a total cost of $24.3 million in capital investment. National Grid estimates that this solution would address about 80% of the outages faced by the URD. Because of the high cost of the traditional solution, the solution is unlikely to be pursued, and the appropriate counterfactual would be continued customer exposure to outages, absent deployment of storage. Therefore, this report presents the reliability case results in terms of the net cost of achieving the reliability improvement, rather than as a benefit-cost analysis.

The analysis also evaluated the interaction between outage-related BESS operation and market participation. As the battery is modeled as optimizing for market revenues, there is a risk that it has insufficient state of charge to serve the URD in case of an unexpected outage. The study assessed this risk by modeling how many of the historical outages this battery could have mitigated if it were also optimizing for revenues during those historical years. The modeling showed that insufficient battery state of charge would have occurred during less than 0.5% of

outage intervals. Therefore, the battery could provide significant reliability improvement to the URD, while participating in the market to reduce the net cost to ratepayers.

C. Value Stacking Considerations

A central component of the analysis involved evaluating the extent to which battery costs could be offset through participation in wholesale electricity markets and state clean energy programs. The study modeled four primary value streams: wholesale energy price arbitrage, ancillary services, capacity market participation, and Massachusetts Clean Peak Standard revenues.

Energy market revenues were modeled based on hourly wholesale price forecasts derived from the 2024 National Laboratory of the Rockies (NLR) Cambium dataset.[3] Under the modeled strategy, the battery charges during lower-priced hours and discharges during higher-priced periods to capture arbitrage value. Ancillary services revenues were modeled using historical regulation and spinning reserve market data and represented as a net revenue premium above energy market revenues.

The study also modeled participation in the ISO-NE Forward Capacity Market (FCM). Capacity revenues were based on projected market clearing prices and battery accreditation assumptions consistent with ISO-NE market rules. The analysis additionally incorporated estimated Capacity Scarcity Condition (CSC) bonus or penalty payments based on modeling of how the battery would have performed if it was in operation during historical CSC events occurring between 2021 and 2025.

Another significant component of the modeled revenue stack was participation in the Massachusetts Clean Peak Standard. Under the CPS program, batteries can generate CPECs by charging during designated renewable generation windows and discharging during predefined seasonal peak periods. The study assumed declining CPEC prices over time but still projected CPS participation to represent one of the largest individual revenue streams available to battery systems over the next fifteen years.

Across both distribution use cases, the analysis found that the timing of distribution system needs generally aligned with periods of elevated market value. Evening peak periods associated

[3] See NLR, Energy Systems Analysis: Cambium, 2024.

with feeder loading, CPS peak windows, and historical scarcity conditions frequently overlapped, limiting the operational trade-off between serving distribution needs and participating in markets. As a result, the modeled storage systems were able to satisfy distribution objectives while still capturing a substantial portion of available market revenues.

Successful implementation of co-optimized dispatch of distribution-connected storage requires sophisticated operational control, forecasting, and planning capabilities, and dedicated utility staff to manage such operations. Real-world considerations such as price and load forecasting accuracy may lead to higher revenue trade-offs than captured in this analysis. Development of new regulatory and incentive frameworks may be merited to ensure that market revenues are appropriately captured to create customer benefits. This could be through mechanisms such as revenue-sharing or benefit-sharing arrangements.

II. Technical Appendix

[Attached]

Benefit Cost Analysis of FTM Distribution Connected Storage

TECHNICAL APPENDIX

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Introduction

Purpose of the Study

National Grid is planning to utilize front of the meter distribution-connected battery energy storage to address distribution system needs. This study evaluates the cost-effectiveness of using storage for the following use cases:

- **Storage as capacity:** By shaving peak demand on connected distribution system assets, storage can effectively serve as additional distribution capacity, allowing additional load growth to be served before grid assets must be upgraded.
- **Storage for reliability:** By serving islanded customers during grid outage events, storage can improve service reliability for connected customers

To reduce the net cost of the battery to ratepayers, National Grid plans to co-optimize battery operation to earn revenues from wholesale markets and state programs. This study models potential battery revenues from "stacking" the following value streams on top of the distribution use case:

- Clean Peak Energy Certificates (CPECs) from MA Clean Peak Standard
- ISO-NE capacity market participation
- ISO-NE energy market participation
- ISO-NE ancillary services market participation

The use of distribution-connected utility-owned storage to address network needs has been gaining traction across the U.S.

- Recent filings in Maryland, Virginia, and Minnesota are progressing to the implementation stages with regulator approvals[1]

[1] Maryland Next Generation Energy Act, Xcel MN Capacity*Connect Program, and Blue Ridge Power Agency plans.

Massachusetts Electric Company and Nantucket Electric Company
each d/b/a National Grid
D.P.U. 26-106
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Description of Modeled Use Cases

We assessed the cost-effectiveness of each distribution use case by modeling storage system costs and the extent to which they can be offset through value stacking of other available revenue sources.

National Grid proposes to deploy FTM storage in select locations with one of these ***distribution grid needs****…*

Use Case 1: Capacity	Use Case 2: Reliability
Battery is operated to shave a distribution asset's peak load and keep it below the 75% planned load limit threshold	Battery is connected to an area with high outage rates and is operated to serve customer load during outages

…and reduce the cost of the battery to ratepayers by co-optimizing for one or more of these ***revenue opportunities***

Clean Peak Standard	Capacity Market	Energy Market	Ancillary Services
Pursue CPEC payments by charging and discharging within the windows eligible for credits	Bid into capacity markets and operate the battery while managing the risk of non-performance penalties during scarcity events	Bid into energy markets to arbitrage against day-ahead and real-time prices on a daily basis	Bid into the regulation and spinning reserves markets

Data Used to Illustrate Distribution Grid Use Cases

To provide a realistic representation of potential distribution grid needs, we used historical data from two candidate locations for these use cases. While these represent plausible locations for storage siting, they are not necessarily the specific locations National Grid will propose for implementation.

Distribution Capacity Use Case

- The battery was modeled as **expanding the capacity of a 12.4 MW distribution line** serving northeastern Massachusetts
- As of 2025, the line experienced peak load of **10.9 MW (88% loaded)** and is forecast to have peak **load growth of 4.7% per year** through 2042
- Without a battery, the **line would require an upgrade by 2028**
- Based on the load shape and load growth on the line, we right-sized a **3.15 MW, 8-hour battery to defer the need until 2035**
- The battery's modeled objective is to **keep the line loading at or below 75%** of its loading limit (the planning threshold)
- To understand the trade-offs between keeping the line load below 75% and co-optimizing for market revenues, we used **historical line loading data from 2021-2025** to represent the load shape and scaled up based on the peak load forecast in 2034

Distribution Reliability Use Case

- The battery was modeled as **serving an underground residential development (URD)** in central Massachusetts during outage events
- **Between 2021 and 2025, the URD experienced 24 outages**, with an **average outage duration of 196 minutes**
- A traditional grid solution for reliability improvement would likely be to underground the feeder serving this location. This would be an expensive solution and is unlikely to be implemented.
- This study evaluates the extent to which an **8-hour battery sized to the peak load of the URD (1.1 MW)** would be able to reduce outages, while optimizing for market revenues
- We use **historical outage data and market prices** to represent any potential correlation between the two and to provide a realistic view of how much unserved energy can be reduced by a battery that is also participating in markets

Distribution Capacity Use Case: Benefits and Costs

The battery is cost-effective for the studied distribution capacity use case, with net benefit of $4.58 MM and BCA ratio of 1.4.

Counterfactual Case:

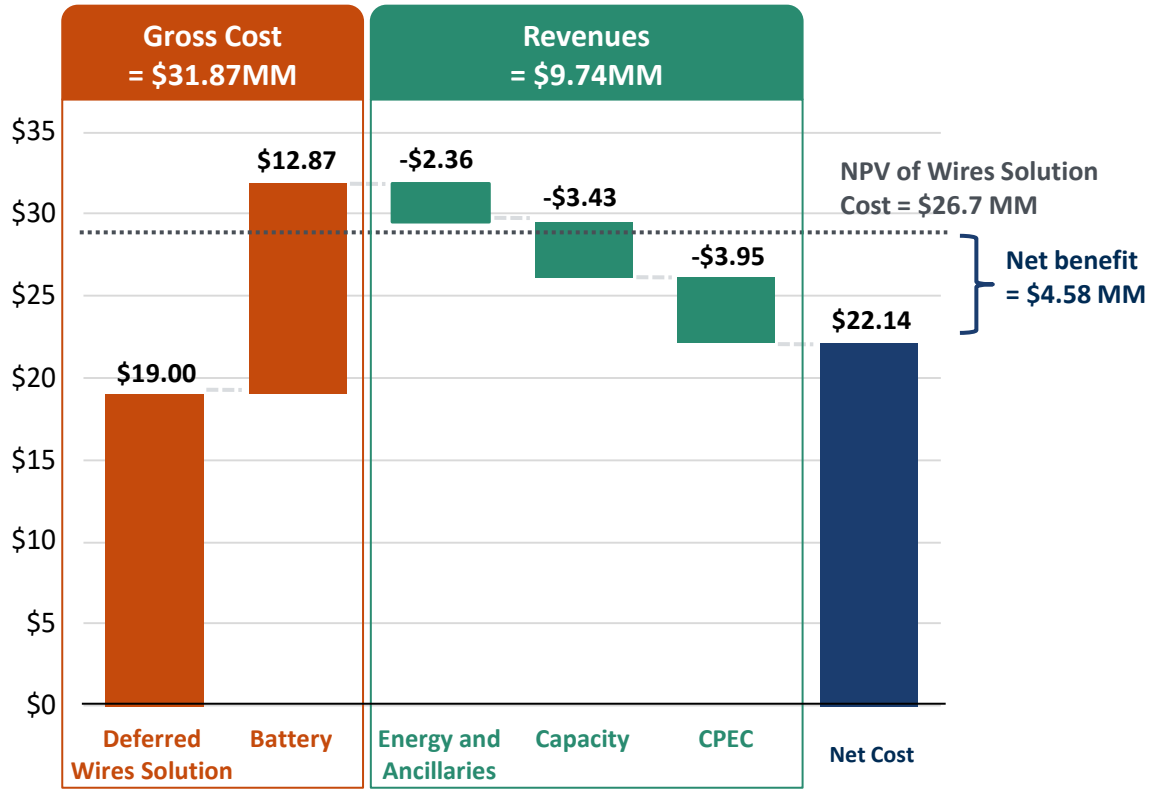
Without the battery, the **wires solution would require a $14.0 MM grid investment in 2028, leading to $26.7 MM in NPV revenue requirement** over the lifetime of the need[1]

Battery Case:

- Based on the load shape on this line, battery operation is able to keep the line below the planned load limit until 2035, **deferring the upgrade by 7 years**
  - This **reduces the NPV of wires solution revenue requirement to $19.0 MM**
- Fully co-optimized market participation revenues can offset the cost of the battery by generating **$9.7 MM in revenues** over its lifetime
  - These revenues **reduce the NPV of battery revenue requirement by 76%** (see next page) and are **crucial for making the battery a cost-effective solution** for the distribution grid need

COSTS AND BENEFITS IN THE DISTRIBUTION CAPACITY USE CASE

NPV IN 2027$ MILLIONS



Note: Battery cost refers to all revenue requirements, including depreciation, O&M, return on rate base, and interconnection costs.

[1] To cover the lifetime of the need, the NPV includes the cost of replacing the wires asset at the end of its useful life (perpetual replacement).

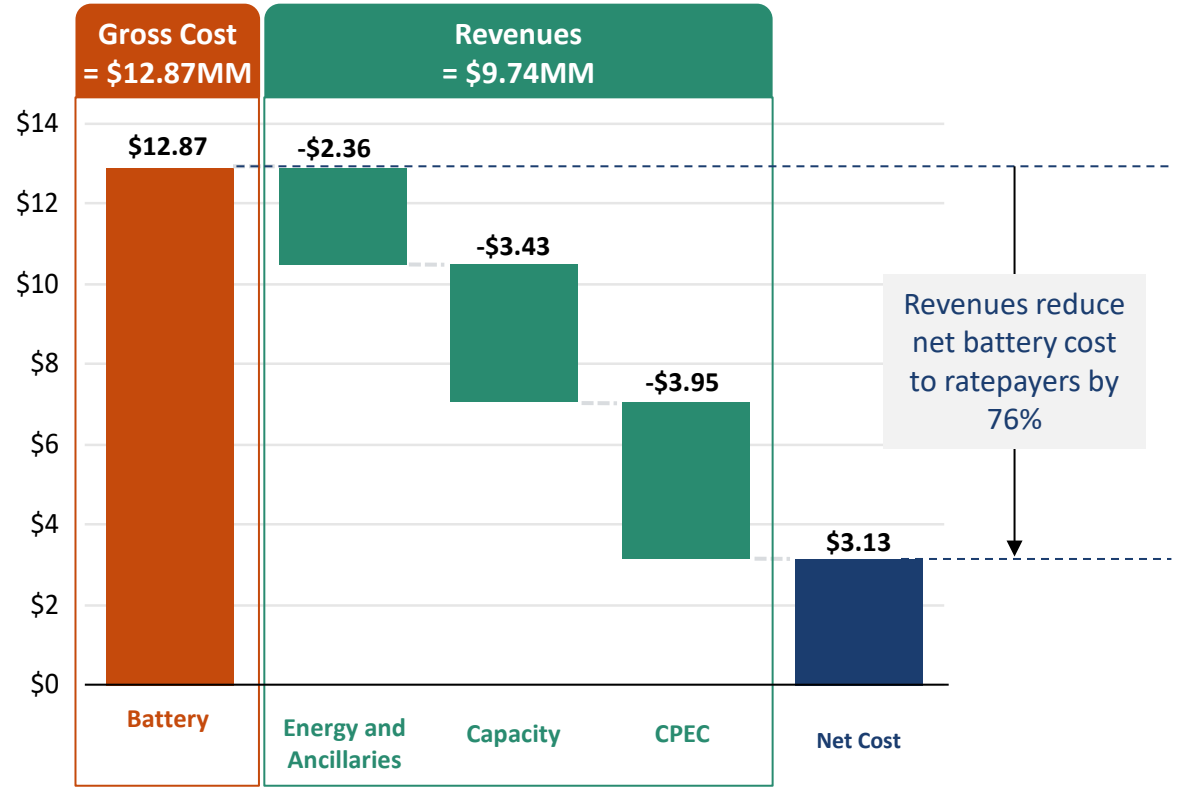
Distribution Capacity Use Case: Battery Net Cost

Participation in wholesale markets and the CPS program would reduce the net battery cost by 76%, from $12.87 MM to $3.13 MM over the 15-year battery lifetime.

- Capturing the opportunities to offset battery costs allows the battery can be a cheaper solution for the distribution capacity need.
- The net battery cost is sensitive to the assumed battery capital cost and forecasted market prices. Sensitivity analysis shows that if capacity prices are 30% lower than modeled, net cost would be $4.2 MM, and if battery capital cost is 35% higher, net cost would be $7.4 MM.

NET BATTERY COST IN THE DISTRIBUTION CAPACITY USE CASE

NPV IN 2027$ MILLIONS



Note: Battery cost refers to all revenue requirements, including depreciation, O&M, return on rate base, and interconnection costs.

Distribution Reliability Use Case: Benefits and Costs

The battery would be able to reduce outages in the modeled location by over 99% at a net cost of $2.11MM NPV over the 15-year battery lifetime.

Battery Case:

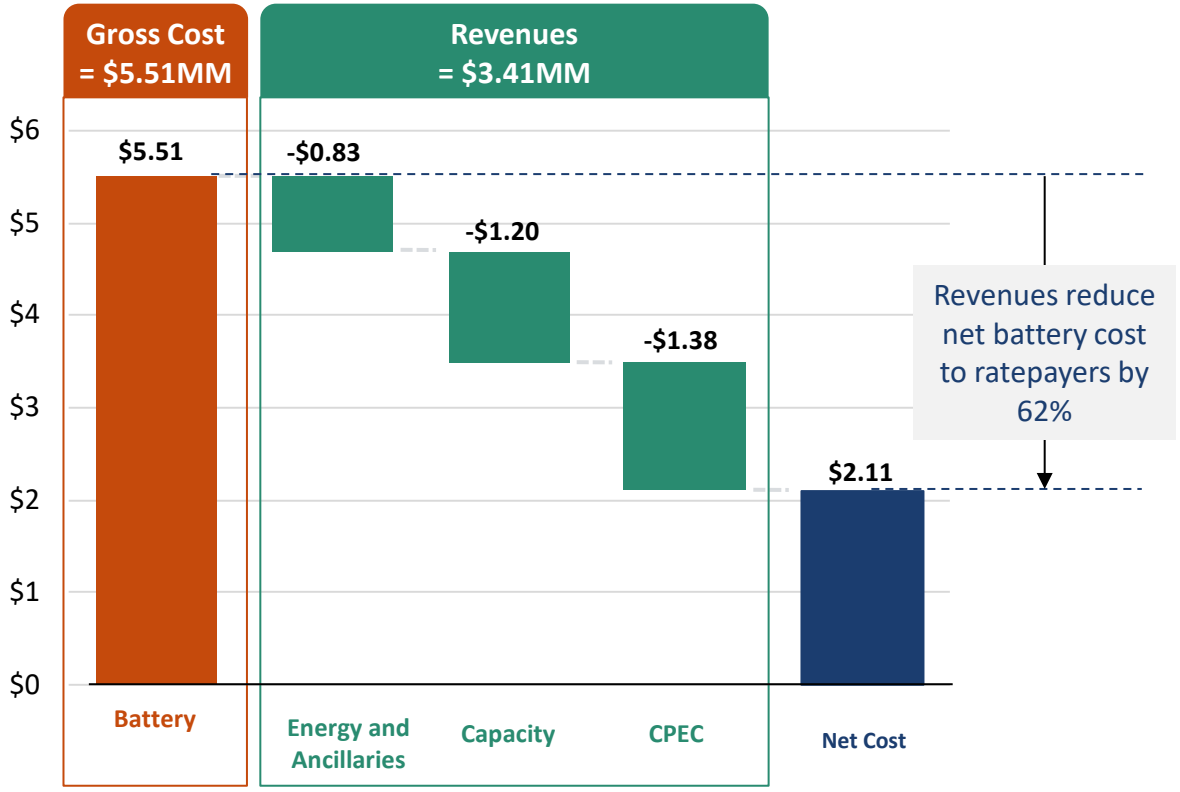
- Based on the historical outage patterns and load shape at this URD, battery operation would be able to **reduce outages by over 99%**
- Fully co-optimized market participation can offset the cost of the battery by generating **$3.4MM in revenues** over its lifetime
  - These revenues **reduce the NPV of gross cost revenue requirement by 62%**

Counterfactual Case:

Without the battery, a traditional reliability solution for this location would likely involve undergrounding the feeder at potential cost around $24.3 MM. Due to the high cost, this solution is unlikely to be implemented. Therefore, we frame the reliability use case analysis in terms of the net cost of improving reliability, rather than as a benefit cost analysis.

NET BATTERY COST IN THE DISTRIBUTION RELIABILITY USE CASE

NPV IN 2027$ MILLIONS



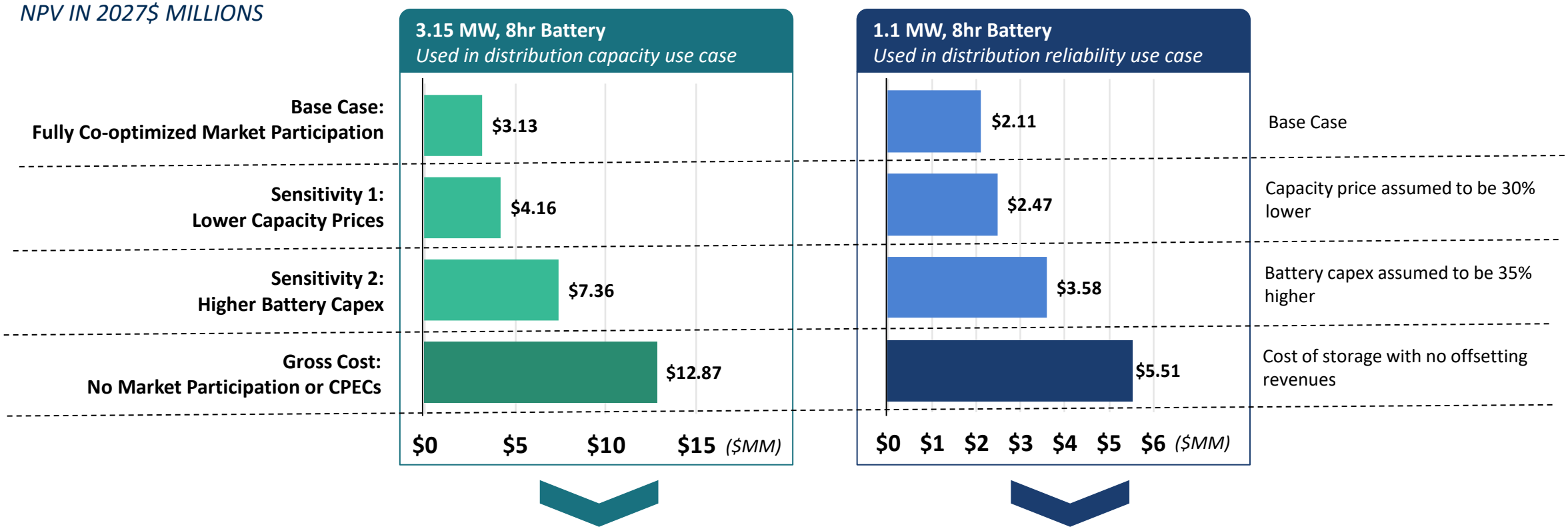
Note: Battery cost refers to all revenue requirements, including depreciation, O&M, return on rate base, and interconnection costs including reclosers.

Sensitivity Analysis on Battery Net Cost

The net battery cost is sensitive to the assumed battery capital cost and forecasted market prices. Sensitivity analysis shows that if capacity prices are 30% lower than modeled, net cost would be $4.2MM in the Capacity Case and $2.5MM in the Reliability Case. If battery capital cost is 35% higher, net cost would be $7.4MM in the Capacity Case and $3.6MM in the Reliability Case.

NET COST OF BESS ASSET ACROSS SELECTED SENSITIVITIES

NPV IN 2027$ MILLIONS



Provides $7.72MM in distribution capacity value by deferring the wires upgrade

Reduces outages from five 3-hr outages/yr to less than a minute of outage/yr

Summary of Battery Operational Capabilities

- A battery storage asset can serve the targeted distribution capacity and distribution reliability needs
  - A 3.15 MW, 8hr battery can meet forecasted distribution capacity needs on the studied feeder until 2035
  - A 1.1 MW, 8hr battery can improve reliability at the central MA URD site. If the battery had been in place for the past 5 years, it would have met 100% of URD load during outages if fully reserved for reliability purposes, and 99.5% of URD load if optimized for wholesale market participation.
- If the battery dispatch is optimized for market and state program participation outside of distribution need periods the associated revenues can reduce customer rate impacts
  - For the capacity need, revenues can reduce the NPV utility revenue requirement for the BESS by up to 76%
  - For the reliability need, revenues can reduce the NPV utility revenue requirement for the BESS by up to 62%
  - The largest BESS revenue opportunities are in CPECs and the capacity market
- These projections are developed under reasonable assumptions about the outlook for capital costs, wholesale capacity and energy prices, and CPEC prices. Nevertheless, the results are robust to some major deviations from these assumptions, as demonstrated in the sensitivity cases

The Key to Market Participation In Practice

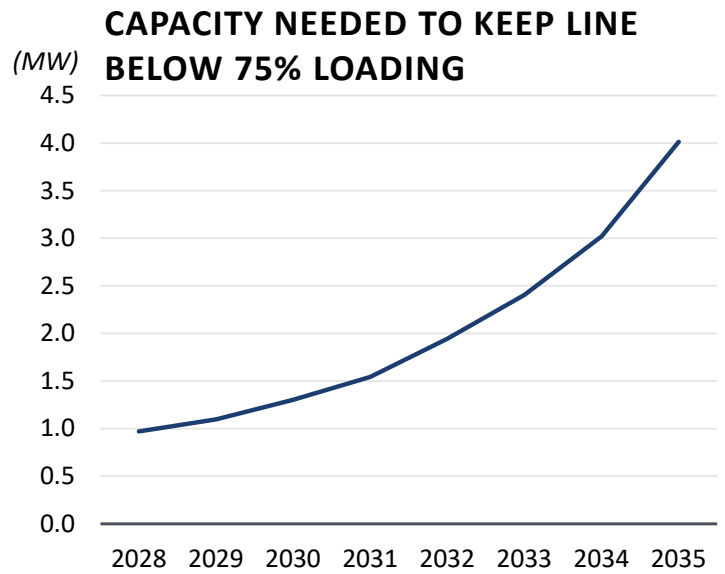
- Under perfect foresight, our modeling found limited trade-offs between meeting the goals of the primary use case for the storage asset and market participation
  - We found 0.2% revenue tradeoff from wholesale market-only operations in the distribution capacity case. This is due to a strong coincidence between the capacity need hours (high-demand evening hours), the CPEC window (between 4-9pm on weekdays), and CSC events (all historical events took place between 4:30pm and 8:30pm)
  - The distribution reliability tradeoff was also limited, with market participation leading to insufficient state of charge in the battery for less than 0.5% of intervals with outage conditions
- In reality, participation in markets would involve imperfect foresight and carry operational risks that may lead to higher revenue trade-offs than modeled here
- To ensure beneficial co-optimized battery operation for distribution system needs and wholesale markets, sophisticated control, forecasting, and dispatch systems should be in place, along with dedicated utility staff to manage operations
- Better incentive mechanisms should be in place to ensure cost offsetting for customers through mechanisms like revenue sharing or benefit sharing, which provide utilities with operational incentives

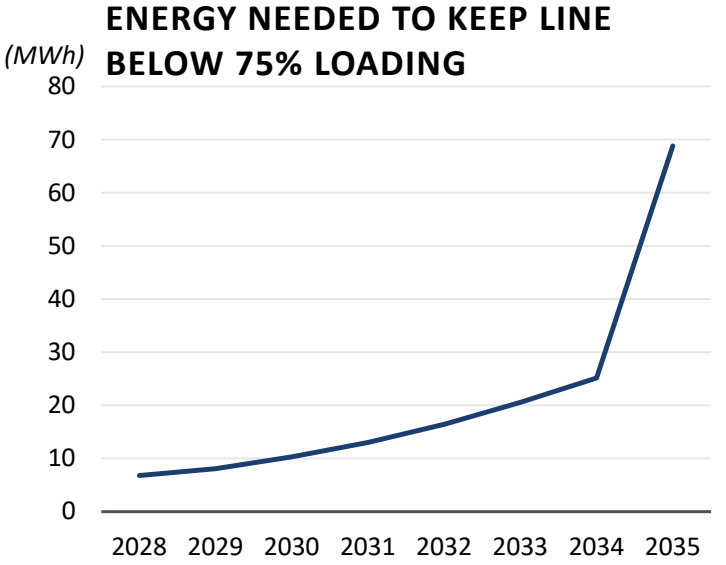
Additional Detail on Distribution Capacity Use Case

Distribution Capacity Case

The setup for the distribution capacity case prioritizes reducing feeder load to 75% of the line rating for as many years as possible

- The studied feeder in northeastern MA has a line rating of 12.4 MW in the summer and 13.2 MW in the winter, leading to a **summer planning threshold of 9.3 MW** (9.9 MW winter)
  - Based on the feeder load forecast, the feeder capacity and energy needs are expected to grow steadily until 2035, when the feeder energy needs begin to grow rapidly
- Based on the load profile, a **3.15 MW, 8hr duration battery** can keep the feeder load at or below 75% of its line rating through 2034
  - Longer deferral would require a much higher duration battery, which is not typical for non-wires solutions at this time and is unlikely to be cost-effective
- Battery dispatch for distribution needs require a limited amount of energy from the battery. After distribution needs are met, we optimize the battery to earn market and program revenues in the remaining hours.
  - The battery is used to meet distribution needs on 118 days in 2034, but the capacity needs are much smaller than the battery size so the total energy need is equivalent to ~16 cycles





Massachusetts Electric Company and Nantucket Electric Company
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D.P.U. 26-106
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Opportunities to Offset Battery Costs

We model revenue opportunities to offset the storage cost, estimating the payments for coordinated participation in wholesale markets and state programs, while also meeting distribution grid needs.

Revenue Stream	Description	Modeling Representation
Energy	Wholesale market arbitrage value can be captured from charging in lower-priced hours and discharging in higher-priced hours	Based on hourly (8760) wholesale market price shape
Ancillary Services	The battery can provide regulation and spinning reserves	Based on a battery net revenue premium (on top of energy revenue) developed from historical ancillary market prices
Clean Peak Standard	Batteries can generate Clean Peak Energy Certificates (CPEC), allowing National Grid to avoid the alternative compliance payment or sell the certificates	Charging is restricted to pre-defined renewable generation hours, battery dispatch is co-optimized against the value of a certificate in hours where CPECs are generated
Generation Capacity	Capacity value comes from participation in the capacity auction and performance during capacity scarcity condition (CSC) hours	Capacity market payments are adjusted for the expected CSC penalties/bonuses based on the historical events

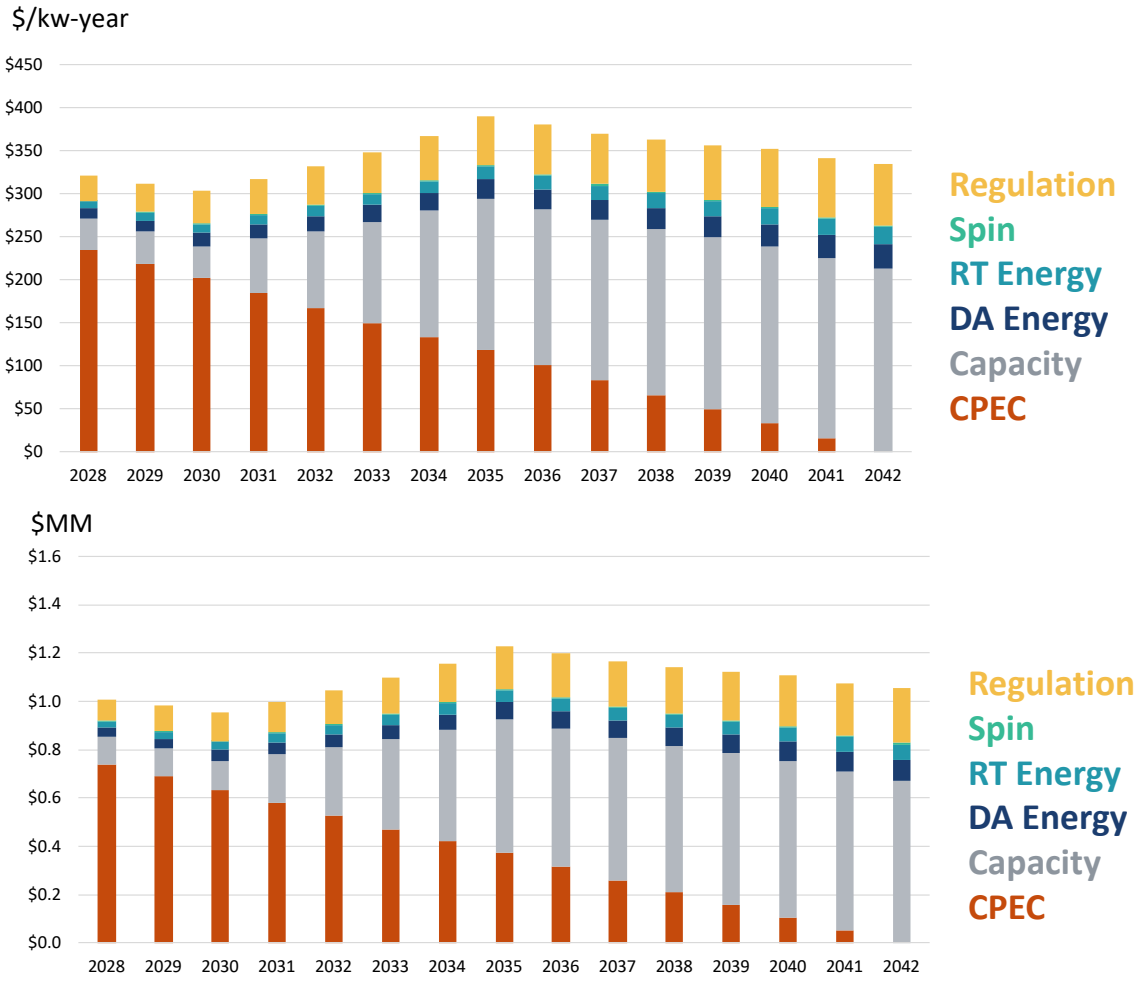
Distribution Capacity Case: Revenue Stack

The battery prioritizes deferral while co-optimizing participation in wholesale markets with CPEC generation, earning an estimated $341/kW-yr in levelized net revenues

- The largest share of net revenues comes from CPECs, which we conservatively model with a declining certificate value over the battery lifetime
- Wholesale market revenues, particularly for capacity, are expected to grow in the mid-2030's
  - Growth is tied to forecasted capacity price increases
  - Capacity market revenues also include an estimate of performance penalties/bonuses from dispatch during CSC events based on modeled historical performance during actual CSC events in the 2021-2025 period
- With this strategy, the battery averages 240 cycles per year, captures 99.97% of CPEC value, and earns ~$80k in CSC overperformance bonus payments
  - The strategy takes a small ~$20k (0.21%) revenue trade off compared to a scenario with no deferral-related dispatch

FORWARD ANNUAL NET REVENUE

Distribution Capacity Case



Distribution Capacity Case: Net Benefit of Storage

Market and program participation benefits make a storage solution cost-beneficial across a variety of participation and sensitivity scenarios

- The net benefits to ratepayers from the storage solution ranges from $0.4 MM to $4.6 MM across the sensitivity cases
  - The conservative capex case, representing 35% higher storage costs, has the lowest net benefits but still offers a BCA ratio of 1.02
  - The conservative capacity price case, representing 30% lower capacity prices, demonstrates the robustness of the results to market revenues, with a BCA ratio of 1.3

NPV OF STORAGE COSTS AND BENEFITS

NPV IN 2027$ MILLIONS

Scenario	Base Case	Conservative Capex	Conservative Capacity Price
[A] BESS Capital Cost	10,075,005	13,535,526	10,075,005
[B] BESS O&M	2,222,377	2,985,710	2,222,377
[C] Interconnection Cost	574,087	574,087	574,087
[D = A + B + C] BESS Revenue Requirement	12,871,469	17,095,324	12,871,469
[E] E&AS Revenues	2,356,778	2,356,778	2,356,778
[F] Capacity Revenues	3,434,410	3,434,410	2,404,087
[G] CPEC Revenues	3,946,183	3,946,183	3,946,183
[H = D-E-F-G] Net Revenue Requirement	3,134,098	7,357,952	4,164,421
[I] Net Deferral Value	7,716,359	7,716,359	7,716,359
[J = I-H] Net Benefit of Storage	4,582,261	358,407	3,551,938

Note: Demand charges were considered but not included as they would be revenue neutral (paid from and to National Grid).

Additional Detail on Distribution Reliability Use Case

Distribution Reliability Case

The setup for the distribution reliability case prioritizes avoiding interrupted service for customers due to feeder outages

- In the historical period (2021-2025), the studied central MA URD feeder had an average of 16 outage hours per year, with the typical event lasting 2 hours and the max just over 8 hours
  - The distribution feeder is vulnerable to vegetation, equipment, and weather-related outages, leaving customers served by the line exposed to service interruptions
  - The load at the central MA URD peaks at 1.1 MW, with an assumed hourly shape based on the National Grid load forecasting team's average residential load profile
- Based on the magnitude and duration of outages, we model a **1.1 MW, 8hr duration battery**, which is large enough to serve all customers during the historical outages
- To evaluate the battery performance, we model storage performance with two operational strategies – reliability-only operation or market participation
  - We model performance during historical outages and reflect in the forward period with an assumption of the same outage conditions
- We assume the battery can be used to avoid interrupted service for its lifetime (15 years), after which time another investment would be needed to continue to provide reliability value

MODELED OPERATIONAL STRATEGIES

Scenario	Implementation
Reliability-Only	Completely withhold the battery, only discharge during outages
Market Participation	Allow full market participation, use ex-post SOC to see if battery could have met reliability need

Note: All scenarios assume perfect foresight of outages. Market Participation uses the state of charge (SOC) to identify ability to cover the need but does not update the SOC ex-post following an outage served.

Opportunities to Offset Battery Costs

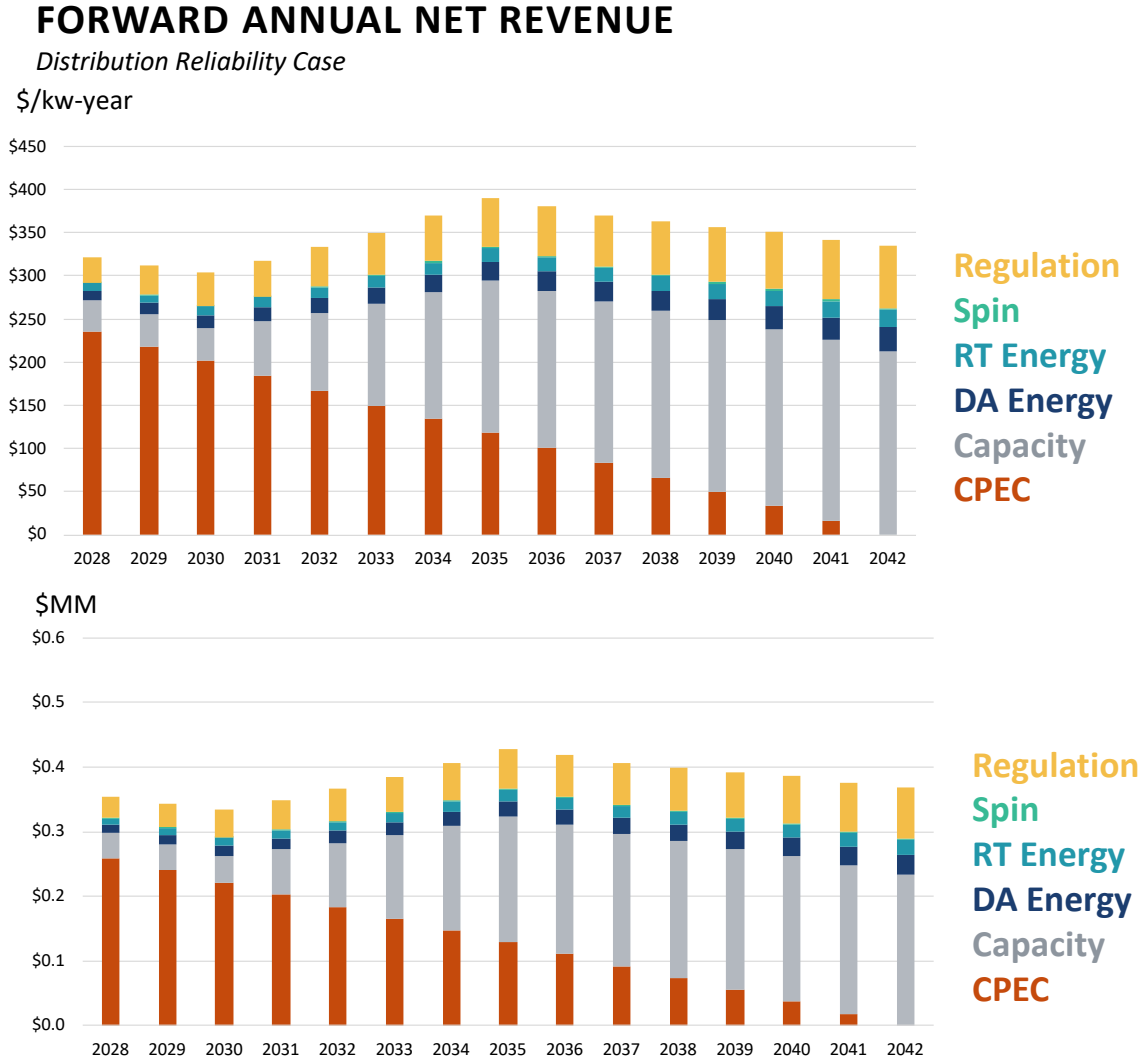
We model revenue opportunities to offset the storage cost, estimating the payments for coordinated participation in wholesale markets and state programs, while also meeting distribution grid needs.

Revenue Stream	Description	Modeling Representation
Energy	Wholesale market arbitrage value can be captured from charging in lower-priced hours and discharging in higher-priced hours	Based on hourly (8760) wholesale market price shape
Ancillary Services	The battery can provide regulation and spinning reserves	Based on a battery net revenue premium (on top of energy revenue) developed from historical ancillary market prices
Clean Peak Standard	Batteries can generate Clean Peak Energy Certificates (CPEC), allowing National Grid to avoid the alternative compliance payment or sell the certificates	Charging is restricted to pre-defined renewable generation hours, battery dispatch is co-optimized against the value of a certificate in hours where CPECs are generated
Generation Capacity	Capacity value comes from participation in the capacity auction and performance during capacity scarcity condition (CSC) hours	Capacity market payments are adjusted for the expected CSC penalties/bonuses based on the historical events

Distribution Reliability Case: Revenue Stack

The battery co-optimizes participation in wholesale markets with CPEC generation and discharges to provide reliability value based on available energy when outages occur, earning an estimated $342/kW-yr in levelized net revenues

- The largest share of net revenues comes from CPECs, which we conservatively model with a declining certificate value over the battery lifetime
- Wholesale market revenues, particularly for capacity, are expected to grow in the mid-2030's
  - Growth is tied to forecasted capacity price increases
  - Capacity market revenues also include an estimate of performance penalties/bonuses from dispatch during CSC events based on modeled historical performance during actual CSC events in the 2021-2025 period
- With this strategy, the battery averages 240 cycles per year and earns ~$1k in CSC overperformance bonus payments



Distribution Reliability Case: Net Revenue Requirement

Market and program participation benefits can offset the revenue requirement of a battery across a variety of participation and sensitivity scenarios

- Market participation can provide significant value to offset the capital costs associated with the battery
  - Based on the sensitivity, the market participation revenues can reduce the NPV revenue requirement between 49% and 62%
- With market participation, there is a small share (0.5%) of service interruptions that the battery cannot cover

NPV OF STORAGE COSTS AND BENEFITS

NPV IN 2027$ MILLIONS

	Reliability Only	Market Participation		
Scenario	**Base Case**	**Base Case**	**Conservative Capex**	**Conservative Capacity Price**
[A] BESS Capital Cost	3,518,256	3,518,256	4,726,692	3,518,256
[B] BESS O&M	776,068	776,068	1,042,629	776,068
[C] Interconnection Cost	1,219,935	1,219,935	1,219,935	1,219,935
[D = A + B + C] BESS Revenue Requirement	5,514,259	5,514,259	6,989,256	5,514,259
[E] E&AS Revenues	-	829,645	829,645	829,645
[F] Capacity Revenues	-	1,199,318	1,199,318	839,522
[G] CPEC Revenues	-	1,378,507	1,378,507	1,378,507
[H = D-E-F-G] Net Revenue Requirement	5,514,259	2,106,789	3,581,786	2,466,584

Note: Demand charges were considered but not included as they would be revenue neutral (paid from and to National Grid).

Market Price and Clean Peak Standard Assumptions

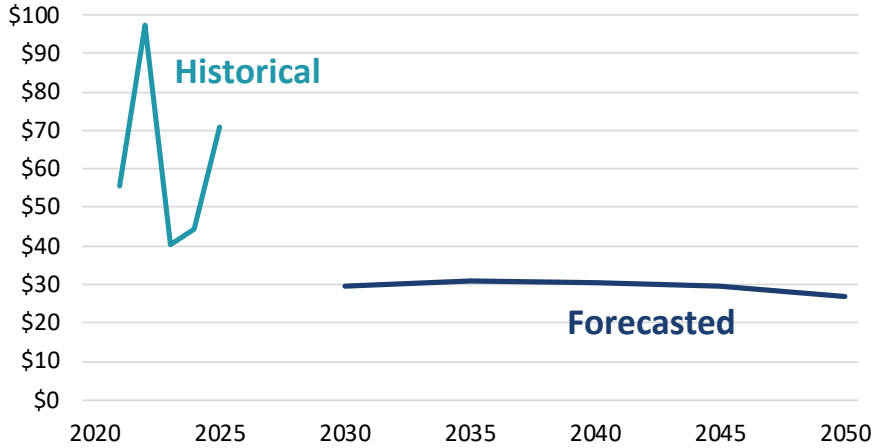
Energy

Wholesale energy prices determine the energy arbitrage opportunity for storage

- The NLR Cambium forwards provide energy prices consistent with all state, regional, and federal policies as of August 2024
  - Cambium also produces generation capacity and system load profiles that are consistent with the energy prices
- The average diurnal shape of the Cambium prices has enough intra-day volatility to provide the battery with daily arbitrage opportunities

ANNUAL AVERAGE DAY AHEAD ENERGY PRICES

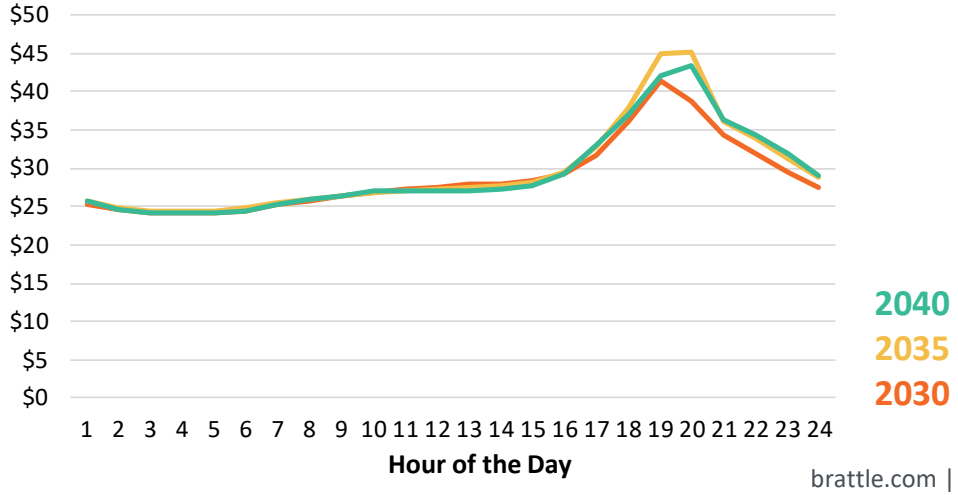
$/MWh (2027$)



Notes: Historical Prices from ISO-NE LMP DAH NEMASSBOST node. Forward Prices from Cambium 2024 BA131 (Massachusetts).

AVERAGE DAY AHEAD ENERGY PRICE DAILY SHAPE

$/MWh (2027$)



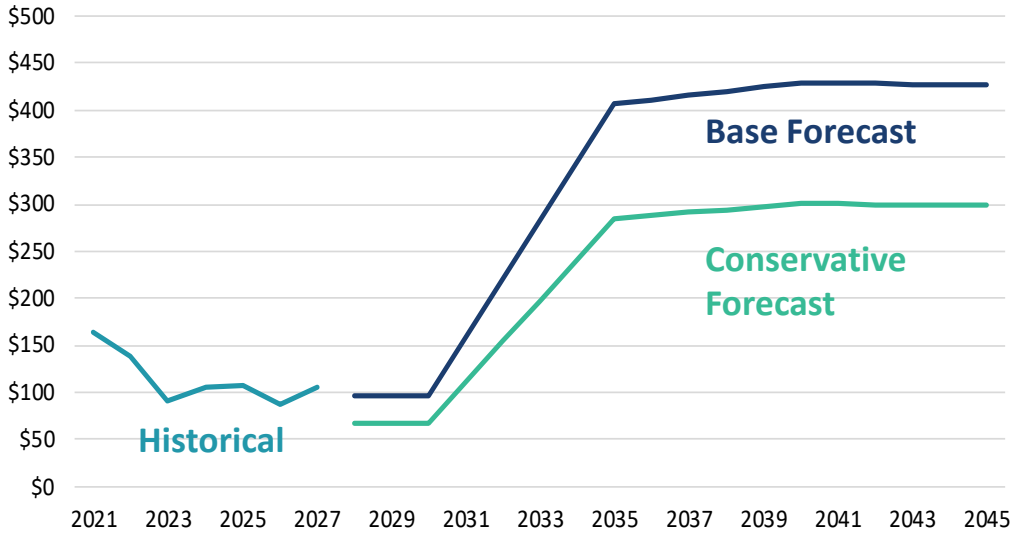
Generation Capacity

Generation capacity revenue is the sum of capacity market payments and the bonus/penalty from performance during capacity scarcity condition (CSC) hours

- Capacity market payment depends on the accredited capacity of the battery and the market clearing price
  - In the last FCM auction, storage was accredited at its maximum capacity if it had >=2hr duration; we use this approach in this study.
  - ISO-NE is currently reforming its storage accreditation methodology to better capture longer duration needs[1]. In this reformed framework, battery accreditation will depend on stored energy in marginal reliability impact ("MRI") hours. The new approach means longer duration batteries will see benefits from duration, compared to the previous process that was only based on a 2-hour period.
  - ISO-NE is also proposing capacity market reforms to transition to a seasonal capacity market structure[2]. This study reflects the current market structure and does not attempt to forecast battery revenues under potential new market structures.
- The CSC bonus/penalty compensates for the battery's generation above the capacity supply obligation or charges for generation below the obligation at the capacity performance payment rate
  - The capacity supply obligation depends on the accredited capacity and the system need during the event
- In the past five years, there have only been 88 5-minute CSC intervals

ACTUAL HISTORICAL AND FORECAST FORWARD CAPACITY PRICES

*$/MW-day (real$), f*rom ISO-NE FCM and Cambium 2024 BA131 (Massachusetts)



HISTORICAL CAPACITY SCARCITY CONDITION (CSC) EVENTS

Date	Start Time	# of 5-min Violations
6/24/2025	17:35-20:35	37
8/1/2024	16:55-19:20	22
6/18/2024	17:50-18:15	6
7/5/2023	18:25-18:50	6
12/24/2022	16:40-18:00	17

Source: Auction Reports and Supporting Data

1 Section III.13.7.2 of Market Rule 1 and Energy Storage Resource Modeling and Accreditation Memo; 2 Capacity Auction Reforms Key Project

Clean Peak Standard

The Clean Peak Standard requires a share of Massachusetts utilities' total annual energy consumption to be covered by Clean Peak Energy Certificates (CPECs), either generated from asset dispatch, purchased bilaterally, or offset through the alternative compliance payment

- A battery can earn CPECs by charging during the predefined windows of high renewable generation and dispatching during predefined daily peak windows and the monthly peak hour
- The MWh of electricity generated during the peak windows is translated into credits after scaling by multipliers (see table)
- Reporting on CPEC value from existing resources and MA solicitations have reported ~$150 - $430/kW-yr in revenue from selling or using the certificates

See Clean Peak Certificate Generation for additional information. Discussed in MassCEC and DOER storage report and CHP case study.

CPS SEASONAL CHARGING AND PEAK WINDOWS

Clean Peak Season	Energy Storage Charging Windows		Seasonal Peak Periods
	Wind-Based	Solar-Based	
Spring	12am – 6am	8am – 4pm	5pm – 9pm
Summer	12am – 6am	7am – 2pm	4pm – 8pm
Fall	12am – 6am	9am – 3pm	4pm – 8pm
Winter	12am – 6am	10am – 3pm	4pm – 8pm

MULTIPLIERS ON PEAK PERIOD GENERATION

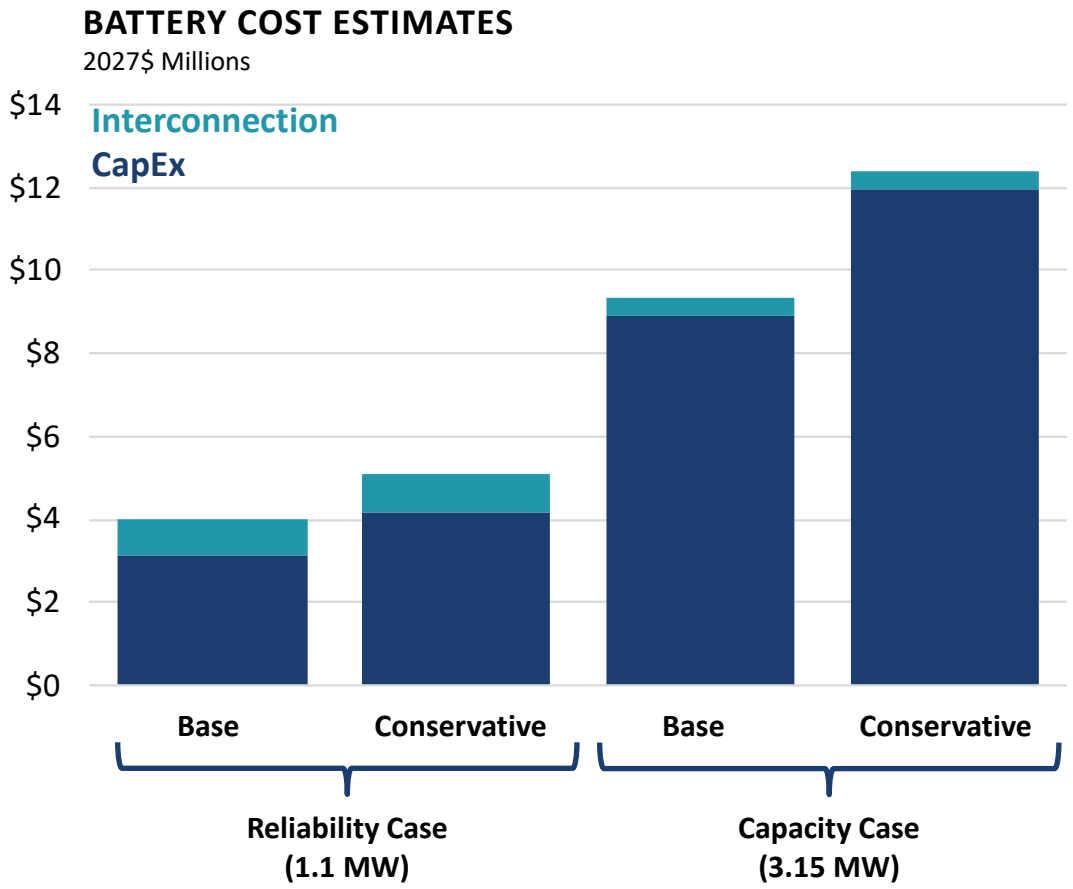
Description	Multiplier Value	Included?
Seasonal	Summer/Winter= 4 Spring/Fall = 1	Yes
Actual Monthly System Peak	25	Yes
Resilience	1.5	No
Existing Resource	0.1	No
Contracted Resource	0.01	No
SMART ES Resource	0.03	No
Distribution Circuit	2	No
Near-Term Resource	2	No

Source: 225 CMR 21.00: Clean peak energy portfolio standard (CPS) | Mass.gov

Battery Cost Assumptions

CapEx and Interconnection Costs

- **Battery capital expenditure** estimates are based on NLR's 2024 ATB for an 8-hour battery with a 2028 in-service date
  - **Base Cost Scenario:** ATB's Moderate, Commercial-Scale Case (project size is comparable to the commercial-scale project size assumed in ATB)
  - **Conservative Cost Scenario:** ATB's Conservative, Utility-Scale Case (higher cost per kW to serve as an upper bound)
- **Interconnection costs** specific to National Grid in Massachusetts were used instead of NLR ATB values



Note: Interconnection costs for the reliability case include the cost of reclosers that would be required to island the URD for it to be served by the battery.

Sources: 2024 NLR ATB and Massachusetts Typical System Modifications and Estimated Costs for DG Interconnection

Battery Dispatch Methodology and Examples

Methodology for Modeling Market Participation Trade-offs

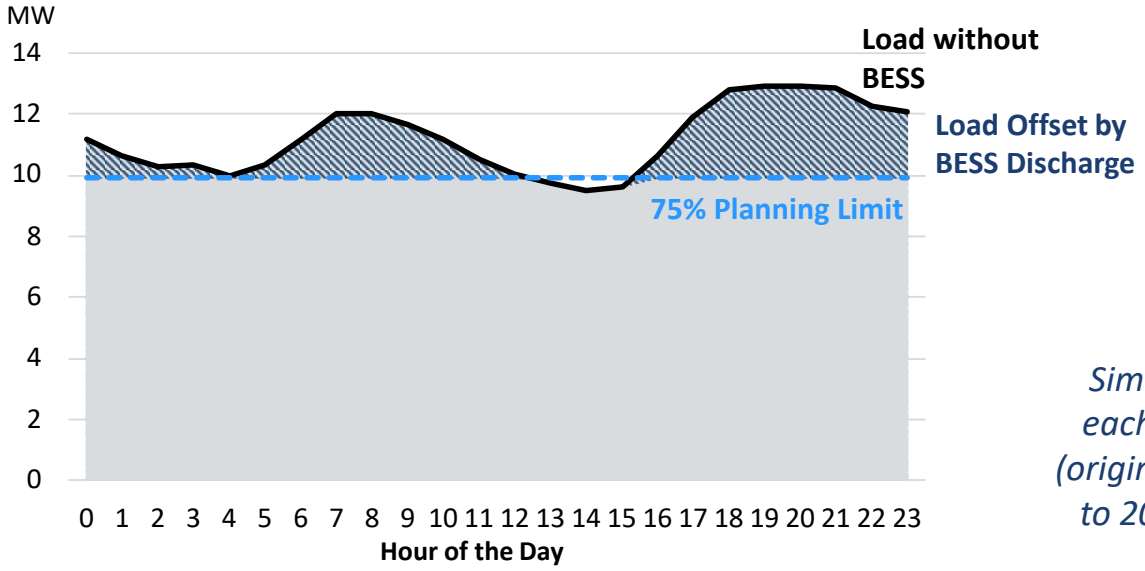
Our modeling approach uses simulated revenues based on observed historical market prices to account for additional market opportunities and co-optimization trade-offs that are not reflected in the Cambium energy price forecasts

1. Forward Revenue	2. Additional Revenue Impact from RT Energy, AS, and CSC	3. Addition of Program Value
Day ahead (DA) energy net revenue for the battery lifetime (2028 - 2042) is modeled based on the Cambium forecasted day-ahead market prices.	Forward DA revenue is adjusted to include the additional revenue that can be captured from the real time energy and AS markets and to account for the capacity performance bonus/penalty. The net revenue adjustments are based on revenues from a co-optimized dispatch on historical prices and capacity events.	The modeled DA forward dispatch is used to calculate the number of CPECs generated each year and the value of those certificates is added to the value stack.

Meeting the Distribution Capacity Need Using Storage

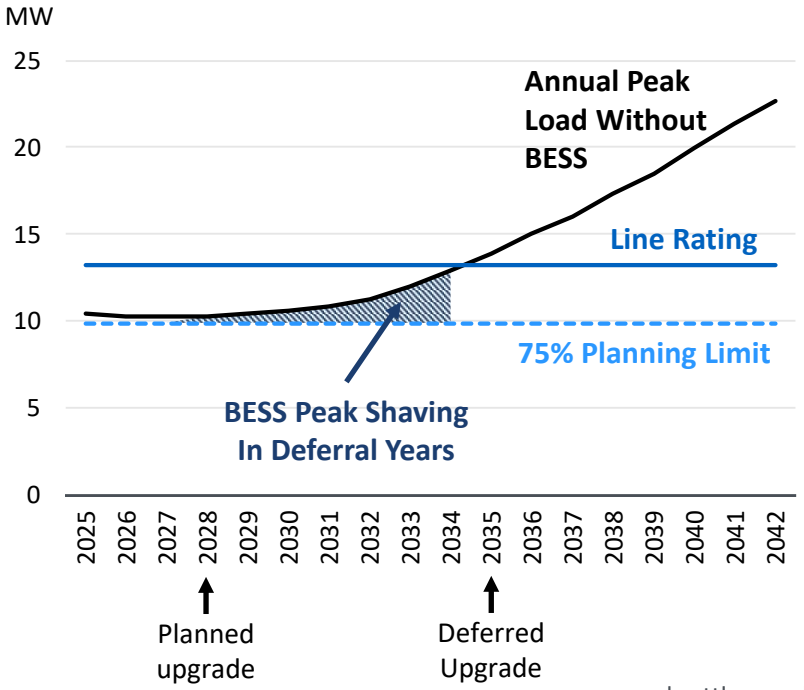
In the distribution capacity use case, the battery is modeled as prioritizing the distribution need by discharging whenever the feeder is more than 75% loaded. The battery is able to provide this service from 2028 to 2034. Beyond 2034, the battery would no longer be able to meet this objective because the magnitude and duration of load are expected to be too far over the planning limit in this location.

HOURLY LOAD ON PEAK DAY, 2034



Similar operation in each year from 2028 (original grid need date) to 2034 (final year of deferral)

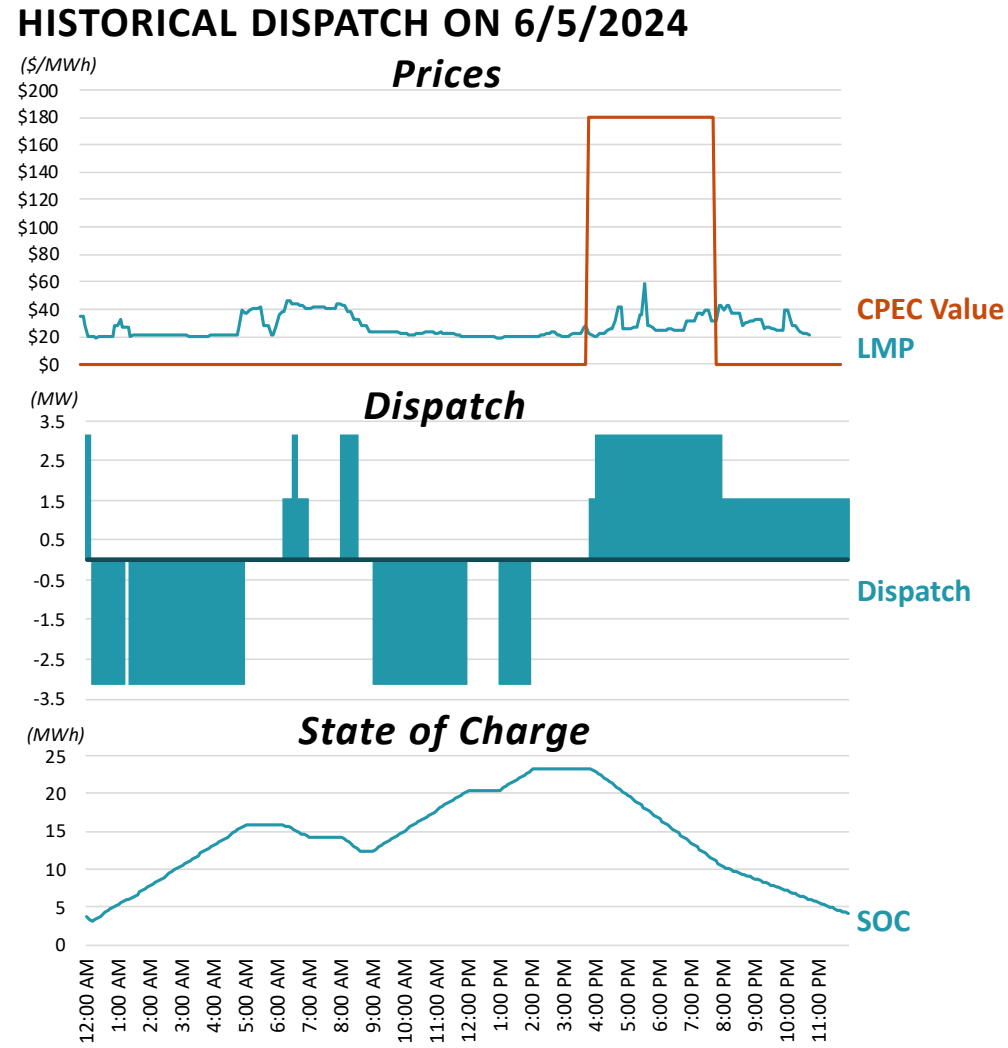
ANNUAL PEAK LOAD ON THE FEEDER



Revenue Opportunities: Sample Typical Day

On a typical day without any distribution capacity need, the battery operates to co-optimize arbitrage of energy market prices, AS market participation, and generation of CPECs

- The battery makes trade-offs as it co-optimizes between the value streams, but it does not have to hold energy for the distribution capacity need
- The operation of a battery on a typical day is aligned with how we would expect a developer-owned wholesale market participant to dispatch

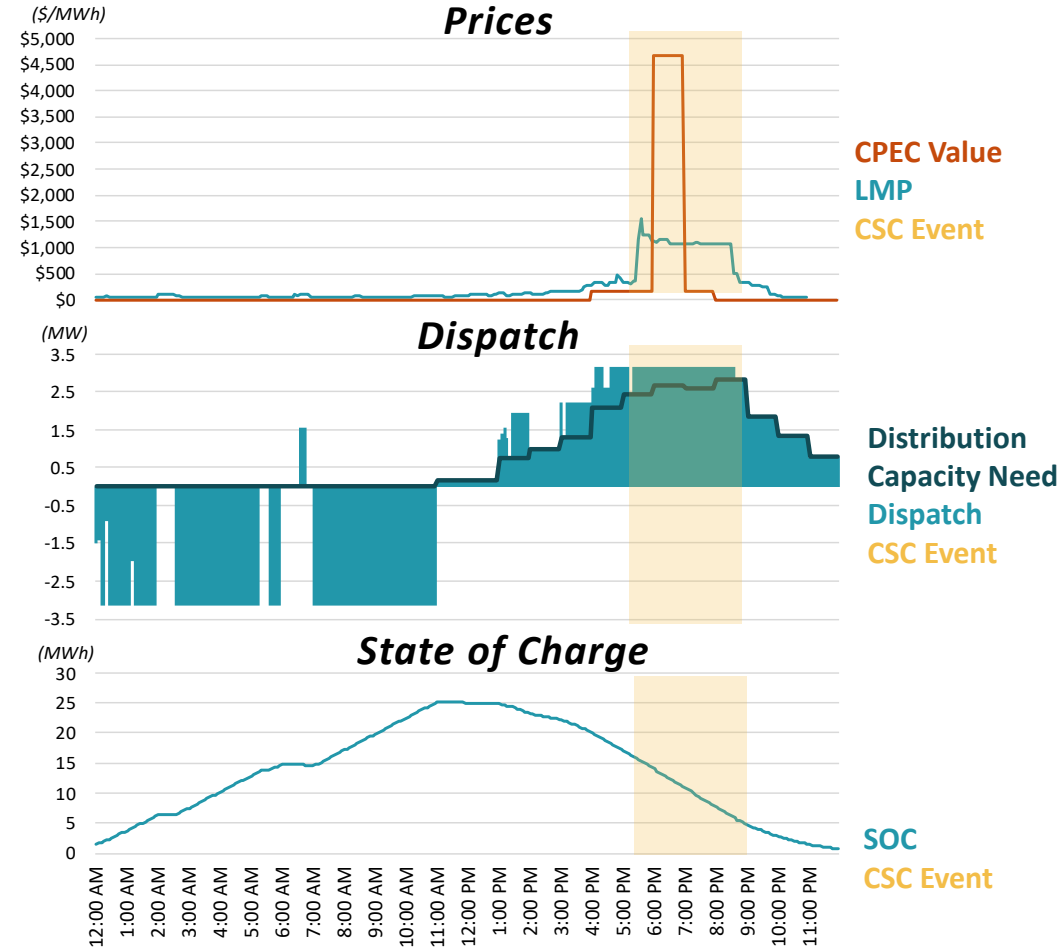


Revenue Opportunities: Sample Day of Aligned Grid Needs

At most times when there is a distribution need, the need also aligns with times of higher market prices. The battery is able to capture both parts of the value stack on this type of day.

- The tradeoff of revenue opportunity depends on the coincidence of the distribution capacity need, arbitrage opportunities, the CPEC peak window, and if relevant, the CSC event
- In periods when the distribution capacity need is below the capacity of the battery, it can meet the Dx need and still dispatch extra to capture CPEC and CSC value

HISTORICAL DISPATCH DURING 6/24/2025 CSC EVENT



Note: CSC price was $9,337/MWh for the duration of event.

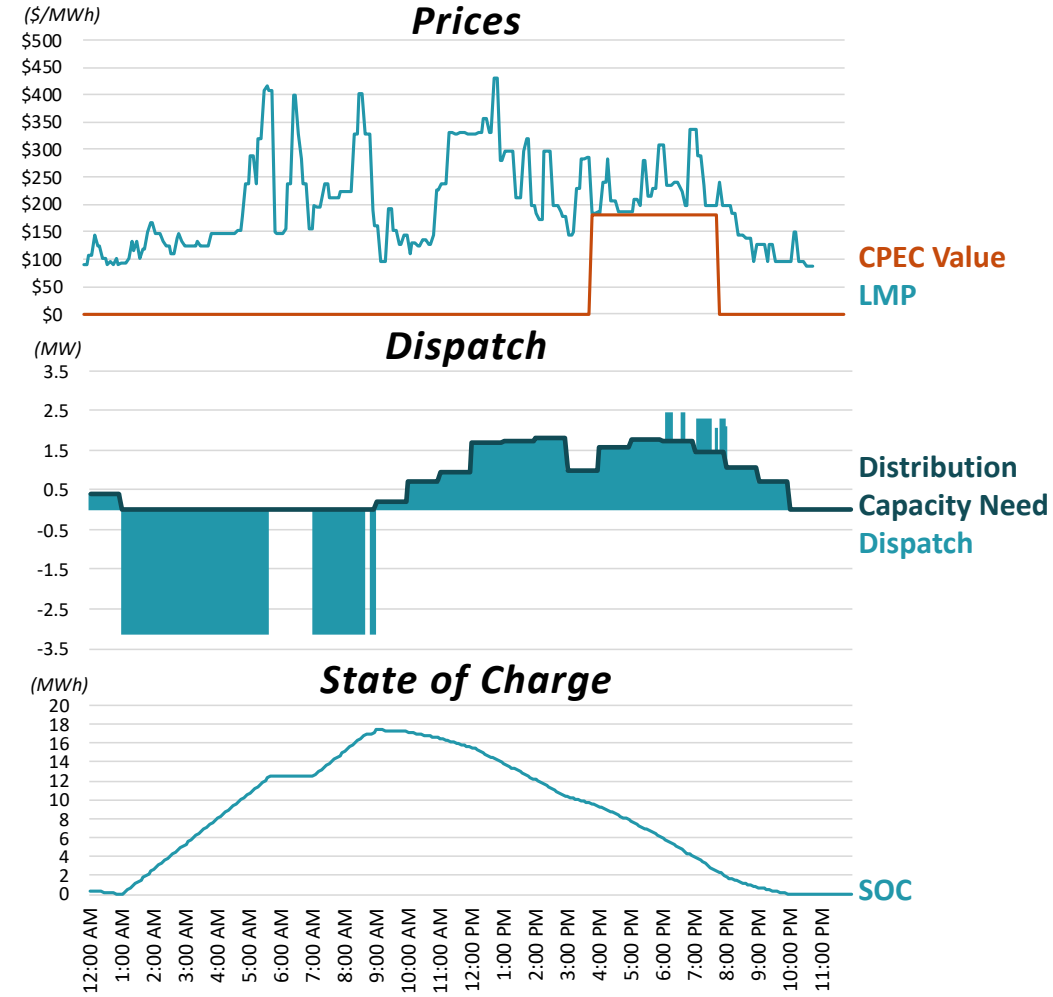
Revenue Opportunities: Sample Day With Revenue Tradeoff

On rare occasions, the distribution need requires the full capacity of the battery, and the market revenue tradeoff becomes more significant

- The battery must prioritize the distribution need to maintain system reliability
- Here, the battery has limited ability to arbitrage the prices or dispatch at capacity during the CPEC window
- This leads to a net revenue tradeoff when compared to a wholesale market-only participation strategy
- The overall tradeoff is very low because of the load characteristics of the selected feeder
- While the model is able to fully optimize battery dispatch due to perfect foresight, capturing similar value in real-world conditions will require National Grid to develop sophisticated capabilities

HISTORICAL DISPATCH WITH DISTRIBUTION CAPACITY NEED

8/9/2022



Market Participation Tradeoffs

The battery has a high level of value-stacking because of the coincidence of the value streams during peak periods

12/24/2022

- First CSC Event in the historical price series.
- Triggered by 30 min reserve constraint. Severe cold throughout the Northeast and unplanned outages.
- Not a CPEC business day, nor the monthly peak.

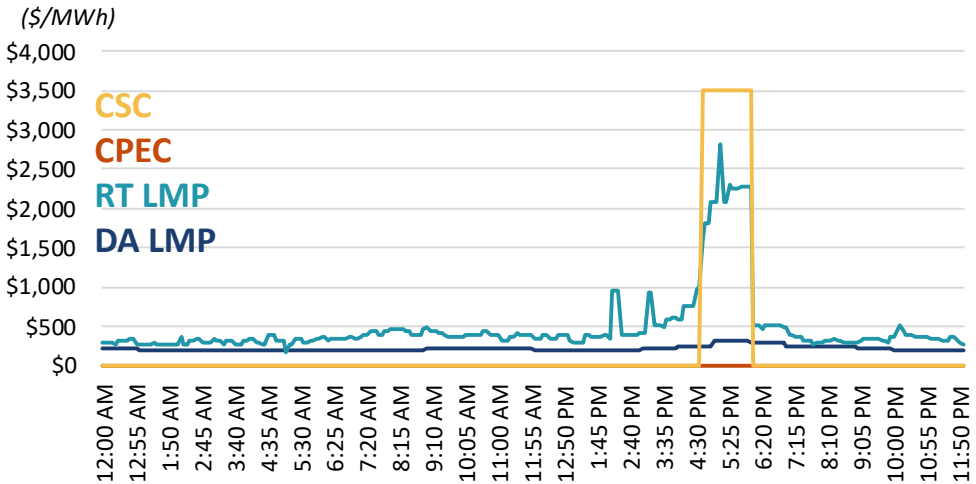
8/1/2024

- Combination of generator outages and higher temperatures and load than forecasted
- Monthly system peak occurs between 17:00 – 18:00 in between the CSC events.

This modeling is based on historical prices and capacity events. Future events may change with evolving or unpredictable system conditions.

See December 2022 CSC Event and August 2024 CSC Event

PRICE CONDITIONS ON 12/24/2022



PRICE CONDITIONS ON 8/1/2024

