ILLINOIS MUNICIPAL ELECTRIC AGENCY
BATTERY ENERGY STORAGE SYSTEM FEASIBILITY STUDY

MARCH 17, 2026

List of Acronyms

ACP – American Clean Power (Association)

BESS – Battery Energy Storage System

BOT - Build Operate Transfer

BTMG – Behind-The-Meter-Generation

CEJA - Climate and Equitable Jobs Act

COD – Commercial Operation Date

CRGA – Clean and Reliable Grid Affordability Act

DLOL – Direct Loss of Load

DOE- Department of Energy

DY – Delivery Year

EIA – Energy Information Administration

ELCC – Effective Load Carrying Capability

EPA – Environmental Protection Agency

EPC - Engineering, Procurement, and Construction

ERCOT - Electric Reliability Council of Texas

ESSA – Energy Storage Service Agreement

FEOC - Foreign Entity of Concern

FERC – Federal Energy Regulatory Commission

GDS – GDS Associates, Inc.

GIA - Generator Interconnection Agreement

GW - Gigawatt

IFC – International Fire Code

IMEA – Illinois Municipal Electric Agency

IRA - Inflation Reduction Act of 2022

ITC - Investment Tax Credit

LFP – Lithium-Iron-Phosphate

LNMC – Lithium-Nickel-Manganese-Cobalt

LSE- Load Serving Entity

MACR - Material Assistance Cost Ratio (calculation)

MISO – Midcontinent Independent System Operator

MP – Market Participant

MVA – Mega Volt-Ampere

MW – Megawatt

NFPA – National Fire Prevention Association

NRBTMG – Non-Retail Behind-The-Meter-Generation

OBBBA - One Big Beautiful Bill Act of 2025

PFE - Prohibited Foreign Entity

PJM – PJM Interconnection – Pennsylvania-New Jersey-Maryland Interconnection

PTC - Production Tax Credit

RFP – Request For Proposal

RPS – Renewable Portfolio Standard

RTE – Round Trip Efficiency

RTO – Regional Transmission Operator

SCADA - Supervisory Control And Data Acquisition

Executive Summary

The Illinois Municipal Electric Agency Board of Directors has adopted a Sustainability Plan with a goal of net-zero carbon emissions by 2050. One of the key components of the plan for transitioning and diversifying IMEA's portfolio was the directive to study the feasibility of installing a utility-scale, behind-the-meter Battery Energy Storage System (BESS) on member distribution systems. Subject to Board approval, implementation of a BESS would be expected to occur by 2030. In this comprehensive study, grid-connected BESS will also be discussed, and staff will continue to search for advantageous large-scale projects. But given that these projects require proceeding through a lengthy interconnection process, IMEA will rely on market offers from developers before studying grid-connected BESS.

This study comes at a critical juncture for the electric grid in the United States. The retirement of aging dispatchable thermal generators has coincided with unprecedented demand growth from electrification, reindustrialization, and a surge in energy-intensive data centers. At the same time, the addition of intermittent generation resources has introduced a new dynamic that increases reliability risks. The inherent weather dependence of intermittent generation has caused reliability risk to shift from times when energy demand is at its highest, a concept known as "peak load," to times when the difference between energy demand and intermittent generation is at its highest, a concept known as "net peak". BESS's ability to support the grid with stored energy gives it a useful role in the diverse resource mix critical to ensuring reliability as IMEA transitions to a net-zero future, while meeting the state and federal clean energy requirements.

This report provides a comprehensive overview of BESS, beginning with the impetus for this study and its goals. It then examines BESS fundamentals, safety considerations, costs and benefits of BESS, and concludes with recommendations to the IMEA Board on next steps. The analysis incorporates both technical and market considerations, offering context for how BESS can complement IMEA's short- and long-term planning while aligning with ever-evolving BESS technology development, safety advancements, and economic efficiencies. The study is designed to explain what BESS is, how it functions, and to evaluate whether the resource is a practical and strategic fit for IMEA at this time.

BESS Fundamentals

There are many different types of BESS in the market and under development today ranging from lithium-ion to the emerging technologies of vanadium redox flow and solid-state batteries. Each technology brings its own advantages and disadvantages in relation to safety, efficiency, and cost. Lithium-ion is the current market leader because of its high energy density and efficiency, as well as its cyclability, durability and scalability. Disadvantages include its cost as compared to traditional, dispatchable resources, risk of thermal runaway, and end-of-life uncertainties. Today, lithium-ion BESS are typically configured to have a duration of four hours to strike the balance between revenue streams and the capital costs that increase along with longer durations.

Safety

The most notable safety concern for lithium-ion BESS is thermal runaway, which occurs when a defective lithium-ion battery cell's internal temperature rises uncontrollably, resulting in deep-seated, difficult to extinguish fires[1]. In recent years, several high-profile instances of thermal runaway have prompted a thorough review of industry standards, which have since been reworked and formalized in an effort to address the risks posed by thermal runaway and BESS[2]. Recent technological advancements have been designed to mitigate safety concerns by offering additional monitoring and automation to detect and combat increasing temperatures. Improved containment designs and fire suppression systems are now available to hinder the spread of excessive heat and fires[3].

Fires in lithium-ion systems can also cause the release of toxic emissions in the air and in water runoff[4]. While it is still unclear what effects these emissions have on first responders, nearby residents, and the surrounding environment, it is crucial to be prepared to safely and effectively extinguish fires should they occur. Regulatory standards from the Department of Energy (DOE), International Fire Code (IFC), National Fire Protection Association (NFPA), Environmental Protection Agency (EPA), and individual battery manufacturers have all been developed to inform of best practices.

Cost and Benefit Analysis

The report details capital costs, efficiency profiles and operational expenses associated with BESS. It considers different ownership models, including outright IMEA ownership as well as offtake agreements with third-party developers, assessing the advantages and trade-offs to each approach. In terms of benefits, the study highlights how BESS can create revenue streams through ancillary services, energy arbitrage, load netting and capacity accreditation. A financial analysis framework is also presented to illustrate the long-term

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[1] https://ul.org/research-updates/what-is-thermal-runaway/
[2] https://www.epa.gov/electronics-batteries-management/battery-energy-storage-systems-main-considerations-safe
[3]https://www.sciencedirect.com/science/article/pii/S2352152X24009459#:~:text=Building%20on%20previous%20research%20on,2022%20presented%20in%20%5B17%5D.
[4] https://www.nfpa.org/education-and-research/research/fire-protection-research-foundation/projects-and-reports/environmental-impact-of-li-ion-incidents-compared-to-other-types-of-fires

value proposition and potential risks. The report also includes findings from GDS Associates, Inc. – an outside consultant – complete with sensitivities associated with the project.

While battery capital costs have seen reductions over the past decade[5], economic viability remains uncertain. Legislation, tariffs and other forms of regulation have created production cost uncertainties and amplified supply chain concerns. Participating in a BESS via an offtake agreement will provide firm pricing and limit IMEA's responsibilities and risks, thereby outweighing the theoretical advantages of ownership.

The economic benefits of batteries are diverse, but not without uncertainty. This study focuses on the four main revenue streams which support the development of BESS:

1. Providing ancillary services, such as frequency regulation
2. Energy arbitrage, or, charging the BESS when energy prices are low and discharging when energy prices are high
3. Load netting, which is the practice of discharging the BESS during hours of peak energy demand in order to reduce the Agency's Regional Transmission Organization (RTO)-imposed transmission charges and capacity requirements
4. Capacity payments, which a resource receives from the RTOs for its ability to contribute to overall system reliability

Ancillary services have historically served as a reliable and stable cost recovery mechanism in Pennsylvania-New Jersey-Maryland Interconnection (PJM) markets, but recent changes to that construct have put its viability as a revenue stream at risk going forward. Even still, a BESS can continue to seek revenue from ancillary services during those limited periods when it is more economic to provide ancillary services instead of seeking energy arbitrage opportunities.

Capitalizing on energy arbitrage another key source of revenue from BESS, requires, in addition to a spread between low and high energy prices, the ability to accurately predict the optimal times to charge and discharge.

Load netting is becoming more difficult as peaks become flatter, and a shifting regulatory environment has put its viability as an option at risk.

Resource capacity accreditation is undergoing significant changes as RTOs continue to overhaul the frameworks in place that compensate resources and send price signals to incentivize new development[6]. Capacity accreditation is the percentage of a resource's nameplate capacity that is deemed reliable to perform in emergencies and is updated yearly,

[5] https://docs.nrel.gov/docs/fy19osti/74426.pdf
[6] https://www.utilitydive.com/news/ferc-pjm-capacity-accreditation-reforms-grid-reliability/706276/

before RTOs conduct capacity auctions. The accreditation outlook in the two RTOs in which IMEA operates – PJM and MISO – is mixed.

The methodology for accrediting a resource in both RTOs has transformed in recent years to shift from accrediting a resource based on its ability to contribute to reliability at times of peak energy demand, to accrediting a resource based on its ability to contribute to reliability at times of peak reliability risk[7]. While the former has historically also been the latter, the transition from dispatchable to intermittent resources has caused the divergence seen today, because intermittent resources are incapable of generation during certain conditions which may coincide with periods of high energy demand, such as a hot summer evening after the sun has set.

Future capacity accreditation forecasts from PJM predict that intermittent and storage resources will experience significant accreditation deterioration over the next decade[8]. In MISO, similar forecasts do not predict as pronounced a decline in accreditation as in PJM[9]. Nonetheless, the concept that system reliability risk increases along with intermittent generation penetration is fundamental to each RTO accreditation methodology. As such, accreditation risk is a meaningful factor to be taken into consideration in modeling revenue throughout the lifecycle of BESS.

Recommendation

BESS as it stands today is a maturing technology poised to continue to grow across the country, and it can help play a critical part in safeguarding grid reliability due to its unique capability to inject energy during times of system need and store energy during times of system surplus. Increased demand for BESS in recent years has induced technological advancements, safety improvements, and price decreases[10].

While there are several experimental BESS technologies under development that could lower the risk of thermal runaway, reduce dependency on unpredictable supply chains, and enjoy more favorable operational characteristics, lithium-ion batteries are overwhelmingly the primary technology utilized today. Lithium-ion batteries operate with relatively high efficiency and dependability as compared to other types of commercially available batteries, along with lower costs due to scale achieved through usage in other applications, such as electric vehicles and consumer electronics.

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[7] https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/elcc-measures-capacity-contribution-of-renewable-and-storage-resources.pdf
[8] https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.ashx
[9] https://cdn.misoenergy.org/PY%2025-26%20Indicative%20DLOL%20Results657893.pdf
[10] https://docs.nrel.gov/docs/fy19osti/74426.pdf

Nonetheless, this study shows that expected costs of a lithium-ion BESS could be greater than expected revenues. A phased approach towards integrating BESS into IMEA's portfolio, beginning with a behind-the-meter lithium-ion pilot project between 1-5 Megawatt (MW), configured for 4-hour duration via an offtake agreement, would allow IMEA to gain valuable contractual and operational experience working with a resource that could see significant growth across the country. Cognizant of the uncertainties that exist today surrounding the future of BESS, such an implementation strategy would also serve to limit the Agency's initial investment and corresponding risk.

Going forward, as technologies evolve, economics improve, and BESS achieve widespread adoption, IMEA will further consider larger, more complex systems. In the meantime, IMEA will also continue to seek grid-connected projects with developers and bring leading contenders to the Board for consideration.

A member Request-For-Proposal (RFP) process will be conducted to allow interested members to propose locations within their distribution systems to host an IMEA-sponsored BESS. Staff will recommend top sites, preferably with at least one site in PJM and one in MISO, for the Board's approval. Then, a developer RFP will be utilized to seek the right counterparty to build, own and operate the BESS.

BESS Feasibility Study

Chapter 1 Introduction

1.1 Impetus/Purpose for Study

The IMEA Board of Directors, via its Sustainability Plan, directed staff to study the feasibility of adding a utility-scale, behind-the-meter BESS to its resource portfolio. This directive stems from both immediate and long-term pressures on the bulk electric system.

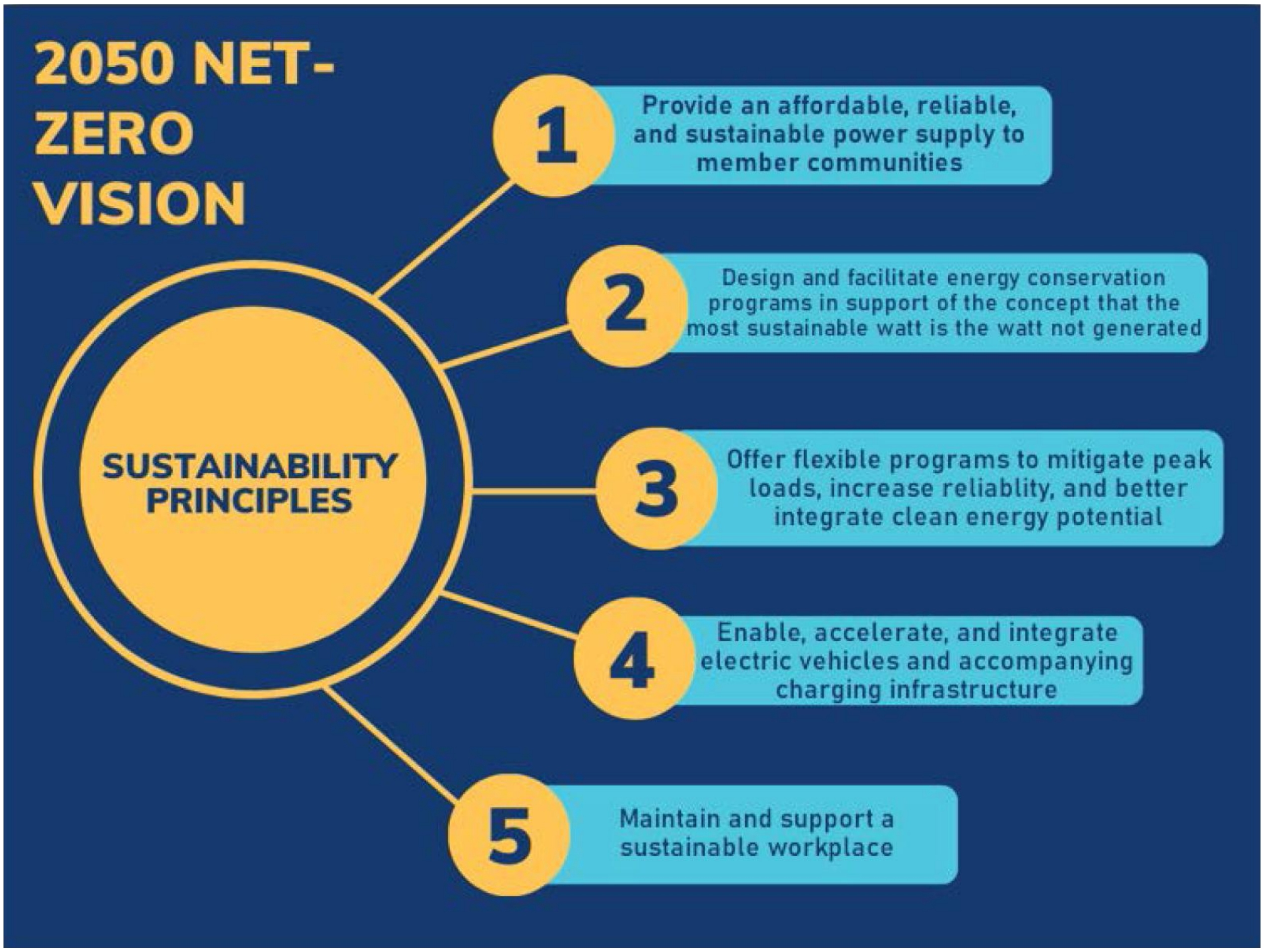
On the supply side, the retirement of dispatchable generators is accelerating. On the demand side, electrification, an ongoing proliferation in data centers, and reindustrialization are rapidly increasing energy demand. At the same time, IMEA has committed to integrating more carbon-free generation, with more than 175 MW of utility-scale solar already contracted for delivery by 2027, in addition to the 120 MW of wind generation resources that are already part of IMEA. While these additions advance sustainability goals, they also increase reliance on resources that are inherently weather-dependent. Illinois and RTO policy landscape adds further complexity to resource planning.

The state's Clean Energy and Jobs Act (CEJA), enacted in 2021, set binding requirements on the reduction of carbon emissions[11]. IMEA, through its 2050 Net-Zero Vision, is working towards those requirements. As IMEA progresses towards this net-zero environment, BESS appears to be a potentially helpful tool in providing members with affordable, reliable, and sustainable energy. Almost 10 years ago, IMEA entered into an agreement with a developer for a BESS in St. Charles. However, because of the inability of the developer to obtain financing, in part because of the nascency of the technology at the time and the speculative nature of BESS revenues, development of that project did not come to fruition. Much has changed with BESS technology in recent years, and this study provides the IMEA Board with foundational information necessary to inform decisions concerning the Agency's energy portfolio today, and into the future.

Recognizing the intersecting challenges posed by demand growth across the country, an evolving resource fleet, and an everchanging regulatory environment, IMEA's Sustainability Plan calls for a comprehensive evaluation of BESS, with implementation no later than 2030, if it is found to be economically feasible. The purpose of this study, therefore, is twofold: (1) to provide IMEA's members with a clear understanding of what BESS is and how it functions

[11] https://epa.illinois.gov/content/dam/soi/en/web/epa/topics/ceja/documents/102-0662.pdf

within today's grid, and (2) to assess whether BESS is a prudent and beneficial step for IMEA at this time.



IMEA'S 2050 Net-Zero Vision

1.2 Topics/Goals

This study is designed to give the IMEA Board and member communities the technical, financial, and operational context necessary to evaluate BESS as a utility-scale resource. Specifically, it addresses:

- Fundamentals of BESS technologies
    - An overview of how batteries work, with an emphasis on lithium-ion systems that dominate today's BESS ecosystem, while also examining emerging alternatives, such as vanadium redox flow, iron air, and solid-state chemistries that may play a larger role in future systems.

- Safety considerations
    - A discussion of key risks, including thermal runaway and resulting toxic emissions, as well as the mitigation strategies available today, from advanced fire suppression systems to detailed coordination with local first responders. This continues to be a critical element in all lithium-ion storage projects.
- Cost/Benefit analysis
    - A review of capital and operating costs, efficiency and degradation profiles, and market opportunities including ancillary services, energy arbitrage, load netting, ancillary services, and capacity accreditation. This section also discusses ownership models such as IMEA-owned versus third-party Energy Storage Service Agreements (ESSAs) and potential hybrid arrangements. GDS Associates also provided an independent analysis of their findings, and the entire report is available in the appendix.
- Strategic alignment with IMEA's mission
    - How BESS fits into IMEA's Sustainability Plan and supports its mission of providing reliable, affordable, and sustainable power. This includes compliance with state policy such as CEJA, recent developments in federal policy, resilience in the face of dispatchable resource retirements, and the ability to integrate new technologies into its portfolio.

1.3 Recommendation

The study focuses on a utility-scale, behind-the-meter BESS between 1 and 5 MW in size, located within IMEA's member distribution systems as the most practical entry point for IMEA into energy storage. While the primary goal is to gain foundational operational experience in BESS while limiting exposure, a utility-scale project would be large enough to provide additional meaningful benefits such as potential network transmission savings, capacity accreditation hedging, and energy arbitrage revenues.

Industry convention for utility-scale installations is to utilize a lithium-ion, 4-hour duration battery[12]. Selecting this size and chemistry reflects a deliberate approach to align IMEA's efforts with where BESS is today. For IMEA's member municipalities, a utility-scale installation strikes a balance between being visible and impactful at the community level, but not so large that it requires major infrastructure overhauls or exposes members to outsized capital and future supply commitments.

[12] https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf

A pilot approach offers an opportunity for IMEA, local officials, and first responders to acquire valuable experience in dealing with BESS. IMEA staff, working with local officials, will gain knowledge in BESS-related zoning best practices, and first responders will have the opportunity to refine safety and emergency protocols. If successful, lessons learned from this project will be scaled to larger and longer-duration systems over time, better positioning IMEA to meet member needs for years to come.

Chapter 2 Fundamentals of BESS Technologies

2.1 Introduction

The purpose of this section is to provide a clear, accessible overview of BESS technologies, beginning with what they are, how they work, and why they matter for IMEA. While there are many different types of batteries under development, only a small subset has achieved extensive commercial deployment. For IMEA and its member municipalities, understanding the relative strengths, weaknesses, and market prevalence of each technology is essential to making informed decisions. This chapter first outlines battery types, then explores how the predominant battery type, lithium-ion, functions, and concludes with the major trends shaping how BESS is being deployed across the United States.

2.2 Types of BESS

2.2.1 Zinc-based

Zinc-based batteries offer advantages in material availability, safety, and scalability. They are non-flammable and use abundant materials. However, they currently have lower Round Trip Efficiencies (RTE) and reduced cycle life compared to lithium-ion batteries. Zinc-based batteries are still emerging in the commercial market, with most deployments in experimental long-duration projects[13] [14].

2.2.2 Lead-acid

Lead-acid batteries are the oldest rechargeable storage technology, used for decades in backup power and industrial applications. Their low upfront cost and familiarity make them reliable in niche contexts, but they are limited by lower cyclability and reduced efficiency directly correlated to depth of discharge. As a result, their role in modern grid-scale projects is small compared to newer chemistries, but they remain an option for short-duration backup systems[15].

2.2.3 Vanadium Redox Flow

Vanadium Redox Flow Batteries provide scalable, long-duration storage by storing energy in external liquid electrolytes. They are notable for long cycle life and minimal degradation, making them promising for applications requiring daily cycling over decades, such as utility-scale energy storage. Their main drawbacks are high upfront costs and lower efficiency

[13] https://www.azom.com/article.aspx?ArticleID=23717
[14] https://flarecompare.com/Energy%20Storage%20Technology/Zinc-Air%20Batteries%20vs.%20Lithium-Ion%20Batteries%20for%20Energy%20Storage/
[15] https://energystorageeurope.eu/wp-content/uploads/2016/07/EASE_TD_Electrochemical_LeadAcid.pdf

compared to lithium-ion. Still, they represent one of the leading candidates for long-duration storage[16].

2.2.4 Solid-state

Solid-state batteries replace the semi-liquid electrolyte of lithium-ion with a solid medium. This design does not involve a flammable electrolyte and also allows for potentially higher energy density as compared to lithium-ion. While not widely commercially available, they are among the most highly anticipated emerging technologies due to investment from carmakers and storage developers. Utility-scale deployments of solid-state batteries are expected at some point in the 2030s[17].

2.2.5 Iron Air Batteries

As part of a potential federal grant, IMEA staff previously explored Iron Air batteries. This type of battery operates via a principle called reversible rusting. The charging cycle involves running an electric current that converts rust to iron, expelling oxygen. Upon discharging, iron air batteries absorb oxygen, and convert iron metal back to rust. The resulting reaction releases energy. While input resources – iron and air – are abundant and low-cost, iron air batteries are slower to charge and not as efficient as other forms of batteries[18] [19] [20].

2.2.6 Lithium-ion

Lithium-ion batteries dominate the global storage market, accounting for nearly 90% of new U.S. grid-scale battery capacity today[21]. This is because of their high energy density, fast response times, and round-trip efficiencies in the range of 85–90%[22]. They can be deployed at nearly any scale and have become the status quo for utility-scale BESS.

In recent years, lithium-ion battery safety has advanced substantially, with containerized enclosures now incorporating gas detection, fire suppression, and remote monitoring systems to mitigate the risks of thermal runaway. Cell costs have declined nearly 90% in the past decade[23], which in turn has made projects more financially viable. These attributes mean that lithium-ion systems have an established pathway to commercial operation, giving them a clear advantage over emerging chemistries like solid-state or vanadium redox flow.

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[16] https://www.sciencedirect.com/topics/engineering/vanadium-redox-flow-battery#:~:text=A%20vanadium%20redox%20flow%20battery,and%20conversion%20without%20cross%2D contamination.
[17] https://www.sciencedirect.com/science/article/pii/S0306261925002764
[18] https://evolutionoftheprogress.com/iron-air-batteries/#Iron-Air_Battery_Advantages
[19] https://oilprice.com/Energy/Energy-General/How-Iron-Air-Batteries-Could-Dethrone-Lithium.html
[20] https://formenergy.com/technology/battery-technology/
[21] https://www.spglobal.com/commodity-insights/en/news-research/latest-news/metals/042524-new-global-battery-energy-storage-systems-capacity-doubles-in-2023-iea-says
[22] https://atb.nrel.gov/electricity/2024/utility-scale_battery_storage
[23] https://www.iea.org/reports/batteries-and-secure-energy-transitions/executive-summary

Until an alternative becomes widely commercially available, lithium-ion will likely remain the most economic and widely supported type of BESS.

2.2.6.1 Chemistry

To understand why lithium-ion is the leading technology in BESS, it is important to review how the technology works. Each lithium-ion cell consists of four essential components:

- Cathode: The positive electrode, typically made from a lithium metal oxide such as lithium-nickel-manganese-cobalt-oxide (LNMC) or lithium iron-phosphate (LFP). The cathode determines much of the battery's energy density, voltage, and cyclability.
- Anode: The negative electrode, usually composed of graphite. During charging, lithium ions move from the cathode and into the anode. Advances in anode materials, such as silicon blends, are being researched as a means to potentially boost storage capacity.
- Electrolyte: A lithium salt dissolved in a solvent. The electrolyte serves as the medium through which lithium ions shuttle between electrodes during charging and discharging.
- Separator: A thin, porous membrane that physically separates the anode and cathode, allowing ion transport while preventing short circuits.

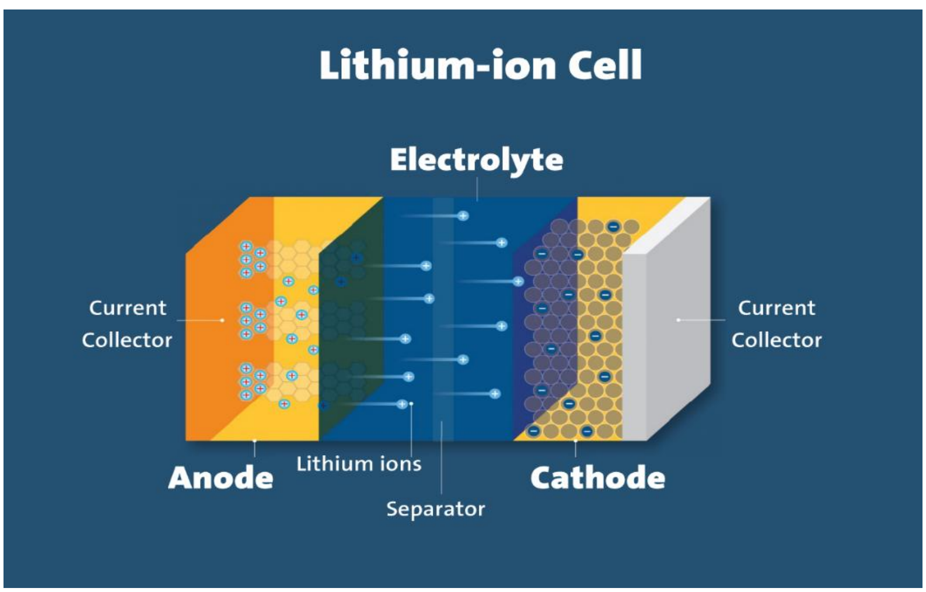

Image source: https://ul.org/research-updates/what-are-lithium-ion-batteries/

The operation of a lithium-ion cell relies on the reversible movement of lithium ions. During charging, an external current forces lithium ions to move from the cathode, through the electrolyte and separator, and into the anode where they are stored. When the battery discharges, the process reverses: lithium ions leave the anode and return to the cathode, releasing stored energy as electrons flow through the external circuit[24].

This mechanism gives lithium-ion batteries their high efficiency and cycle life. However, it also presents challenges. The electrolyte is flammable, and if cells overheat or are damaged, uncontrolled reactions can lead to thermal runaway. Degradation over thousands of cycles also reduces capacity over time. Manufacturers mitigate these issues through battery management systems, thermal controls and oversizing[25].

For BESS, lithium-ion's flexibility allows for thousands of cells to be combined into modules, racks and containerized systems. This scalability, coupled with extensive manufacturer experience, underpins its role as the cornerstone of today's BESS market.

2.3 Trends in BESS

2.3.1 Duration

The duration of a BESS refers to how long it can discharge at its rated power before depleting its stored energy. In the United States, the current duration market standard for utility-scale projects is four hours, largely because this has aligned with morning and evening peak demand in most RTOs and because lithium-ion chemistries are cost-optimized at this length. However, demand for longer-duration storage is increasing. Utilities in California, for instance, have begun procuring resources with 8+ hours of discharge to cover periods of low solar output during the day and after sunset[26].

Emerging chemistries such as vanadium redox flow and solid-state systems are explicitly targeting these long-duration applications. For IMEA, taking costs into account, a 4-hour battery is most practical today. Nonetheless, planning for longer-duration technologies will be important as intermittent generation prevalence deepens and accreditation standards evolve.

2.3.2 Standalone or Hybrid

BESS can be configured as standalone systems or as hybrids paired with generation. A standalone system requires less space, making it ideal for more densely populated

[24] https://letstalkscience.ca/educational-resources/stem-explained/how-does-a-lithium-ion-battery-work
[25] https://www.sciencedirect.com/topics/chemistry/lithium-ion-battery#:~:text=Lithium%2Dion%20batteries%20are%20defined,as%20thermal%20runaway%20and%20fire.
[26] https://www.caiso.com/documents/2024-special-report-on-battery-storage-may-29-2025.pdf

locations. Hybrid projects, such as solar-plus-storage, are a growing segment of the U.S. market largely due to interconnection advantages through an RTO. In hybrid designs, the battery can charge directly from the solar facility or from the grid, taking advantage of excess solar output that would otherwise be sold into the market at low or even negative prices and discharge during the high-value evening peak when solar electricity generation is no longer available. This configuration improves the economics of both assets. The solar plant's output can take better advantage of real-time energy price volatility that can fluctuate every five minutes. The BESS benefits from a dedicated charging source, eases congestion, and allows both projects to share costs.

2.3.3 Behind-the-Meter or Grid-Connected

BESS can be deployed either Behind-the-Meter or as a grid-connected system. Behind-the-meter projects are often less than 5 MW, sited within communities, and can provide reliability benefits to critical load in addition to market revenues. Behind-the-meter BESS connected at the distribution level may also reduce transmission charges by netting peak demand and reducing a Load Serving Entity's (LSE) capacity requirement. For this study, our focus will be on BTM projects connected at the distribution level in an IMEA member community.

Grid-connected systems, by contrast, are typically greater than 25 MW and located at large substations or high-voltage interconnections, where they can absorb and inject greater amounts of energy. Grid-connected systems are subjected to penalties for non-performance as well as additional RTO Tariff charges during the charging period. However, a major barrier to grid-connected BESS deployment in both MISO and PJM has been the lengthy interconnection queue process along with additional requirements imposed by the RTOs.

Developers seeking to connect to the transmission system must undergo extensive system impact studies, which has led to years-long backlogs and projects waiting five years or more before receiving RTO approval. In MISO, the queue has at points grown to more than 300 Gigawatt (GW) of proposed projects[27], while PJM's queue has exceeded 250 GW in recent years, with storage and renewables making up the majority[28].

Much of this backlog can be attributed to the fact that non-dispatchable solar and wind resources have significantly lower capacity factors than a baseload thermal unit. It takes

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[27] https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/022525-miso-on-path-to-reduce-queue-process-to-one-year-with-reforms-technology-executive#:~:text=The%20grid%20operator%20is%20collaborating,25.

[28] https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/interconnection-reform-progress-fact-sheet.pdf

considerably more nameplate capacity from solar (~25% capacity factor) and wind (~35% capacity factor) to equal the amount of energy a baseload thermal unit could generate with a capacity factor between 80-90%. Solely on an energy basis, one might need 240-340 MW of nameplate wind or solar to equal the output of a 100 MW nameplate baseload thermal plant. This requires the RTOs to study many more individual projects spread out electrically and geographically over the grid requiring significant upgrades. In addition, renewable developers are financially risk-averse and, as a result, seek offtake agreements to mitigate loss in revenue from the RTOs.

These delays have significant impacts. For example, projects may not achieve commercial operation on schedule, making it difficult for developers and utilities to plan resource adequacy, hedge costs, or meet policy targets. The longer it takes to get through the queue, the longer a developer has to wait to build its project. Interconnection costs can fluctuate until the queue process has completed and the cost of the required upgrades are finalized, which makes it difficult for developers to competitively price their projects.

Both MISO and PJM have initiated reforms to address the backlog. PJM adopted a cluster study approach in 2023[29], grouping projects together by study cycle and requiring more stringent readiness milestones, such as site control and financial commitments, before a project may enter the queue. MISO has pursued similar queue reforms[30]. Some of the RTO reforms require developers to place higher deposits earlier in the process to keep their place in the queue, and this requires developers to invest additional upfront capital and to find committed offtakers earlier in the process to justify continued investment in the project.

IMEA will continue to seek potential grid-connected BESS. In the interim, the logical first step into BESS would be a behind-the-meter pilot project connected to our members' distribution systems to limit the Agency's risk and responsibility for our introduction to this new resource into our portfolio.

2.3.4 Growth of BESS, Now and Projected

2.3.4.1 National

Battery deployment in the United States has grown at a rapid pace. In 2020, less than 2 GW of utility-scale storage was operating nationwide; by 2025, that figure exceeds 25 GW[31] [32]. California hosts more BESS than any other state[33]. California also has the highest electricity

[29] https://www.utilitydive.com/news/ferc-pjm-grid-interconnection-queue-christie/754050/
[30] https://www.utilitydive.com/news/ferc-miso-interconnection-queue-cap/739002/
[31] https://www.eia.gov/todayinenergy/detail.php?id=54939
[32] https://www.eia.gov/todayinenergy/detail.php?id=64705
[33] https://www.ctrmcenter.com/blog/industry-news/us-states-ranked-by-installed-battery-capacity/

prices in the country, save for Hawaii[34], at 2-3x the Illinois' average. These high market prices improves the economics of adding batteries.

Much of the BESS growth in Texas — which follows California in terms of total BESS — can be attributed to its unique grid and the state's ideal conditions for both wind and solar projects. The Electric Reliability Council of Texas (ERCOT) does not cross state boundaries, so it is largely exempt from federal oversight. ERCOT has significantly fewer regulatory approvals, allowing projects to interconnect much faster than in other RTOs. ERCOT also does not have a capacity market component, putting increased pressure on electricity prices to send market signals and providing batteries significantly more potential energy arbitrage revenues. The sizeable wind and solar additions in ERCOT increase energy arbitrage for BESS as energy prices in ERCOT can be very volatile and fluctuate drastically based on the substantial amount of intermittent wind and solar output.

The U.S. Energy Information Administration (EIA) projects that storage capacity could surpass 60 GW by the end of 2026[35], driven by federal incentives, state mandates, and declining technology costs. Most of this buildout is expected to be lithium-ion, but long-duration chemistries are forecasted to gain market share in the 2030s. For context, MISO has more than 2 GW of storage projects in its interconnection queue today, while PJM has more than 15 GW, signaling strong developer interest. These trends underscore the fact that BESS is moving rapidly from a limited technology to a mainstream resource.

2.3.4.2 Illinois

Battery deployment in Illinois and the Midwest has been relatively minimal compared to other regions of the country. In the PJM portion of Illinois, there is a total of ~100 MW of BESS.[36] In MISO's portion of Illinois, barring some pilots, there is no BESS. A negligible amount of BESS capacity cleared in the latest auctions, both in PJM and MISO respectively[37] [38]. With the passage of the Clean and Reliable Grid Affordability Act (CRGA), it is anticipated that Illinois will begin to substantially ramp up battery procurement.

[34] https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
[35] https://www.utilitydive.com/news/us-utility-scale-energy-storage-to-double-reach-65-gw-by-2027-eia/750338/
[36] https://www.eia.gov/electricity/data/eia860m/
[37] https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf
[38] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

Chapter 3 Safety Considerations

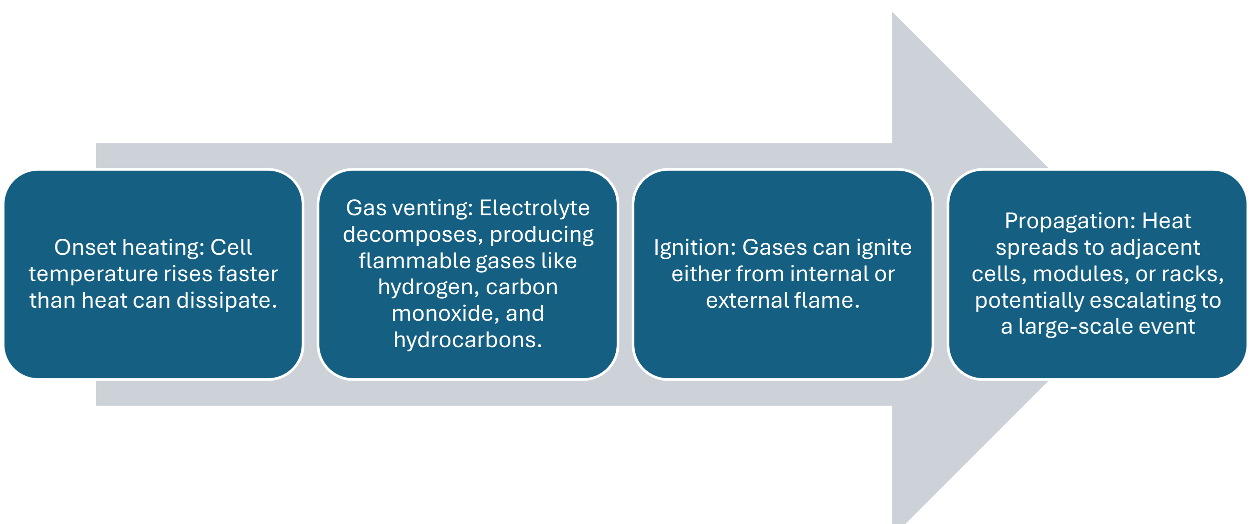
3.1 Introduction

Safety is the most critical dimension of lithium-ion BESS. High-energy lithium-ion cells can fail catastrophically under certain conditions, leading to thermal runaway, fire, toxic emissions, and residual hazards that require specialized mitigation. There have been several large, widely reported fires at BESS facilities. Some, such as the January 2025 Moss Landing Fire in Monterey County, California, were at older facilities that lacked modern mitigation technologies and protocols[39]. Nonetheless, fire risk is meaningful. As more BESS has come online, best practices have become more informed. At present, national codes and standards for BESS exist across every stage of development.

This chapter outlines the safety considerations for utility-scale BESS, beginning with thermal runaway. It then addresses toxic emissions, followed by mitigation strategies, and concludes with the importance of local coordination. The study draws from national standards such as NFPA 855, IFC 2021, the DOE Energy Storage Handbook, and lessons learned from recent incidents and studies.

3.2 Thermal Runaway

Thermal runaway is the defining hazard of lithium-ion BESS. It occurs when a cell's internal temperature rises uncontrollably, usually from one of four triggers: mechanical damage, electrical abuse, thermal stress, or manufacturing defects. Once initiated, the process unfolds in several stages:



[39] https://fsri.org/news/moss-landing-battery-fire-hit-plant-older-vulnerable-technology

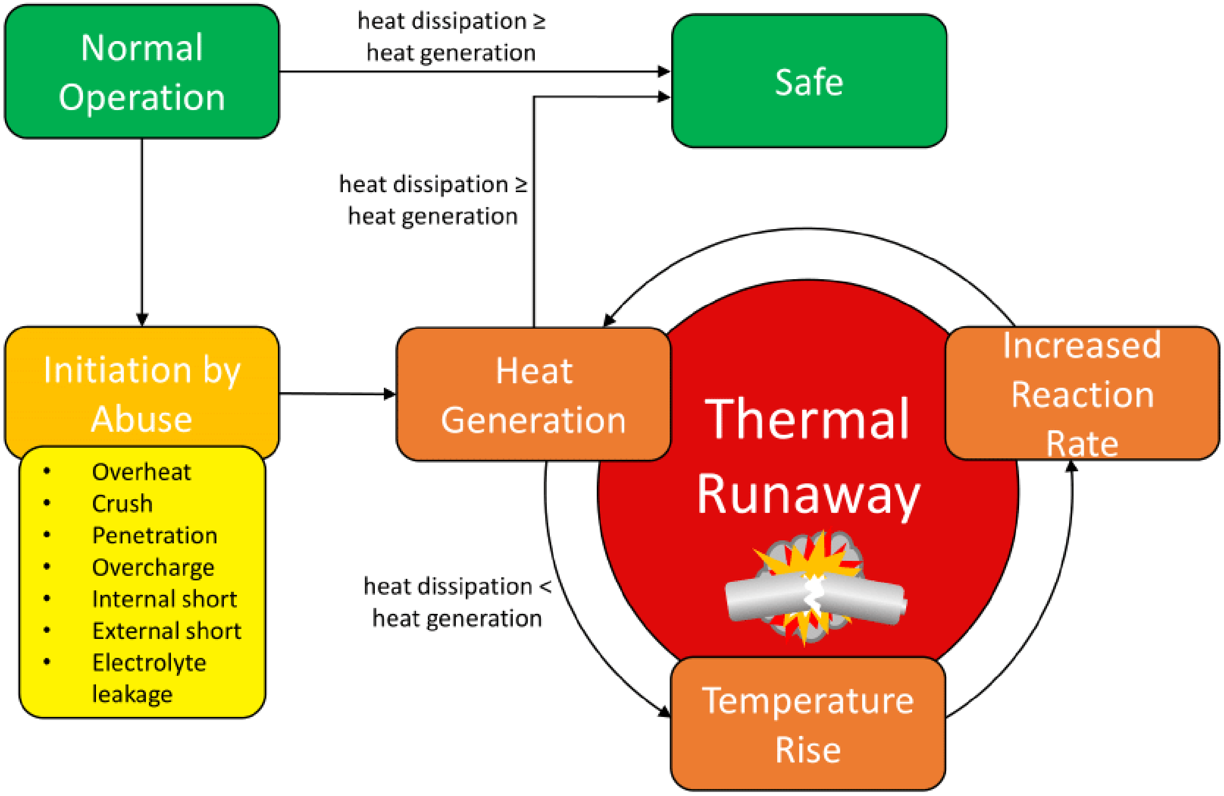


Image Source: https://www.researchgate.net/figure/Thermal-runaway-process-within-a-single-cell_fig1_341562984

Propagation is the most dangerous step in the reaction. A single failed cell may be somewhat inconsequential, but the cascading effect across a tightly packed module of cells can overwhelm suppression systems. Firefighters often cannot access the ignition source directly because it is buried inside sealed containers. This creates smoldering, difficult to extinguish, deep-seated fires, along with the danger of stranded energy, which is the residual charge in unaffected cells.

While research into advanced thermal runaway prevention and mitigation techniques is ongoing, the status quo today dictates that, even with advanced suppression systems, monitoring and containment are often the only effective strategies until the event has run its course. Fires may also reignite hours or even days later, further complicating matters.

3.3 Toxic Emissions

During thermal runaway, lithium-ion batteries release gases including hydrogen, carbon monoxide, hydrogen fluoride, hydrogen cyanide, and hydrochloric acid. Even at low concentrations, hydrogen fluoride is particularly hazardous and has been a central focus in both thermal runaway modeling and response planning. The quantity and composition of emissions vary by chemistry, system size, and fire progression. For this reason, EPA and NFPA do not define a universal "safe" threshold; instead, they recommend modeling and real-time monitoring to guide emergency response.

American Clean Power's (ACP) report titled *Assessment of Potential Impacts of Fires at BESS Facilities* states that "data from real-world incidents, experimental studies, and environmental monitoring efforts indicate that BESS fires have a minimal long-term environmental impact compared to other large industrial and structural fires," ACP's report also states that "studies indicate that emissions are largely confined to the immediate vicinity of the fire, with rapid dissipation and concentration reduction in open-air scenarios."[40]

Post-incident cleanup extends beyond extinguishment, which itself may take days or weeks to achieve. Water runoff can carry heavy metals, fluorinated compounds, and other toxic byproducts. EPA guidance requires containment of this runoff, proper hazardous waste packaging of damaged cells or modules, and disposal in line with federal and state regulations.

3.4 Mitigation Strategies

Mitigation is best understood as a layered approach, combining design, technology, and regulatory standards.

3.4.1 Technological Advancements

- Early detection: Remote sensors, including infrared and thermal cameras, can identify abnormal heating or gas release before runaway occurs.
- Containment and spacing: Industry standards promote rack separation, fire-rated enclosures, and deflagration venting that prevent cell failures from escalating to site-wide events.
- Suppression systems: Systems now integrate both endogenous (within the container) and exogenous (site-wide) suppression technologies. Examples include clean-agent flooding, water mist, and aerosols, often used in parallel with firewalls.

3.4.2 Safety Codes & Regulatory Standards

- DOE Energy Storage Handbook: Consolidates best practices and case studies, serving as a technical reference for utilities and regulators.

[40] https://cleanpower.org/wp-content/uploads/gateway/2025/03/Assessment-of-Potential-Impacts-of-Fires-at-BESS-Facilities.pdf

- International Fire Code (2021, Chapter 12): Mandates hazard mitigation analyses, ventilation, detection, and emergency planning for BESS.
- NFPA 855: Establishes siting, installation, and emergency response requirements; paired with NFPA's fact sheets, it is now one of the most widely adopted BESS safety standards.
- EPA Guidance: Recommends isolation zones, runoff containment, and full Personal Protective Equipment for first responders.
- Local/State Initiatives: Demonstrate how intergovernmental coordination streamlines safe deployment and permitting.

Together, these measures enhance overall BESS safety through a multi-faceted approach. Fire and associated risks are kept top of mind throughout the development of both the technology and corresponding regulations to create a comprehensive framework in which BESS can operate.

3.5 Local Coordination

Even with thorough design and regulation, the issue of safety boils down to local preparedness. Standards set at the local and national level will dictate effective response in the case of a BESS-related fire.

- Community Engagement: Outreach to stakeholders builds trust and ensures transparency around modeling, emergency plans, and site inspections. California's San Diego County, a well-established location for BESS, requires pre-fire plans and public review for all new BESS sites.
- Permitting and Siting: Local zoning ordinances should align with NFPA 855 and IFC 2021, incorporating setbacks, site access for firefighting, and hazardous materials storage controls.
- First Responder Training: IAFC and EPA stress that firefighters need specific training on BESS hazards such as thermal runaway, stranded energy, toxic emissions, and defensive suppression tactics. Training should combine manufacturer-supplied protocols with NFPA materials.
- Manufacturer Guidelines: BESS developers provide site-specific operation and management manuals that must be shared with local officials. NFPA 855 requires these documents as part of commissioning to ensure that responders have access to detailed instructions.
- Suppression Readiness: Sites should be equipped with both internal and external suppression systems. Suppression systems can range from thermal sensors, battery

management systems, batteries with adequate compartmentalization to prevent proliferation, and proper ventilation and exhaust controls. Local fire departments must understand the proper protocols in suppressing and extinguishing BESS fires

The adequacy of local electric infrastructure and the preparation of member municipalities is crucial to the successful implementation of a utility-scale BESS. Any project, however modest in scale, will require careful coordination between IMEA, developers, and members to achieve reliable long-term operations.

Electrical Infrastructure Upgrades

Before a site can host a BESS, a detailed engineering assessment must be conducted in preparation. Upgrades may include installation of new switchgears, isolation breakers, or secondary relays, as well as Supervisory Control And Data Acquisition (SCADA) systems to allow for monitoring and control. In some cases, communication upgrades may also be necessary to integrate the system into IMEA's operational network and ensure compliance with cybersecurity standards.

Local Infrastructure Support

The host municipality will play a critical role in facilitating site readiness. This includes providing land, ensuring access for equipment during construction, and verifying compliance with local zoning and permitting requirements. Coordination with public works and building departments will be important for grading, drainage, and utility routing. Additionally, municipalities can help streamline local approvals by establishing clear permitting pathways for BESS, which remain relatively new or nonexistent in many jurisdictions. Of the Illinois counties in which IMEA member communities are located, only LaSalle, Randolph, and Champaign counties currently host BESS. Of those, only LaSalle County has zoning and permitting ordinances. Champaign County is in the process of formalizing language. Zoning and permitting set at the municipality level would supersede any zoning and permitting set at the county level.

First Responder Training and Safety Preparedness

Equipping local fire and emergency services with proper training is essential for safety. Prior to a project's Commercial Operation Date (COD), IMEA, the developer and host member should coordinate with local fire departments and emergency response officials to conduct site-specific training covering lithium-ion hazards, thermal runaway scenarios, gas venting, and recommended response protocols. Resources from the National Fire Protection Association (NFPA 855), Sandia National Laboratories, and the Department of Energy exist to guide this process. Emergency access routes, fire suppression systems, and signage should all be developed in collaboration with first responders to ensure readiness under any circumstance.

Ongoing Coordination

Beyond initial development, regular communication between IMEA operations staff, local utility personnel, and first responders will be key to maintaining safety and reliability. Joint training, annual inspections, and continuous reviews of emergency response plans should become part of the project's ongoing management.

Summary

Thermal runaway and its consequences, such as deep-seated fires, toxic emissions, and stranded energy are the central safety risks of lithium-ion BESS. Effective mitigation requires a multilayered defense of technology, codes, and local coordination. National standards such as NFPA 855[41] and IFC 2021[42] provide the framework, but the decisive element is how IMEA and its member municipalities integrate those requirements with local permitting, training, and emergency planning. By embedding safety at every level, IMEA can pursue BESS deployment confidently, ensuring that risks are not only understood but actively managed.

Considering that lithium-ion is the predominant BESS technology on the market today, and that extensive knowledge exists on fire prevention and mitigation, IMEA believes it to be the chemistry that provides the best balance between cost-effectiveness, safety, and energy efficiency at this time. Taking a phased approach allows IMEA to gain expertise in BESS while remaining able to take advantage of potential further technological advancements, not only for lithium-ion batteries, but also for other technologies that may mature and become more cost-effective in the future.

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[41] https://www.nfpa.org/codes-and-standards/nfpa-855-standard-development/855
[42] https://codes.iccsafe.org/content/IFC2021P2

Chapter 4 Cost and Benefit Analysis

4.1 Introduction

BESS prevalence has continued to increase as the cost of batteries has decreased. In addition to decreasing prices, BESS technology has also continued to improve, further enhancing their efficiency and safety[43]. Carbon-free goals from businesses and electric providers or Renewable Portfolio Standards (RPS) set by individual states are also driving the growth of BESS. Industry trends of replacing aging dispatchable resources with intermittent resources are propelling BESS to become a tool to support the grid between times of energy excess and scarcity. This chapter will address the primary drivers of BESS costs, discuss owning versus contracting BESS, explain the financial and operational benefits of BESS, and, finally, provide economic evaluations of sample BESS. This chapter also includes staff findings, as well as GDS Associates' independent findings.

4.2 Costs

The cost of a BESS extends beyond the cost of the batteries. This section will discuss the costs of siting, building, operating, maintaining, and decommissioning a BESS. It will also discuss two of the primary drivers of the cost of batteries -- tax credits and tariffs -- as well as legislation that is affecting demand. Lastly, an explanation of how the pricing of battery off-take agreements are structured will be provided.

4.2.1 Siting

4.2.1.1 Behind-the-Meter BESS

Only after determining the desired project location can the project size be finalized. Location is an extremely important factor in the decision. Not only does location have a significant impact on a project's financial and operational benefits, but the significant potential fluctuations in locational costs can make or break potential project economics.

In its prior behind-the-meter solar projects, IMEA asked its members to propose the best locations within their distribution systems and donate the use of the land to the project to scout locations more efficiently. This eliminates the cost of purchasing or leasing the land and lessens the cost of interconnection upgrades. Siting a project within a member's distribution system could offer advantages which are not possible through a grid-connected system.

Generally, the most cost-effective place to locate BESS, or any utility-scale resource, is as close to a substation as possible. Proximity to a substation reduces the cost of

[43] https://cleanpower.org/news/battery-storage-industry-unveils-national-blueprint-for-safety/

interconnection, while increasing grid stability and reliability. There are downsides, though. For example, the fire risks posed by lithium-ion batteries could jeopardize additional infrastructure if placed too close to a substation, leading to collateral damage. Lithium-ion batteries require space, which might be limited within a substation, for excess heat to dissipate. A BESS will also require normal maintenance. Placing a BESS within the restricted access of a substation increases the safety risks for those that may not be as familiar with substation protocols. It would also increase the demands on first responders if a safety hazard from a BESS cannot be contained.

Beyond the concerns surrounding substations, the condition of the distribution system and its ability to handle the injections and withdrawals of an energy storage system can also meaningfully influence the cost of the required upgrades to interconnect BESS. Proposed sites would first be evaluated based on the suitability of the land and the electric infrastructure required to handle the proposed project. Once a number of finalists are selected, the next step would be to perform an Interconnection Study for each finalist location to determine the estimated cost of upgrades required to interconnect the proposed project to the member's distribution system.

4.2.1.2 Grid-Connected BESS

In order for a BESS to connect to either the MISO or PJM grid, it must enter into the respective RTO's interconnection queue process before receiving a Generator Interconnection Agreement (GIA), a process which can last years. Developers normally perform a preliminary site analysis, obtain site control, and receive basic land use permits to filter down the number of potential sites before entering the queue process. This can add several years to the development process even before a project is ready to enter the RTO queue.

There are numerous BESS at various stages of the MISO or PJM queues in need of offtakers. In the past, there have been opportunities for IMEA to assume partial ownership of a large, 100 MW+ grid-connected BESS project, with the range of offers between $13/KW-Month and $17/KW-Month, largely depending on the project's nameplate capacity. IMEA will remain vigilant in monitoring the outlook of grid-connected projects, but due to the aforementioned challenges which come with choosing to site in front of the meter, staff recommend building behind-the-meter in one or more of IMEA's member communities.

4.2.2 Build, Operate & Maintain, Decommission - Project Lifecycle

Once a location has been selected and the decision to proceed with the BESS has been made, in the case of an ESSA, a developer will initiate the Engineering, Procurement, and Construction (EPC) work. The primary route to accomplishing this work is to contract an experienced EPC Contractor. Some of the larger developers might have their own departments to handle some or all of this work, but it is common for BESS owners to delegate this work out to an external group with the necessary expertise.

There are many complex matters that must be considered when building a BESS to connect it to either a distribution system or the larger transmission system. Additional site preparations, building permits, engineering design, and interconnection work must be performed to be ready to commence BESS installation. This requires significant coordination and timing amongst several different entities to get all of the necessary work finished in a timely manner.

Perhaps the most pronounced challenge, especially with the passage of the One Big Beautiful Bill Act (OBBBA) and recent tariff implementations, as well as export controls from countries that produce BESS inputs, is the procurement of the materials for a lithium-ion BESS. The OBBBA added extra restrictions and requirements concerning sourcing materials from Foreign Entities Of Concern (FEOC) in order to receive federal tax credits[44]. This is an area that carries significant risk and significant need for supply chain monitoring. As for construction, certain labor standards have to be met to qualify for the Inflation Reduction Act of 2022 (IRA) “Labor Adder” tax credits[45].

Similarly, the ongoing operation and maintenance work would also need to be assigned to a group of experienced professionals. As BESS becomes more common, developers will continue to enter the market. It will be important to ensure that the selected contractors have adequate experience to reduce downtime. Availability of the BESS to be able to charge and discharge when needed is absolutely critical to maximizing revenues.

As will be discussed in the Benefits section 4.4, the battery’s availability to reduce peaks, charge when energy prices are low and subsequently discharge when energy prices are high can significantly alter the economics of any BESS. The quality of the batteries and the ongoing operation and management of a BESS are essential determinants in the project’s potential financial success. Batteries degrade over time and through charging cycles. Replacement of individual cells is vital to keeping up maximum capabilities. Minimizing thermal runaway also requires ongoing maintenance and cell replacement.

At the end of a BESS’ useful life comes decommissioning. Considering the relative infancy of BESS technology in the electric utility industry, the maturity of the decommissioning process of such products is even more novel. The cost of decommissioning a BESS will heavily depend upon the cost of the required recycling or proper disposal of the hazardous materials in the battery technology used.

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[44] https://www.irs.gov/newsroom/one-big-beautiful-bill-provisions

[45] https://www.irs.gov/inflation-reduction-act-of-2022

4.2.3 Tax Credits

4.2.3.1 Inflation Reduction Act

The IRA greatly expanded the available tax credits for any facility that generates electricity with net-zero greenhouse gas emissions or enables the transition to a decarbonized grid. The IRA also provided additional tax credits for projects that hit certain thresholds of domestic content, were built in Energy Communities, or met certain labor standards.

The Domestic Content adder provided additional incentive to use domestic content but also allowed exemptions if using domestic materials would have significantly increased the cost of the project. The Domestic Content requirement could be met by obtaining 100% of the steel and iron used in the project from producers in the United States, and a share of the total costs of manufactured products produced in the US, which increased from 40% before 2025 to 55% for 2027 and later. There was an increased cost exception which stipulated that if using domestic content would increase the overall cost of construction by more than 25%, or if there were insufficient quantities of US made products, a project could still get the domestic content tax credit adder without meeting the requirements.

To qualify for the Energy Community adder, the project had to be located in a Superfund site, in a Census tract that includes or is adjacent to either a coal mine that closed after 1999 or a coal-fired power plant that retired after 2009. Additionally, the Census tract could be in a statistical area with high unemployment and that was heavily reliant on tax revenues related to fossil fuels. The unemployment rates are recalculated each year, therefore a project must begin construction in a year where those qualifications are met to be able to qualify for the additional tax credit.

For a project to qualify for the labor standards adder, the project had to meet certain prevailing wage and apprentice requirements. Prevailing wages must be paid during project construction and for either 5 years post construction if taking an Investment Tax Credit (ITC) or 10 years post construction if taking a Production Tax Credit (PTC). Contractors also had to utilize certain levels of registered apprentices during the project construction for the project to receive the labor standards adder.

IMEA Member communities that qualify as an Energy Community should be given preference to host an IMEA BESS considering the added tax credits available. A map of Illinois' Energy Communities is included in the Appendices. The IRA also introduced the "direct pay" option which allows tax exempt organizations to receive a direct payment from the IRS for the applicable tax credit amount instead of solely relying on a private developer to be able to take advantage of the tax incentives. Direct Pay recipients, however, face stricter domestic content requirements. Instead of being eligible for an additional credit for meeting domestic content thresholds, a tax-exempt entity's direct pay amount could get reduced to zero in later years if those standards were not met. These requirements also opened up the recipient of the tax credits to extensive record keeping responsibilities.

While the IRA's direct-pay tax credit option makes owning a BESS a possibility for IMEA, it still appears that an offtake agreement with a private BESS developer would be the most straightforward and predictable path forward for IMEA.

4.2.3.2 One Big Beautiful Bill Act

The OBBBA greatly accelerated the expiration of those tax credits for wind and solar projects, which is expected to greatly reduce the demand and economic feasibility for wind and solar projects. The tax credits for energy storage, which were largely spared in this legislation, are expected to take precedence if FEOC regulations can be mitigated. BESS can still get the full tax credit so long as construction is started before 2033. Thereafter they are eligible for 75% of the credit if the project is started in 2034 and 50% of the credit if started in 2035. There is no credit for projects starting in 2036 or later. The OBBBA also hastened the expiration date of the clean vehicle credit to September 30, 2025. This is expected to slow the demand for electric vehicles and thus slow the demand for the lithium-ion batteries that power them. This should be beneficial to the electric utility BESS industry.

The OBBBA did introduce enhanced FEOC rules limiting material assistance from a Prohibited Foreign Entity (PFE), which are companies under the control of the governments of China, North Korea, Russia or Iran, or companies linked to forced labor practices. With China currently controlling much of the raw materials used in batteries and responsible for building nearly all of the world's lithium-ion batteries, alternatives are scarce. The primary FEOC restriction of concern is that the tax credit claimant has to limit the amount of components from PFEs to still qualify for the tax credits. Another FEOC restriction is that the project cannot license critical technology from a PFE if the license agreement allows the PFE control over the facility or several other rights or benefits. Extensive supply chain oversight and record keeping will be needed to monitor one's status and prove compliance.

The table below shows the percentage of each type of component that has to come from a Non-PFE or the Material Assistance Cost Ratio calculation (MACR)[46].

Year	48E/45Y (qualified facility)	48E/45Y (energy storage)	Solar components (45X)	Wind components (45X)	Inverters (45X)	Battery components (45X)	Critical minerals (45X)
2026	40%	55%	50%	85%	50%	60%	0%
2027	45%	60%	60%	90%	55%	65%	0%
2028	50%	65%	70%	-	60%	70%	0%
2029	55%	70%	80%	-	65%	80%	0%
2030	60%	75%	85%	-	70%	85%	25%
2031	60%	75%	85%	-	70%	85%	30%
2032	60%	75%	85%	-	70%	85%	40%
After 2032	60%	75%	85%	-	70%	85%	50%

MACR = ((T-P)/T) x 100%

T= Total cost of all manufactured products

P= Total cost of all manufactured products from a PFE

4.2.4 Tariffs

On top of FEOC concerns, battery developers are also closely watching the ever-changing threat of tariffs. The Trump administration has caused considerable price uncertainty by making numerous tariff announcements since taking office at the beginning of 2025. The ever-changing environment makes it difficult for industry to plan for the future if tariffs can be announced, implemented, and subsequently renounced so rapidly.

The fact that most of the rare minerals needed for lithium-ion batteries are mined in China and that most lithium-ion batteries are currently produced in China could potentially put tremendous price pressure on all lithium-ion batteries. It will take time for the industry to diversify its supply chains and boost manufacturing in other countries.

4.3 Own v Energy Storage Service Agreement

4.3.1 Introduction

Prior to the direct pay option in the IRA, the most economical way for tax-exempt organizations to invest in a renewable energy project was to utilize an ESSA or offtake

[46] https://www.bakertilly.com/insights/understanding-foreign-entity-of-concern

agreement with a tax paying developer. Whether to own or enter into an ESSA is a major decision that requires a thorough analysis of the benefits and risks of the proposal.

4.3.2 Own

Ownership generally brings with it lower costs but also increased responsibilities and additional risk. Choosing not to utilize a developer typically lowers the cost to build and maintain a BESS by eliminating a rate of return that is needed by the developer to turn a profit. Ownership places all of the responsibility and risk associated with the asset onto the owner. If the unit malfunctions or does not perform to meet expectations or is damaged, including even partially, the owner suffers the lost revenue and will be responsible for the costs to bring the unit back to service.

In addition, IMEA would be responsible for liabilities related to safety concerns, emissions, and repairs or replacements. Those responsibilities could be mitigated via insurance policies or additional contractual relationships to spread out such responsibilities, but that still increases IMEA's workload with additional contracts and price uncertainty from those future contracts. IMEA would also have to navigate maintenance along with other major expenses such as insurance, dispatch software, and manufacturer required upgrades to the firmware on a timely basis and decommissioning the project at the end of its useful life.

4.3.3 Energy Storage Service Agreement

Entering into an offtake agreement or ESSA simplifies the process for the IMEA staff and places nearly all of the responsibilities and risk onto the counterparty. Under such an agreement, IMEA's primary responsibilities are to pay the price as agreed to in the contract and only handle the operational aspects of the BESS related to deciding when to charge or discharge the asset to maximize revenue. The obligation to build, maintain, and eventually decommission the BESS lies with the developer. All of the risks associated with thermal runaway, BESS availability, cost overruns, tariffs, and tax credit requirements stay with the developer as well.

BESS agreements can be structured in a multitude of ways. Most are priced in terms of $/kW-month of nameplate capacity. The primary driver of these prices is the size and duration of the BESS. The offtaker is paying the developer to have the BESS available at agreed upon levels of MWs and percentage of time available. Normally, the offtaker is considered the Market Participant (MP) – the entity responsible for deciding when to charge and discharge the battery. Considering the complexity needed to properly operate and manage a BESS, the offtaker would usually direct the developer as to when to perform these functions. The value of the BESS is so highly dependent upon the timing of its charge cycles that developers want the offtaker to decide when the BESS will operate or will charge a significant premium if the developer takes on that responsibility. Most contracts would allow the offtaker to "Toll" energy, paying a set amount for every MWH it wants to cycle.

One of the critical aspects of an ESSA for IMEA is to secure enough collateral that forces the vendor to perform both prior to construction as well as during and after construction. To make sure the vendor is obligated to perform his duties and enforce the contract as most counterparties are project only LLCs and do not have any assets to protect the offtaker from a loss.

4.4 Benefits

There are a variety of markets for which a battery project can be utilized to earn revenues or avoid costs. Those markets include ancillary services, energy arbitrage, load netting, and capacity payments. These markets can vary significantly by RTO and even by the respective Locational Marginal Pricing (LMP) node.

4.4.1 Ancillary Services

Batteries participating in ancillary services can provide regulation, reserves and voltage support. Regulation is the service of maintaining the grid's frequency near 60Hz and requires real power (or watts) in a matter of seconds. It is a critical function that has normally been performed by generation resources that are online and ready to mitigate supply and demand imbalances. Reserves are providing backup power during unexpected events. The required response times for reserves can range from instantaneous to just a few minutes. Voltage support helps to maintain stable voltage levels, requires fast response times, and uses reactive power.

The ability of lithium-ion batteries to respond extremely quickly makes them candidates to provide ancillary services for the grid. The majority of batteries utilizing ancillary services in PJM are 1-hour duration systems. The fast, short-duration responses needed for ancillary service make using a 1-hour system the most cost-effective design for ancillary services in PJM.

IMEA is considering a 4-hour duration battery. While it is technically possible to reserve 3 hours for energy arbitrage and load netting, and 1 hour for ancillary services. providing ancillary services causes the battery to degrade faster and precludes future utilization for energy arbitrage or load netting. Further, increased cycles of charging and discharging necessitated by ancillary services would raise expected ESSA costs because offtake agreements utilize total cycles as a key determinant in price.

Ancillary services have historically served as a reliable and stable cost recovery mechanism for batteries in PJM, but recent changes to that construct have put the future viability of ancillary services as a revenue stream at risk. Previous market designs led to disproportionately high payments, and improved system modeling is lowering the total market size for ancillary services. Because of PJM's ancillary services reforms and the limited market in MISO, staff will not model or plan to utilize a BESS for ancillary services.

4.4.2 Energy Arbitrage

Batteries can participate in energy arbitrage to seek revenue from the RTO's energy market. The concept is simple, energy prices in the respective RTO change every hour in the Day Ahead market and every five minutes in the Real Time market. Charging the battery when the energy price is low and discharging it when the energy price is high leads to an arbitrage opportunity to earn revenue. Deciding the optimal times to charge and discharge can be difficult to predict, especially as energy supply and demand dynamics shift due to increasing solar and wind energy production and the weather-driven intermittency of their output. The following are some of the important specifications that determine the overall effectiveness of using a battery to arbitrage energy.

- Round Trip Efficiency
    - The RTE of a battery is a key component in determining its overall efficiency of storing and releasing energy. For a lithium-ion battery this is around 85% except in winter, when, due to the impact of cold weather on a battery's ability to store energy, the efficiency is lower. Meaning, for every MW of energy that is used to store energy in a battery only 0.85 MW will be ultimately discharged.
- Duration of the Battery
    - Another critical component that determines a battery's overall efficiency and economics is the capacity of charging and discharging. A battery rated for 4-hour duration is, in theory, capable of charging and discharging to its rated amount for four hours.
- Cycle Life and Depth of Discharge
    - Cycle Life is the number of cycles a particular battery can be expected to perform during its lifetime. Depth of discharge refers to the level to which a battery has had its energy discharged. A battery charged to 100% or discharged to 0% leads to quicker degradation of the battery over its lifetime. Batteries are typically asked to charge only up to 90% of their rating and discharged down to 20% of their rating. Developers often account for this by oversizing the battery.

4.4.3 Load Netting Opportunities

Load netting refers to discharging BESS during the periods of highest overall system demand in an effort to reduce transmission and capacity charges. Load netting is subjected to each RTO's respective Tariffs, Transmission Owner rules and regulations, and Federal Energy Regulatory Commission (FERC) compliance. Both PJM and MISO calculate IMEA's load charges related to capacity and transmission obligations based on usage during certain times of peak demand. Said differently, these charges are calculated based off IMEA's "contribution" to energy demand at the times when energy demand is at its highest. Behind-the-meter BESS can effectively lower contribution to peak demand by discharging reserves and lowering the total amount of energy demanded by IMEA.

In MISO, these charges are calculated based on each month's peak demand for network transmission obligations and seasonally for capacity planning requirements. In PJM, these charges are calculated based on the peak demand for the entire year. By discharging stored energy during these peak intervals, a BESS may reduce IMEA's measured load at the systemwide peak. This lowers the demand-related charges assessed by the RTOs and helps minimize costs tied to capacity and transmission obligations.

Peak demand periods have historically been when reliability risk is at its highest, and fairly predictable – concentrated in late summer afternoons at times of maximum air conditioning usage. However, as intermittent resources continue to make up a greater share of generation, RTOs have begun to witness reliability risk shift away from the peak to the periods during which the difference between what intermittent resources are able to generate and the amount of energy demanded, is at its highest – warm, windless, summer and cold, windless, winter nights.

Modeling peak demand under these new conditions presents challenges. Traditional load forecasting relied on long-term weather patterns, historical consumption data, and predictable load patterns. Today, however, there is significant uncertainty. A hot, windless summer evening or an overcast winter morning can cause unexpected, unmodeled system peaks. This variability makes it challenging for RTOs and LSEs to pinpoint when exactly peaks will occur. Furthermore, industrial consumers of electricity have modified behavior in recent years to avoid the costly charges incurred by contributing to energy demand peaks. It is now common practice to use less energy over a longer period of time. This has multiple impacts on BESS. First, peaks are longer – sometimes too long to be covered by a standard duration of a 4-hour BESS alone. Second, peaks are increasingly more difficult to predict. BESS serves a role in contributing to reliability during shoulder hours, but industrywide trends complicate the practice of load netting, irrespective of the resource.

4.4.3.1 In PJM

In PJM, there are two types of Behind-The-Meter-Generation (BTMG. A behind-the-meter, peak-shaving resource operated by a municipal utility is categorized as Non-Retail BTMG (NRBTMG)[47]. When IMEA's NRBTMG operates during the system's highest demand periods, the output can be netted from IMEA's total contribution to peak load. Failure to perform can result in the elimination of 10% of NRBTMG capacity from netting calculations. This forces the unit to participate directly in the PJM market similar to a grid-connected storage asset. PJM places an RTO-wide limit of 3,000 MW on the total amount of non-retail BTMG that can qualify for netting. Once that cap is reached, additional projects can still operate and participate in energy or capacity markets, but they will no longer be able to offset transmission costs through reduced load measurements. The most recent data available shows that PJM is not near this cap, but that could change quickly.

The second type of BTMG is Retail BTMG, known in PJM simply as BTMG. In a recent ruling on Co-located load within PJM, FERC declared PJM's existing tariff, as it pertains to retail BTMG, to be unjust and unreasonable, and has directed PJM to revise its retail BTMG rules. Under such revisions, PJM is to establish a threshold of load which is eligible to be netted from total load, as well as other rules surrounding the eligibility of BTMG load netting. FERC has affirmed PJM's NRBTMG rules to be just and reasonable due to the aforementioned 3,000 MW system cap. Nonetheless, the elimination of load netting is a risk present in the lifecycle of BESS.

4.4.3.2 In MISO

MISO defines network load as all load interconnected to its system. As a general rule, netting is not allowed in MISO. However, during discussions surrounding Wholesale Connection Agreements (WCA) with Ameren, IMEA staff were able to create a general rule of implementation that for each member delivery point up to 5 Mega Volt-Amperes (MVAs) of resource netting is allowed -- subject to future MISO rules and requirements. 1 MVA is equal to roughly 1 MW. MISO's general rule requires all resources greater than 10 MVA to be reported for planning and modeling. However, this threshold is currently planned to be lowered to 1 MVA. The rules in both MISO and PJM show that transmission savings as a source of revenue is associated with its own risk and is subject to RTO rules. While available today, load netting revenue is not guaranteed in the future.

4.4.4 Capacity Accreditation and Resource Adequacy Pricing

One of the most consequential changes made by both PJM and MISO in recent years has been the transition from accrediting resources according to their general peak performance to accrediting resources using marginal reliability-based methodologies. Under the old

[47] https://www.pjm.com/-/media/DotCom/documents/manuals/m14d.ashx

method of Peak Coincident Load (PCL), a resource's capacity value was measured by its contribution at the time of the system's peak demand. This approach aligned well with a generation fleet composed primarily of dispatchable thermal resources which could generally be relied upon to respond to operator instructions during peak times of energy usage, with the exception of unplanned outages.

As the resource mix has shifted toward a greater reliance on intermittent resources, however, the limitations of accrediting resources for their performance during peak periods have become more apparent. Intermittent resources do not generate on-demand, and their contributions during the times of the greatest reliability risk can vary significantly based on weather conditions. Moreover, the timing of system peaks has itself begun to change, with growing evidence of risk during winter periods in particular.

In response, RTOs have begun adopting marginal reliability-based accreditation. PJM implemented its Effective Load Carrying Capability (ELCC) framework in 2024[48], and MISO has introduced its own version, the Direct Loss of Load (DLOL) methodology, which will take effect in 2028[49]. These approaches aim to measure each resource's contribution to reducing the probability of system shortfalls, thereby aligning accredited capacity with actual reliability value. Put differently, accreditation is shifting from a focus on performance during periods of peak demand to performance during periods of peak system risk.

The full impacts of this change are still unfolding, but several implications are already evident. For intermittent resources, the RTO determined capacity values decline as more of the same type of resource is added to the system, reflecting the RTO's determination of diminishing reliability benefit of additional units.

4.4.4.1 In PJM

The following table is PJM's Preliminary ELCC Class Ratings for Delivery Year (DY) 2027/2028 - Delivery Year 2035/2036[50]

[48] https://www.pjm.com/-/media/DotCom/committees-groups/task-forces/elccstf/postings/elcc-capacity-accreditation-methodology-problem-statement.pdf
[49] https://www.rtoinsider.com/90464-ferc-approves-miso-probabilistic-capacity-accreditation/
[50] https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings.pdf

ELCC Class	2027/ 28	2028/ 29	2029/ 30	2030/ 31	2031/ 32	2032/ 33	2033/ 34	2034/ 35	2035/ 36
Onshore Wind	41%	37%	35%	34%	31%	26%	22%	20%	19%
Offshore Wind	68%	61%	57%	53%	47%	38%	32%	28%	26%
Fixed-Tilt Solar	7%	6%	6%	6%	6%	6%	6%	6%	6%
Tracking Solar	9%	7%	7%	7%	7%	7%	7%	7%	7%
Landfill Intermittent	50%	51%	51%	50%	50%	50%	50%	51%	51%
Hydro Intermittent	40%	37%	37%	38%	39%	39%	38%	38%	38%
4-hr Storage	52%	50%	42%	37%	30%	25%	25%	24%	23%
6-hr Storage	61%	60%	52%	48%	41%	36%	36%	35%	33%
8-hr Storage	65%	64%	58%	54%	49%	44%	45%	43%	42%
10-hr Storage	74%	73%	68%	64%	59%	55%	56%	54%	53%
Demand Resource	85%	82%	77%	74%	70%	68%	68%	67%	66%
Nuclear	95%	95%	95%	95%	95%	95%	96%	95%	95%
Coal	83%	83%	83%	83%	82%	81%	81%	80%	80%
Gas Combined Cycle	74%	75%	75%	75%	76%	77%	78%	78%	78%
Gas CT	61%	61%	62%	63%	64%	66%	68%	69%	70%
Gas CT Dual Fuel	78%	77%	77%	77%	78%	80%	80%	80%	80%
Diesel Utility	91%	91%	91%	91%	91%	91%	91%	91%	91%
Steam	73%	72%	71%	71%	72%	72%	72%	72%	72%

Image source: https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings.pdf

PJM's indicative ELCC Class Ratings demonstrate the expected decreases in accreditation levels for storage. A 4-hour storage resource starts at 52% and drops down to 23% in the final year of PJM's projections. This forward look at capacity values raises doubts about the viability of not only storage projects, but also wind and solar resources to earn sufficient revenues in the PJM's capacity market. Despite recent record high capacity prices that are expected to remain elevated for the foreseeable future, decreasing accreditation levels could diminish the economics of storage.

A standard 20-year offtake agreement would extend IMEA's capacity exposure for a BESS at least 10 years beyond the above projections. The average annual accreditation change for these projections is -4% with the majority of the decrease occurring in earlier years. It has been assumed that the annual accreditation change beyond 2035/36 will be -1% annually to round out a hypothetical 20-year ESSA.

4.4.4.2 In MISO

MISO will transition to their new Direct Loss of Load (DLOL) methodology for PY2028/29, but they have put out indicative class-level accreditation percentages by season had the methodology been used in the PY2026-27 auction.

Indicative Resource Class-level UCAP (DLOL) Results

Indicative Resource Class-level UCAP based upon the DLOL methodology and expressed as a percentage of installed capacity (ICAP) are presented in the table below.[1]

PY 2026-2027	DLOL-Based UCAP %				ICAP				Count of Units
	Summer	Fall	Winter	Spring	Summer	Fall	Winter	Spring	End of PY
Biomass	90%	82%	84%	82%	452	462	459	437	33
Coal	88%	72%	69%	63%	35,952	35,714	36,170	32,758	145
Combined Cycle	95%	77%	74%	71%	27,686	28,608	30,987	30,022	142
Dual Fuel Oil/Gas	89%	73%	67%	71%	7,335	7,686	7,928	7,546	72
Gas	91%	73%	63%	64%	28,195	29,381	31,924	29,674	415
Nuclear	95%	85%	85%	78%	11,375	11,479	11,719	12,366	17
Oil	84%	77%	52%	56%	1,206	1,207	1,189	1,192	133
Pumped Storage	96%	74%	85%	68%	2,628	2,671	2,594	2,632	14
Reservoir Hydro	97%	87%	94%	87%	476	448	459	473	29
Run-of-River Hydro	93%	83%	86%	78%	768	604	701	798	66
Solar	40%	4%	2%	7%	18,772	19,782	24,162	25,141	347
Storage	55%	70%	74%	99%	1,114	1,134	1,475	1,733	67
Wind	7%	12%	24%	15%	29,338	29,358	30,111	30,111	312

The storage accreditation is based upon the Even Loss methodology as presented in the April 2025 Resource Adequacy Subcommittee.

Image source: https://cdn.misoenergy.org/PY26-27%20Indicative%20DLOL-based%20UCAP%20%20PRMR%20Results738545.pdf

MISO's analysis projects higher capacity accreditation values than PJM for equivalent resources. This is in part due to MISO's seasonal construct, as well as key differences in capacity accreditation modeling between the two RTOs. In addition, MISO is largely constituted by vertically integrated utilities whose resources are largely hedged against short-term fluctuations in capacity markets. MISO's values are significantly higher than those of PJM for storage. Future indicative numbers published by MISO show BESS retaining high accreditation values until at least 2031[51]. MISO's indicative accreditation levels for storage are lower for the summer partly because batteries are less efficient during extreme temperatures. The summer is also the season most likely to see the highest capacity clearing prices due to increased electrical demand. This adds significant risk to the expected capacity revenue of a BESS in the MISO market.

4.4.4.3 Resource Adequacy Pricing

PJM's primary capacity auction is called the Base Residual Auction; the following chart shows results of those auctions in the column labeled "Resource Clearing Price" (shown in Dollars per MW-Day) from Delivery Year 2016/17 to Delivery Year 2026/2027. For context, $30/MW-Day is roughly equivalent to $1.00 per kW-Month. PJM's max price shown of $329.17/MW-Day is roughly equivalent to $10/kW-Month. Most BESS which IMEA has been quoted cost between $15-$17/kW-Month.

2026/2027 Base Residual Auction Report

Table 2. RPM Base Residual Auction Resource Clearing Price Results in the RTO

	Auction Results				
Delivery Year	Resource Clearing Price	Cleared UCAP (MW)	RPM Reserve Margin[1]	Total Reserve Margin[1,2,7]	Cleared MW Times Clearing Price ($ billion)
2016/17[3]	$59.37	169,159.7	20.7%	20.3%	$5.5
2017/18	$120.00	167,003.7	20.1%	19.7%	$7.5
2018/19	$164.77	166,836.9	20.2%	19.8%	$10.9
2019/20	$100.00	167,305.9	22.9%	22.4%	$7.0
2020/21[4]	$76.53	165,109.2	23.9%	23.3%	$7.0
2021/22	$140.00	163,627.3	22.0%	21.5%	$9.3
2022/23	$50.00	144,477.3	21.1%	19.9%	$3.9
2023/24	$34.13	144,870.6	21.6%	20.3%	$2.2
2024/25	$28.92	147,478.9	21.7%	20.4%	$2.2
2025/26[5]	$269.92	135,684.0	18.6%	18.5%	$14.7
2026/27[6]	$329.17	134,205.3	18.9%	18.9%	$16.1

[1] Reserve Margins converted to ICAP using Pool-Wide AUCAP Factor; [2] Total Reserve Margin includes FRR+RPM (Total ICAP/Total Peak-1); [3] 2016/2017 BRA includes EKPC zone; [4] Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers; [5] DOM zone included in RPM; [6] EE removed from Market; [7] Total Reserve margin does not include FRR commitments to meet the threshold to allow sales into RPM.

Image source: https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-bra-report.pdf

[51]https://cdn.misoenergy.org/20250409%20RASC%20Item%2008%20LOLE%20Modeling%20Enhancements%20Storage%20Modeling689245.pdf

This table shows the historical Summer Auction Clearing Prices for MISO[52] (Illinois is in Zone 4). It should be noted that an error was discovered after the 2025/2026 auction which effectively revised the summer clearing price down to $459.10 per MW-Day, however MISO has been approved to adjust their methodology going forward which would have made the original $666.50 the actual auction result for the Summer of 2025. With many years clearing under even $30/MW-Day ($1.00/kW-Month), paying $12-$15/kW-Month for a BESS would have been uneconomic.

Historical Summer Auction Clearing Price Comparison

<table>
<tr><th>PY</th><th>Zone 1</th><th>Zone 2</th><th>Zone 3</th><th>Zone 4</th><th>Zone 5</th><th>Zone 6</th><th>Zone 7</th><th>Zone 8</th><th>Zone 9</th><th>Zone 10</th><th>ERZs</th></tr>
<tr><td>2015-2016</td><td colspan="3">$3.48</td><td>$150.00</td><td colspan="3">$3.48</td><td colspan="2">$3.29</td><td>N/A</td><td>N/A</td></tr>
<tr><td>2016-2017</td><td>$19.72</td><td colspan="6">$72.00</td><td colspan="3">$2.99</td><td>N/A</td></tr>
<tr><td>2017-2018</td><td colspan="10">$1.50</td><td>N/A</td></tr>
<tr><td>2018-2019</td><td>$1.00</td><td colspan="9">$10.00</td><td>N/A</td></tr>
<tr><td>2019-2020</td><td colspan="6">$2.99</td><td>$24.30</td><td colspan="4">$2.99</td></tr>
<tr><td>2020-2021</td><td colspan="6">$5.00</td><td>$257.53</td><td>$4.75</td><td>$6.88</td><td>$4.75</td><td>$4.89-$5.00</td></tr>
<tr><td>2021-2022</td><td colspan="7">$5.00</td><td colspan="3">$0.01</td><td>$2.78-$5.00</td></tr>
<tr><td>2022-2023</td><td colspan="7">$236.66</td><td colspan="3">$2.88</td><td>$2.88-236.66</td></tr>
<tr><td>Summer 2023</td><td colspan="11">$10.00</td></tr>
<tr><td>Summer 2024</td><td colspan="11">$30.00</td></tr>
<tr><td>Summer 2025</td><td colspan="11">$666.50</td></tr>
</table>

- Auction Clearing Prices shown in $/MW-Day

Image source: https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

4.5 Financial Analysis-IMEA Staff

While costs of lithium-ion batteries have declined significantly in recent years, ESSA rates have not yet come down by a similar magnitude. Renewable portfolio standards and carbon reduction goals or requirements are promoting demand. When the tax credits for wind and solar expire at the end of 2027, much of the industry's focus is expected to turn to BESS. Tariffs and FEOC requirements, however, are expected to increase costs or incentivize the development of alternatives to lithium-ion batteries. The need for longer storage duration and reduced safety hazards may also take away market share from lithium-ion in the future. For now, this study will utilize a standard 4-hour lithium-ion battery storage unit which is the predominant technology for BESS. Entering into an offtake agreement can stabilize expenses by paying a set price for the term.

[52] https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

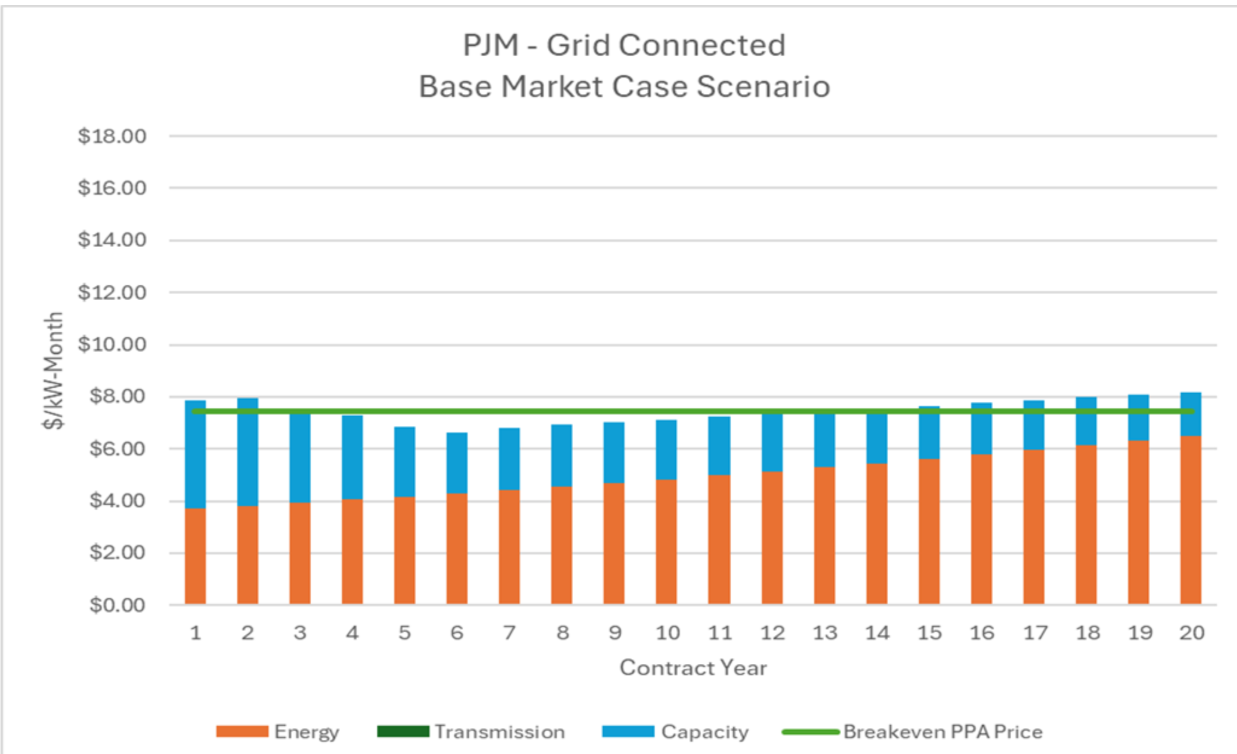
The certainty of revenue sources for batteries is just as unclear as the future cost of batteries. The future of ancillary services revenues in PJM appears to be diminishing. Energy arbitrage is highly dependent upon having times of energy excess and scarcity and knowing when those times are at their peak. Load netting opportunities are also being further reduced by the RTOs as the shift in generation resources increases the reliability risks. The future capacity values of BESS also appear uncertain as their projected accreditation levels seem to be decreasing in the future. The analysis performed by staff includes projected revenues as well as a forecasted break-even ESSA price.

IMEA has taken the approach of only estimating projected revenues during the life of a 20-year offtake agreement to then arrive at the economic breakeven price for an ESSA. IMEA has not undertaken an estimate of the cost of the BESS as the size and location can dramatically affect the pricing. If IMEA proceeds with a BESS pilot, it will perform an RFP to obtain current market pricing.

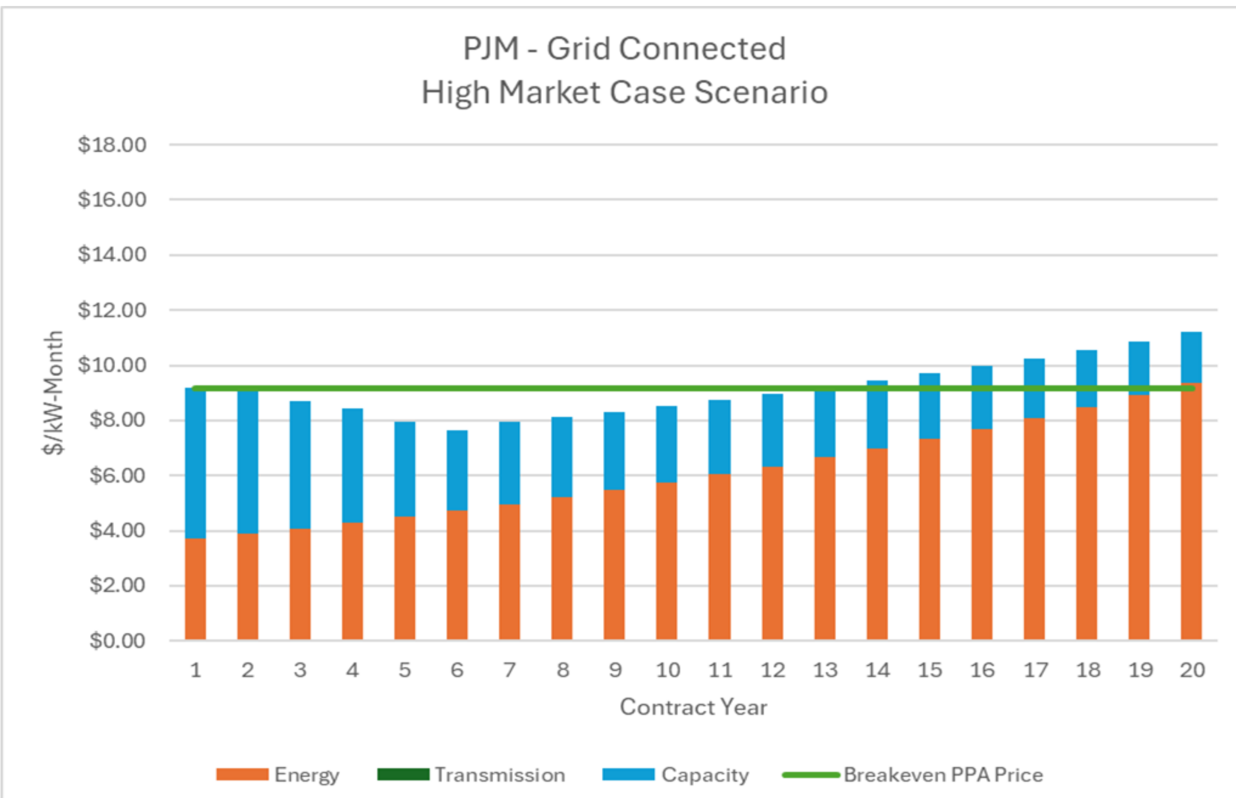
4.5.1 PJM Cost Benefit Analysis-Grid-Connected

Grid-Connected batteries are connected directly to PJM operated facilities and/or registered to directly participate in PJM markets. A grid-connected BESS would be charged and discharged directly by PJM. There are no transmission network cost savings as these resources are either connected to PJM through an interconnection queue or as a unit on a member distribution system that reported as a PJM resource.

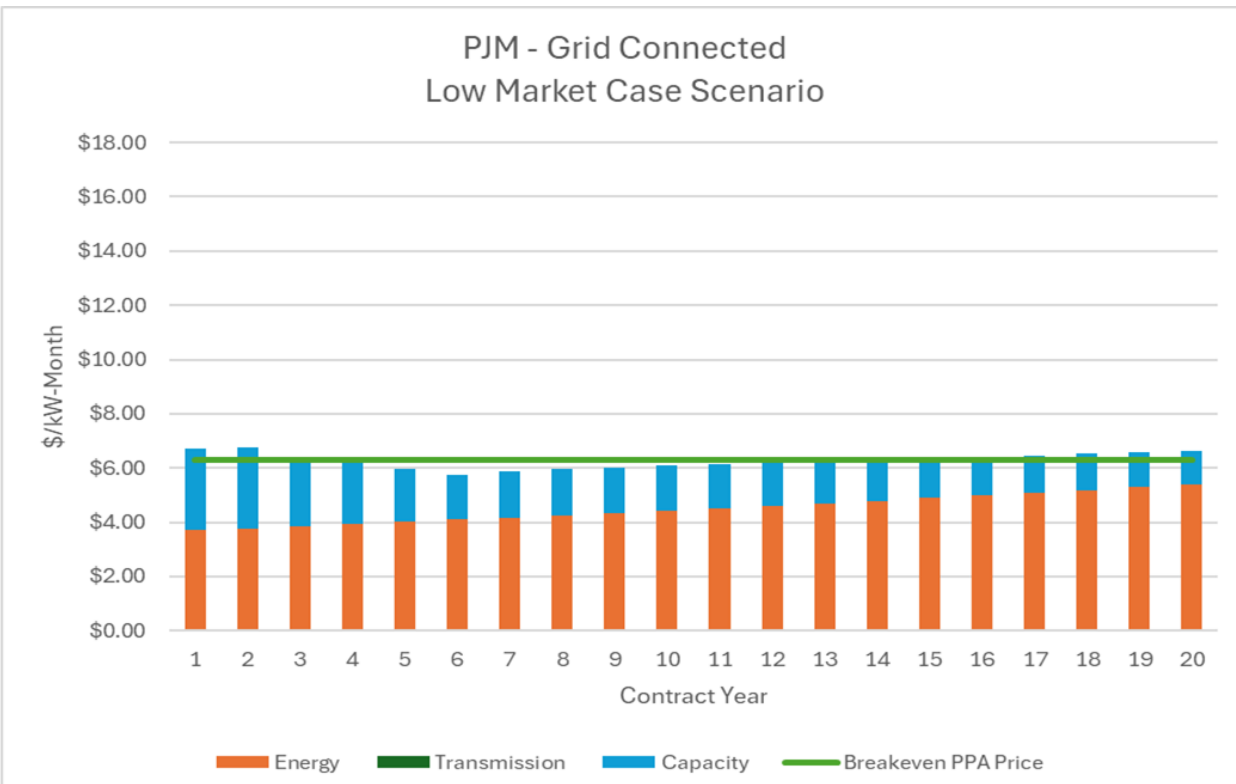
Key Assumptions: Base Case scenario: Grid-Connected, PJM's Capacity Accreditation estimates through 2035 with similar levels for the remaining life of the asset. Capacity pricing starting at $250 per MW-Day (or $7.60 per kW-Month) and accelerating at 3% percent year over year. Energy arbitrage opportunities are projected to increase year over year by 3% to account for volatility in the energy market.



Key Assumptions: High Market Case scenario: Grid-Connected, PJM's Capacity Accreditation estimates through 2035 with similar levels for the remaining life of the asset. Capacity pricing starting at the PY2026-27 BRA results of $329.17 $/MW-day (or approximately $10 per kW-Month) and accelerating at 2% percent year over year. Energy arbitrage opportunities are projected to increase year over year by 5% to account for volatility in the energy market.



Key Assumptions: Low Market Case scenario: Grid-Connected, PJM's Capacity Accreditation estimates through 2035 with similar levels for the remaining life of the asset. Capacity pricing starting at $180 per MW-Day (or approximately $5.50 per kW-Month) and accelerating at 3% percent year over year. Energy arbitrage opportunities are projected to increase year over year by 2% to account for volatility in the energy market.

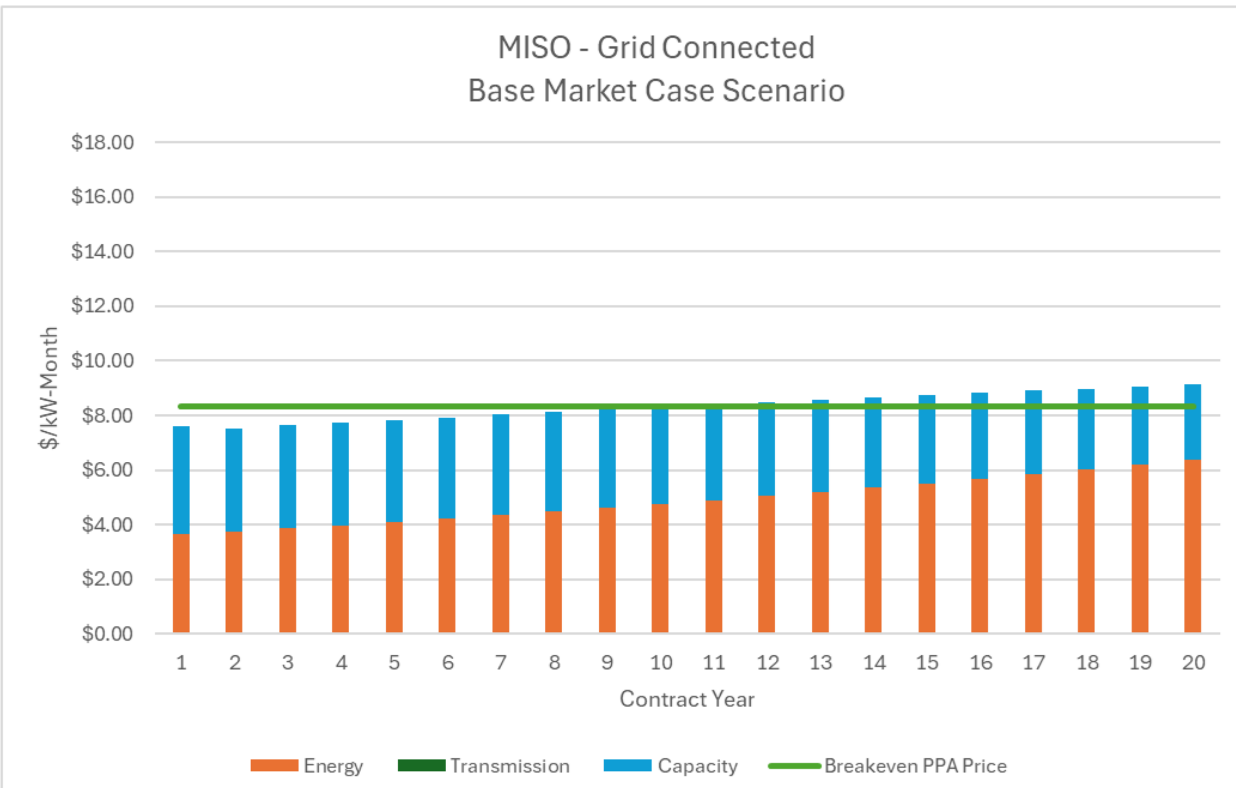


Conclusion: For a PJM Grid-Connected 4-hour BESS, the projected revenue from the RTO is between $6.00/KW-Month and $9.00/KW-Month. For a beneficial addition to IMEA portfolio, an Energy Storage Service Agreement should be as close to $8.00/KW-Month as possible.

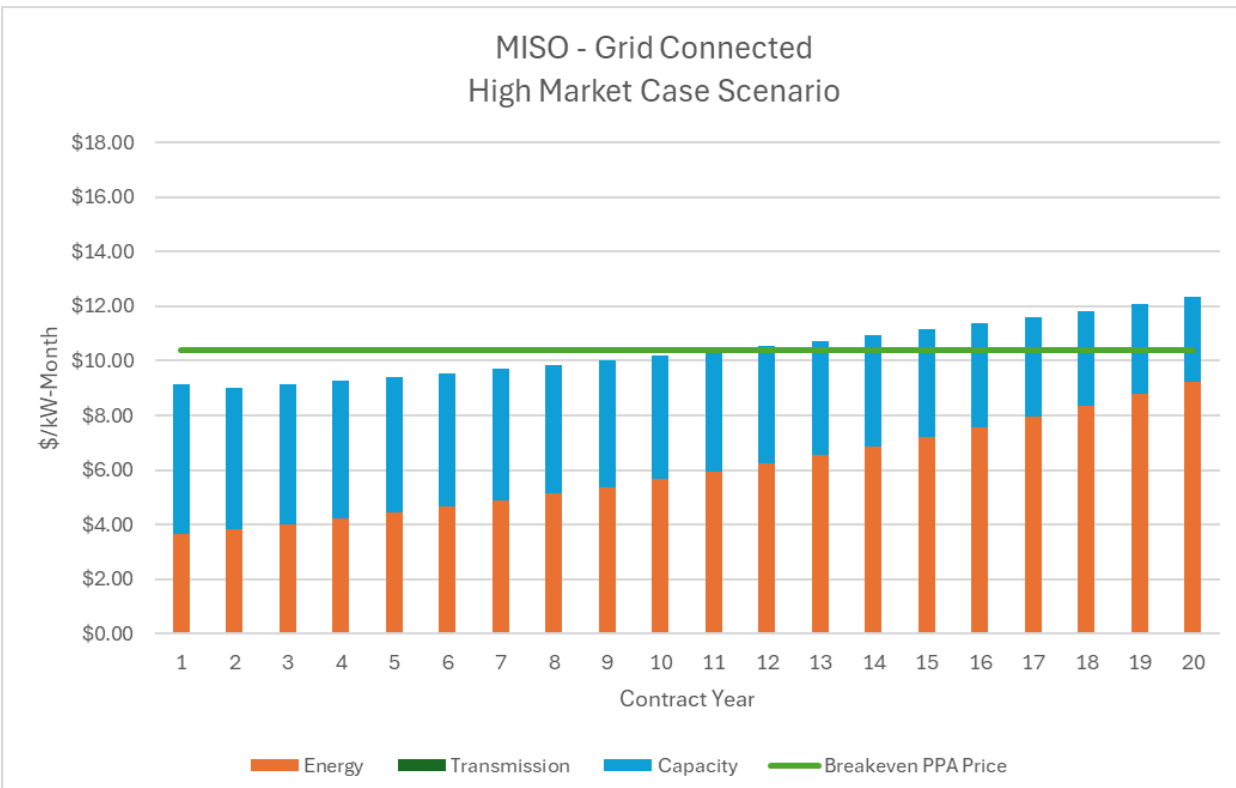
4.5.2 MISO Cost Benefit Analysis – Grid-Connected

MISO connected batteries are connected directly to MISO operated facilities and/or registered to directly participate in MISO markets. The BESS is charged and discharged directly by MISO. There are no Transmission network cost savings as these resources are either connected to MISO through an interconnection queue or a unit on member distribution system reported as a MISO resource.

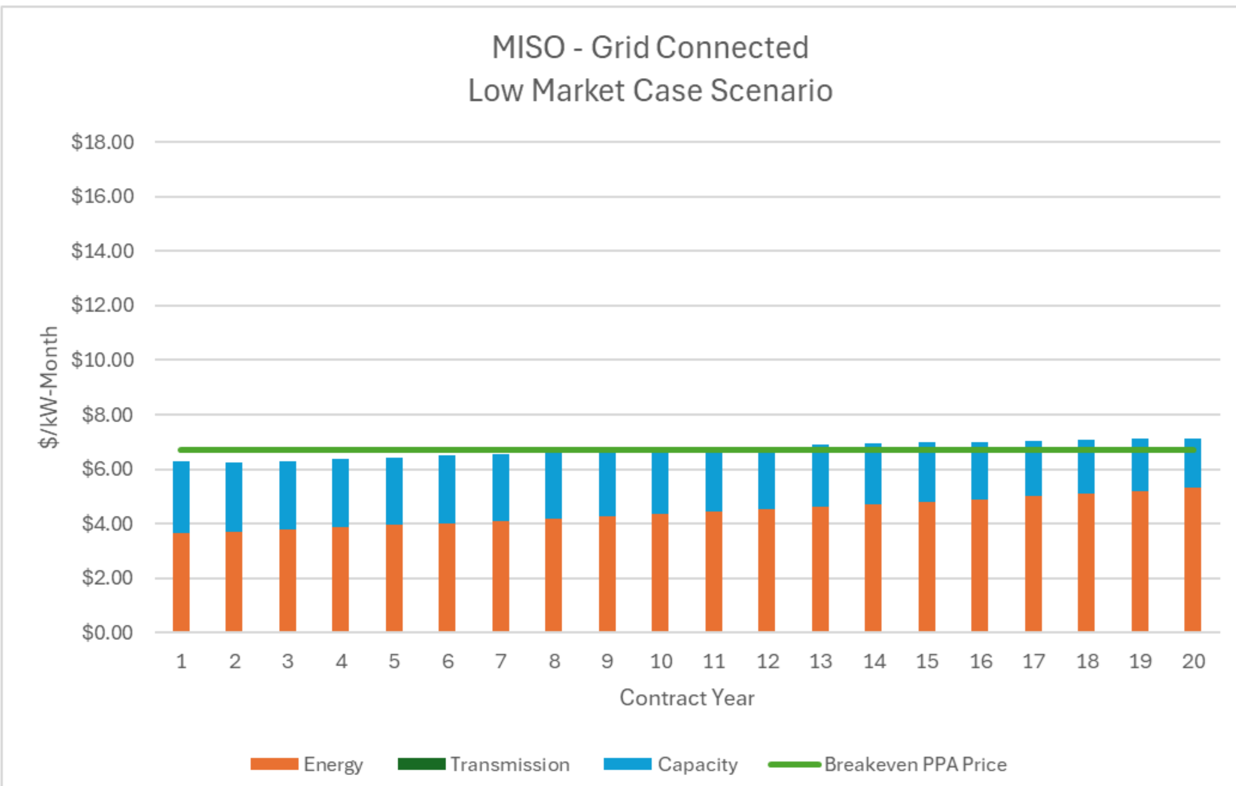
Key Assumptions: Base Case scenario: Grid-Connected, MISO's PY25/26 DLOL Capacity Accreditation estimates applied to the first year with decreasing accreditation each year thereafter. Capacity pricing starting for PY2027-28 assumed at an annualized $180/MW-Day (approximately $5.50/kW-Month) and accelerating at 3% percent year over year. Energy arbitrage opportunities increase year over year by 3% to account for volatility in energy market.



Key Assumptions: High Case scenario: Grid-Connected, MISO's PY25/26 DLOL Capacity Accreditation estimates applied to the first year with decreasing accreditation each year thereafter. Capacity pricing starts for PY2027-28 at annualized $250/MW-Day (approximately $7.60/kW-Month) and accelerates at 2% percent year over year. Expected energy arbitrage opportunities increase year over year by 5% to account for volatility in energy market.



Key Assumptions: Low Case scenario: Grid-Connected, MISO's PY25/26 DLOL Capacity Accreditation estimates applied to the first year with decreasing accreditation each year thereafter. Capacity pricing starts for PY2027-28 at $120/MW-Day ($3.65/kW-Month) and accelerates at 3% percent year over year. Energy arbitrage opportunities increase year over year by 2% to account for volatility in energy market.

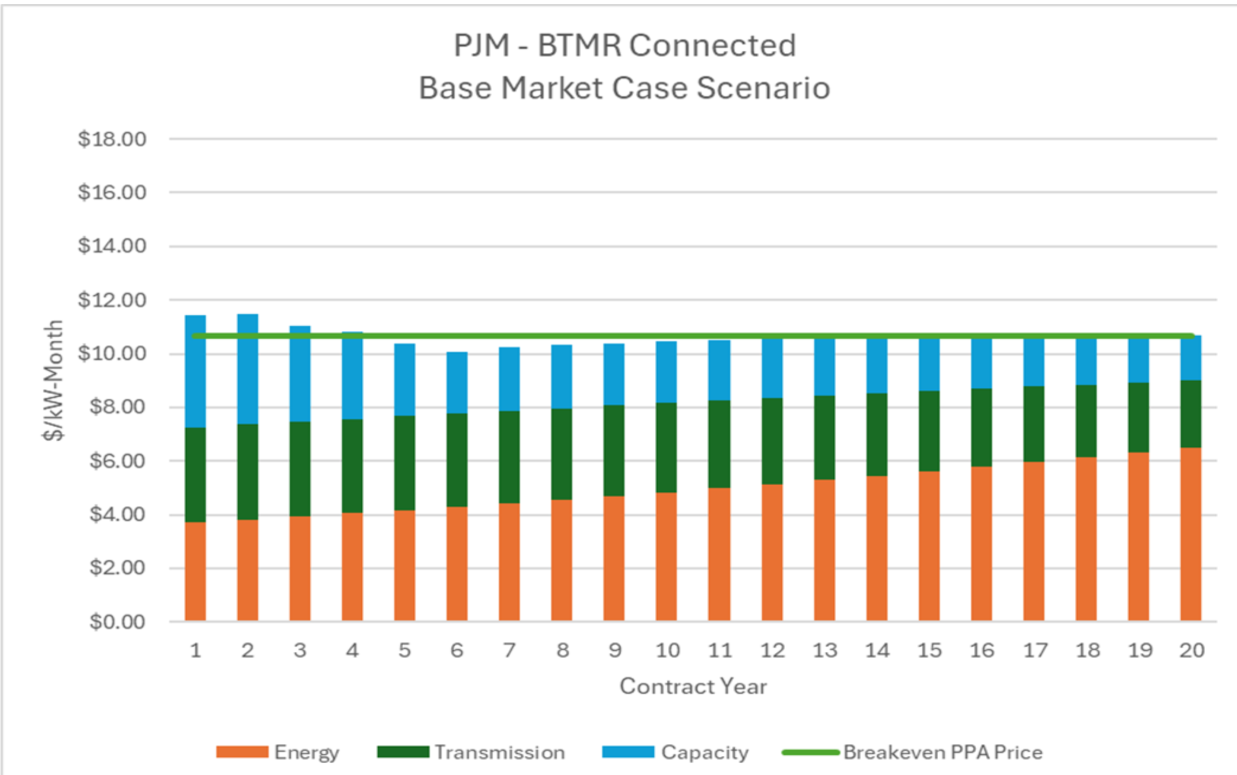


Conclusion: For MISO Grid-Connected 4-hour BESS, the projected revenue from the RTO is between \$7.00/KW-Month and \$10.50/KW-Month. For a beneficial addition to IMEA portfolio, an Energy Storage Service Agreement should be as close to \$8.00/KW-Month as possible.

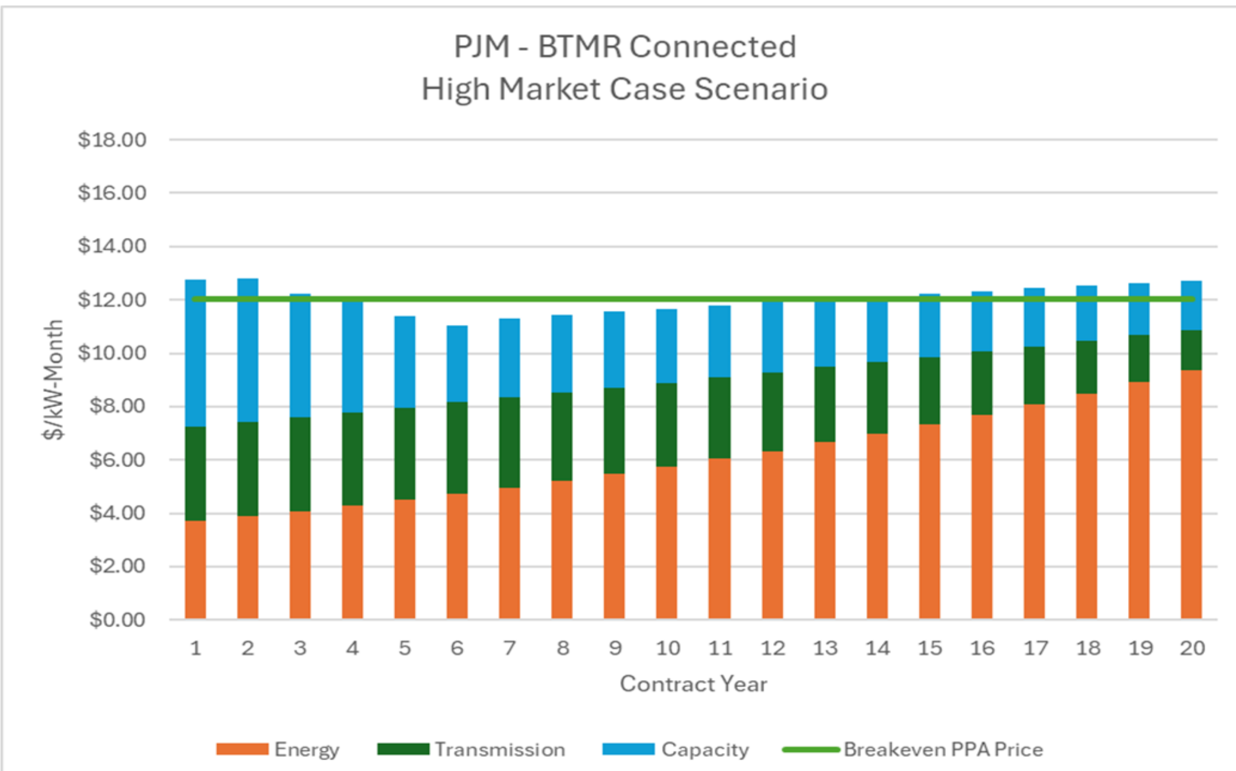
4.5.3 PJM Cost Benefit Analysis - *Behind the-Meter-Resource (BTMR)*

Behind-the-meter BESS is connected to a member distribution system and is not directly registered and/or dispatched by PJM. The BESS is charged and discharged directly by IMEA, and the savings would come from avoided costs. The charging cycle is subject to all costs of load including PJM transmission, ancillary, and administrative charges. Netting of the load could yield transmission cost avoidance subjected to BTMG rules and performance requirements in PJM (network portion only).

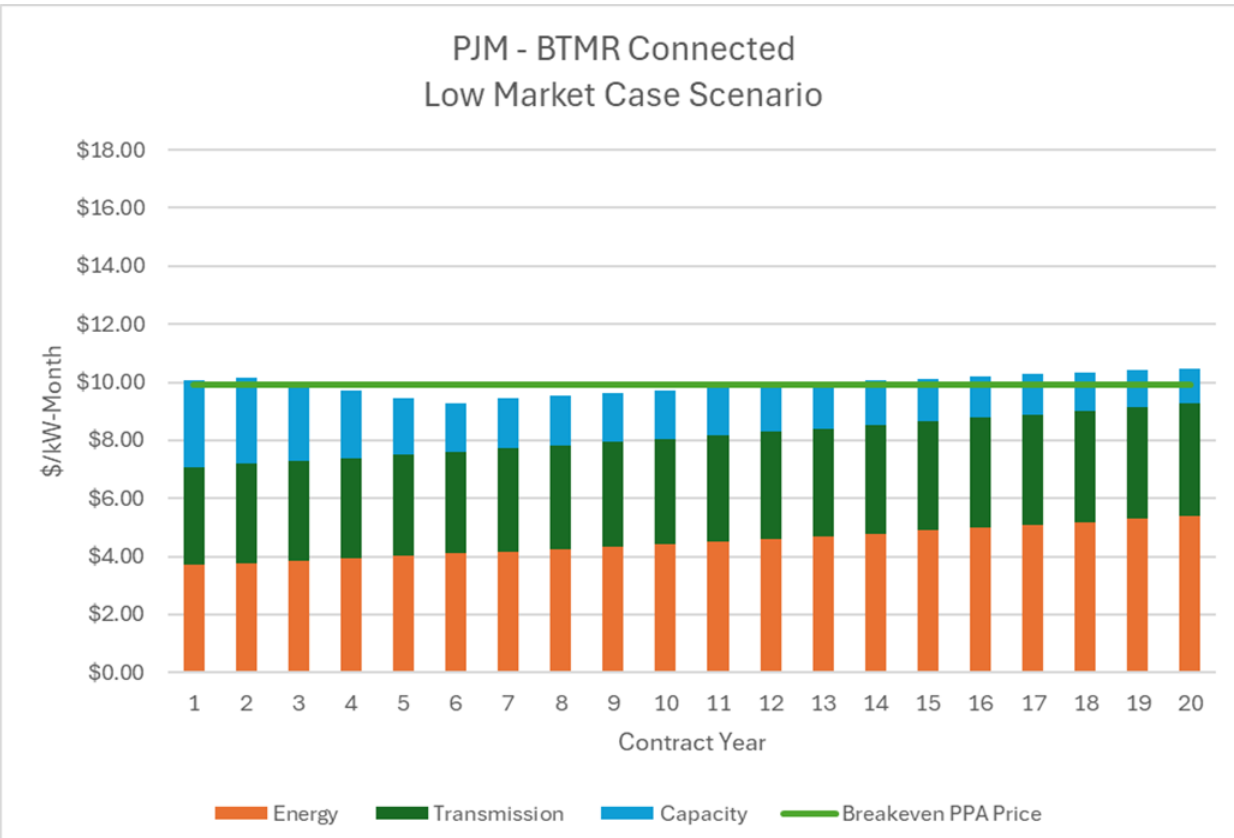
Key Assumptions: Base Case scenario: member-connected BTMR, PJM's Capacity Accreditation estimates through 2035 with similar levels for the remaining life of the asset. Capacity pricing starts at $250 per MW-Day ($7.60/kW-Month) and accelerates at 3% percent year over year. Energy arbitrage opportunities are projected to increase year over year by 3% to account for volatility in the energy market. Transmission costs increase 3% year over year with an initial transmission peak load reduction of 95% of the BESS nameplate capacity (with a 3% loss in Year over Year ability to reduce peak).



Key Assumptions: High Market Case scenario: member-connected BTMR, PJM's Capacity Accreditation estimates through 2035 with similar levels for the remaining life of the asset. Capacity pricing starts at the PY2026-27 BRA results of $329.17 $/MW-day (approximately $10/kW-Month) and accelerates at 2% percent year over year. Energy arbitrage opportunities are projected to increase year over year by 5% to account for volatility in the energy market. Transmission costs increase by 4% year over year with an initial transmission peak load reduction of 95% of the BESS nameplate capacity (with a 4% loss in year over year ability to reduce peak).



Key Assumptions: Low Market Case scenario: member BTMR, PJM's Capacity Accreditation estimates through 2035 with similar levels for the remaining life of the asset. Capacity pricing starts at $180 per MW-Day (approximately $5.50/kW-Month) and accelerates at 3% percent year over year. Energy arbitrage opportunities are projected to increase year over year by 2% to account for volatility in the energy market. Transmission costs increase by 2% year over year with an initial transmission peak load reduction of 90% of the BESS nameplate capacity (with a 1% loss in year over year ability to reduce peak).

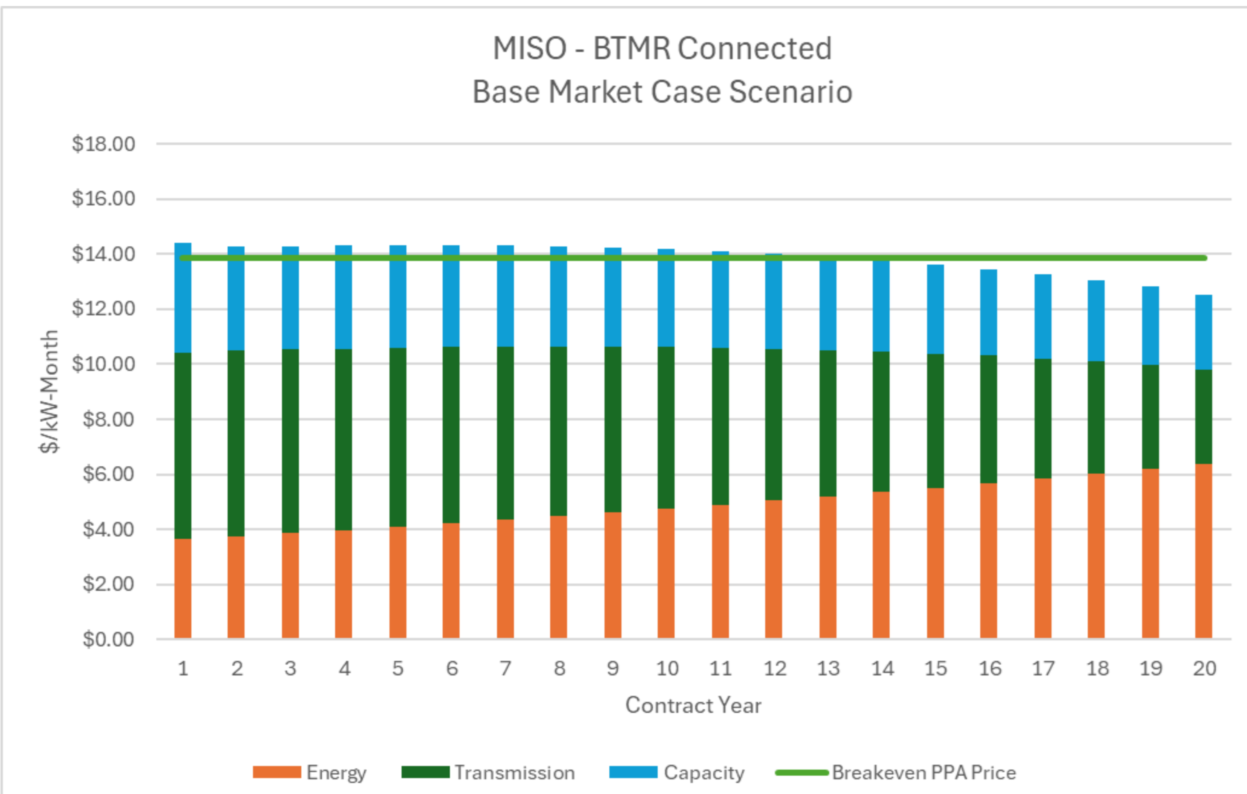


Conclusion: For PJM member-connected 4-hour BESS, the projected revenue/savings from the RTO is between $10/KW-Month and $12/KW-Month. For a beneficial addition to IMEA portfolio, an Energy Storage Service Agreement should be as close to $11.00/KW-Month as possible.

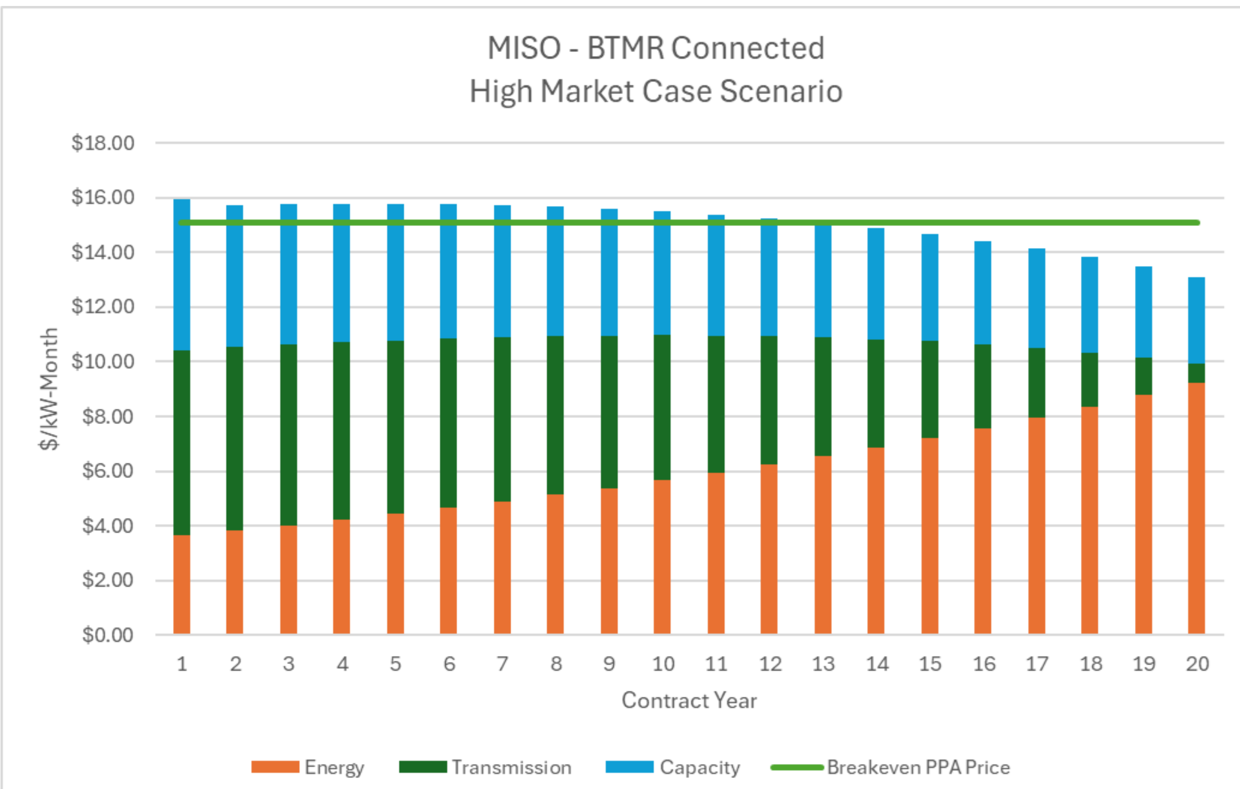
4.5.4 MISO Cost Benefit Analysis- Behind-the-Meter Resource

Behind-the-meter BESS is connected to a member distribution system and is not directly registered and/or dispatched by MISO. The BESS is charged and discharged directly by IMEA, and the savings would come from avoided cost. The charging cycle is subject to all the costs of the load including MISO transmission, ancillary, and administrative charges. Netting of the load could yield transmission cost avoidance subjected to the WCA 5 MVA limit and MISO tariff rules and performance requirements in MISO.

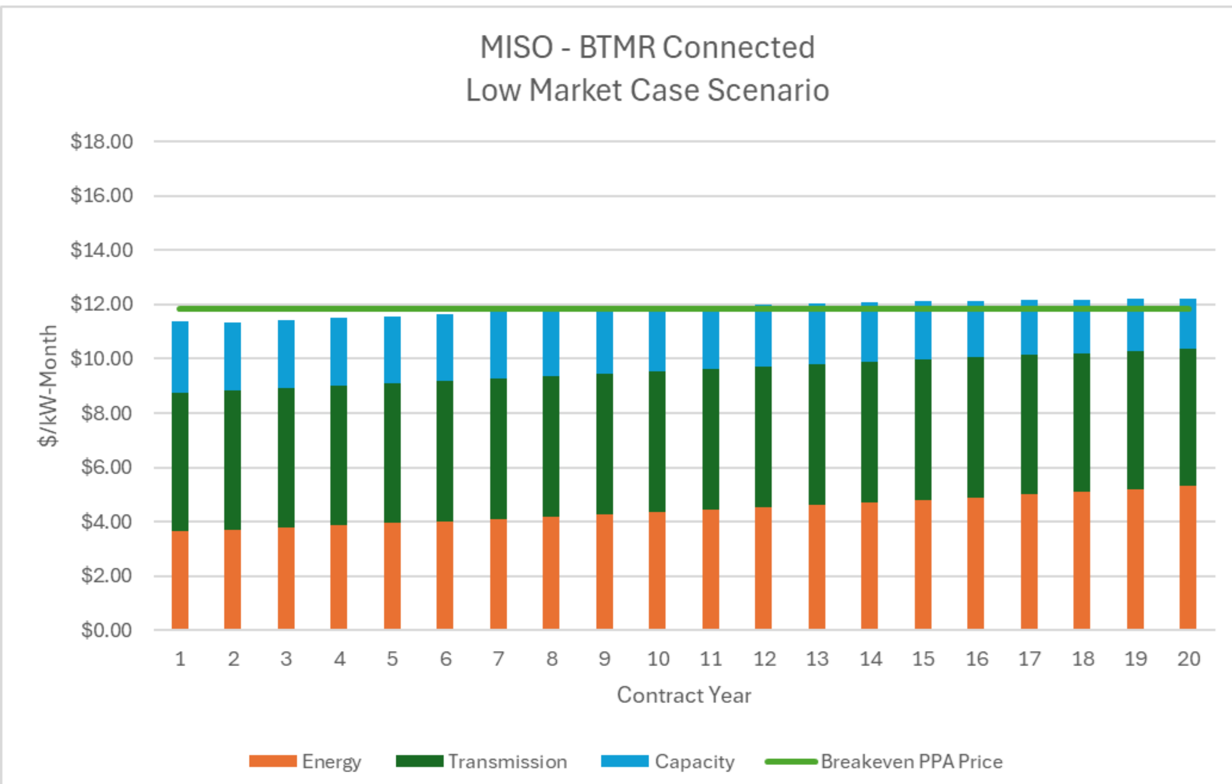
Key Assumptions: Base Case scenario: Member-connected behind-the-meter BESS, MISO's PY25/26 DLOL Capacity Accreditation estimates applied to the first year with decreasing accreditation each year thereafter. Capacity pricing for PY2027-28 starts at $180/MW-Day annualized (approximately $5.50 per kW-Month) and accelerates at 3% percent year over year. Energy arbitrage opportunities increase year over year by 3% to account for volatility in energy market. Transmission costs increase 3% each year and with initial transmission peak load reduction of 80% of the BESS nameplate capacity (with a 3% loss in year over year ability to reduce peak).



Key Assumptions: High Case scenario: Member-connected behind-the-meter BESS, MISO's PY25/26 DLOL Capacity Accreditation estimates applied to the first year with decreasing accreditation each year thereafter. Capacity PY2027-28 starts at an annualized $250/MW-Day ($7.60/kW-Month) and accelerates at 2% percent year over year. Energy arbitrage opportunities increase year over year by 5% to account for volatility in energy market. Transmission costs are estimated to increase 4% each year, and the battery will be able to achieve a reduction of peak load of 80% of the nameplate capacity (with a 4% loss in year-over-year ability to reduce peak)



Key Assumptions: Low Case scenario: Member-connected behind-the-meter-BESS, MISO's PY25/26 DLOL Capacity Accreditation estimates applied to the first year with decreasing accreditation each year thereafter. Capacity pricing for PY2027-28 starts at annualized $120/MW-Day (or $3.65/kW-Month) and accelerates at 3% percent year over year. Energy arbitrage opportunities increase year over year by 2% to account for volatility in energy market. Transmission costs estimated to increase 2% each year, with an initial year peak load reduction of 60% of the nameplate capacity (with a 1% loss in year over year ability to reduce peak).



Conclusion: For MISO member-connected 4-hour BESS, the projected revenue from the RTO is between \$12.00/KW-Month and \$15/KW-Month. For a beneficial addition to IMEA portfolio, an Energy Storage Service Agreement should be as close to \$13.00/KW-Month as possible.

4.6 Financial Analysis - GDS Associates, Inc.

IMEA sought the input of an independent third party for financial analysis. This report prepared by GDS Associates, Inc. (GDS) "evaluates the lifetime costs and market-driven benefits of lithium-iron-phosphate (LFP) Battery Energy Storage Systems (BESS) for IMEA, with a focus on deployment across the PJM and MISO markets". Lithium-iron-phosphate (LFP) is a type of lithium-ion battery. GDS made slightly different assumptions than IMEA about capacity pricing in PJM and MISO, but conclusions are largely the same. The GDS report then "outlines key value streams to present a comprehensive cost-benefit framework to guide future battery additions into IMEA portfolio." The GDS executive summary is included in this section, and the full report is included in appendix 6.4.

4.6.1 Cost Modeling Overview

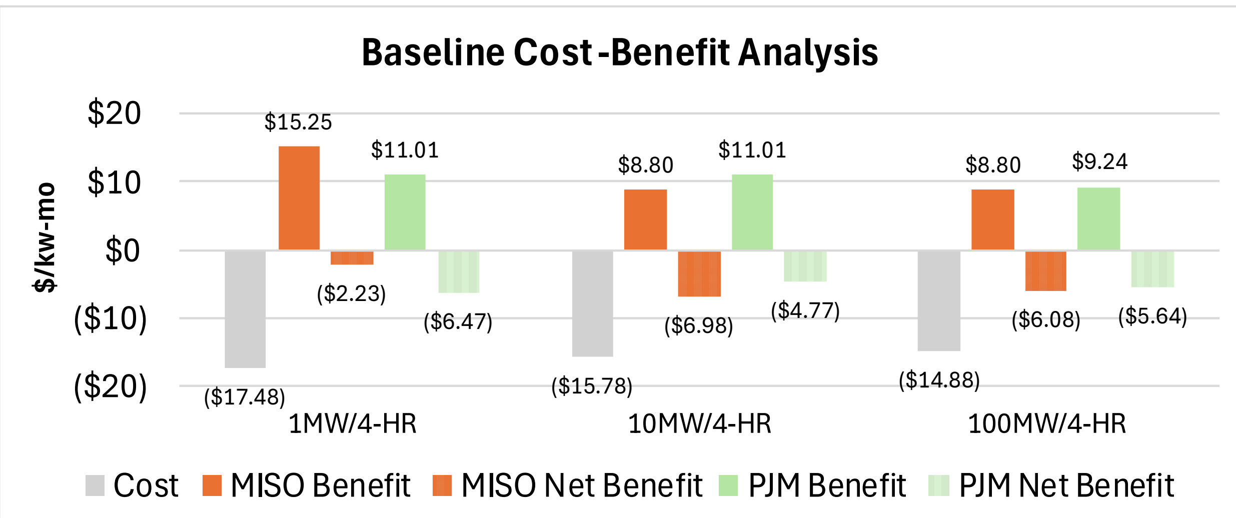
Baseline cost estimates for 4-hour duration configurations over twenty years are as follows: 1 MW $17.48/kW-month, 10 MW: $15.78/kW-month, 100 MW: $14.88/kW-month.

4.6.2 Benefit Modeling Insights

IMEA's geographic footprint spans both PJM and MISO, enabling access to similar value streams in each market. While both offer capacity, transmission, and arbitrage opportunities, PJM provides additional revenue potential through its mature Ancillary Services Market. MISO's ancillary services are still under development and was excluded from this analysis. Market baseline average benefits are different for 1MW versus 10MW and 100MW due to Transmission Service savings being applicable to sizes less than 5MW in MISO and less than 10MW in PJM. The benefits in MISO are $15.25/kw-mo for 1MW scenario and $8.80/kw-mo for the 10MW and 100MW scenarios. The benefits in PJM are $11.01/kw-mo for 1MW and 10MW scenario and $9.24/kw-mo for the 100MW scenario.

4.6.3 Key Conclusions

Net benefits under modeled cost structure for third-party ownership model do not produce an economically feasible scenario using baseline assumptions[53]. The lowest possible cost of BESS (~$11/kw-mo), or alternative contractual structures such as shared savings agreements, will need to be achieved to make a project feasible in either Market. IMEA may also explore the option of public power ownership, leverage municipal debt financing and reduce developer margins. GDS concludes that a unit size that captures Transmission Service Cost avoidance has the greatest potential to yield favorable economic returns (<5MW in MISO). PJM may also introduce transmission service charge reduction limits; therefore, PJM scenarios transmission charges avoidance was limited to 10MW.). Larger unit sizes (10+MW) or multiple deployments of smaller units (1MW) may also support better pricing due to equipment procurement economies of scale.



Baseline assumptions: 20-year evaluation period, 30% ITC, 20% Tariff on < 55% of the equipment CAPEX, 0% discount rate, 10% developer margin on CAPEX/FOM over term, Chicago metro regional cost factor, moderate capacity and transmission benefit scenarios, arbitrage value based upon regional historic LMPs, $1.00/kw-mo PJM Ancillary service value without escalation, developer financing rate of 8.5%, 2% inflation rate on O&M, 95% availability guaranty, 20-year energy capacity warranty, 85% efficiency.

Chapter 5 Recommendations

5.1 Recommendation

Economic feasibility

Despite the cost and regulatory uncertainties, IMEA staff recommend proceeding with a pilot behind-the-meter BESS in member municipalities for the Agency and its members to gain valuable experience in a resource that is likely to become a significant asset to any utility's portfolio. This includes selecting a member site that is economically advantageous, issuing a vendor RFP, and determining the cost impacts of adding a pilot BESS. The vendor RFP results will provide additional details for the full cost and benefit impact.

Based on current technology costs, state policy, and projected market revenues, a carefully structured pilot project will be a strategic addition to IMEA, even if it may not be fully economically justified. While uncertainty remains among input prices, future RTO accreditation, and evolving market rules, the declining cost curve of lithium-ion and the potential to take advantage of multiple revenue streams (capacity, energy arbitrage, load netting) support a foray into the technology.

Recommendation

IMEA should pursue a utility-scale, behind-the-meter pilot project between 1 and 5 MW, designed for a 4-hour discharge duration. The size range is needed to determine the economies of scale and could be further narrowed based on the ability of the applicable member's distribution grid. This size allows for meaningful market participation, provides operational value through various sources such as load netting, energy arbitrage, and capacity accreditation, while simultaneously limiting exposure to financial and technical risks.

Any project undertaken must remain contingent upon two factors: favorable pricing and clear member interest. A key factor in the recommendation is the value of gaining operational and contractual experience in a resource whose use is projected to expand rapidly in the near future. Member engagement is equally important, as host municipalities will play a key role in site selection, interconnection, and coordination with local authorities.

The pilot project should also play out across IMEA's footprint. IMEA's membership includes communities served by both PJM and MISO, and differences in market rules, capacity accreditation, and operational practices make it prudent to test BESS performance in both regions. The recommendation is to pursue one BESS in a PJM-served member municipality and another in a MISO-served member municipality. This approach enables IMEA to compare outcomes directly, share benefits among members, and establish a more comprehensive understanding of the role of BESS in each RTO. IMEA will continue to advance our Agency net-zero goals. As IMEA pursues this pilot project, the Agency will incorporate member feedback to best inform any subsequent iterations of an RFP and future plans.

5.2 Review

This study began by outlining the impetus for studying BESS. IMEA faces a changing resource landscape. The retirement of dispatchable generation and surging demand from electrification and data centers has coincided with the rise of intermittent generation resources that are inherently weather dependent. These shifts have created reliability challenges and have underscored the need for resources that can provide flexibility and dependability. In addition, Illinois state policy is accelerating the move toward carbon-free energy and elevating the importance of BESS as a potential tool in ensuring reliability.

The report then introduced the fundamentals of BESS. It described how batteries work, with an emphasis on lithium-ion technology, which is the predominant chemistry in BESS. While emerging chemistries such as vanadium redox flow and solid-state alternatives may become competitive in the future, lithium-ion systems currently provide the best combination of cost, performance, and commercial availability. The study also discussed key performance characteristics, while highlighting the convention of 4-hour systems capable of participating effectively in RTO markets.

Safety considerations were focused on next. Lithium-ion BESS present risks, most notably thermal runaway, which can cause fires that are difficult to extinguish. Toxic gas emissions are an additional concern. However, mitigation strategies have advanced significantly, and systems now integrate sophisticated monitoring, automated shutdowns, fire suppression technologies, and coordinated emergency response planning. Effective integration of BESS requires early and ongoing engagement with local fire departments and first responders, ensuring clear protocols are in place before commercial operation.

The cost and benefit analysis weighed both economic and strategic value. On the cost side, capital expenditures for lithium-ion batteries have declined sharply over the last decade, making BESS more attainable. Operating costs, although not negligible, are predictable and largely driven by monitoring and safety. On the benefit side, BESS offers multiple value streams including load netting, energy arbitrage and capacity accreditation. The study compared different ownership structures, including IMEA-owned systems and third-party ESSAs, and found that while each has tradeoffs, an ESSA is the avenue best suited for IMEA at the moment.

From a strategic perspective, BESS aligns closely with IMEA's Sustainability Plan and goals, as well as its broader mission to deliver reliable and affordable power. Importantly, the analysis determines that a utility-scale behind-the-meter BESS strikes the balance between meaningful impact and manageable exposure. Such an approach facilitates operational experience without requiring intensive capital commitments.

Finally, the study emphasizes that a measured approach is prudent. Beginning with a pilot project allows IMEA to build institutional knowledge on a resource that is primed to continue to grow in importance in the coming years. Lessons learned will guide the expansion into additional BESS in the years ahead. This incremental path manages risk while ensuring IMEA remains proactive in adapting to industry change.

5.2.1 Future Steps and Proposed Timeline

Step	Action*	Responsible Party	Target Date
1	Staff generates member RFP	IMEA Staff	March 2026
2	Issue member RFP for host sites	IMEA Staff	April 2026
3	Members respond to IMEA	IMEA Members	June 2026
4	Board selects member host sites	IMEA Board	Oct 2026
5	Board approves developer RFP	IMEA Staff + Members	Oct 2026
6	Issue developer RFP	IMEA Staff	Oct 2026
7	Board approves developer selection	IMEA Board	Feb 2027
8	Contract negotiations	IMEA Staff + Developer	Feb-Aug 2027
9	Contract approval	IMEA Board	Oct 2027
10	Project(s) online	IMEA + Host Member	2028/2029

*All actions are tentative upon Board approval and dependent on Member RFP results

Chapter 6 Appendices

6.1 IMEA DOE Designated Energy Communities

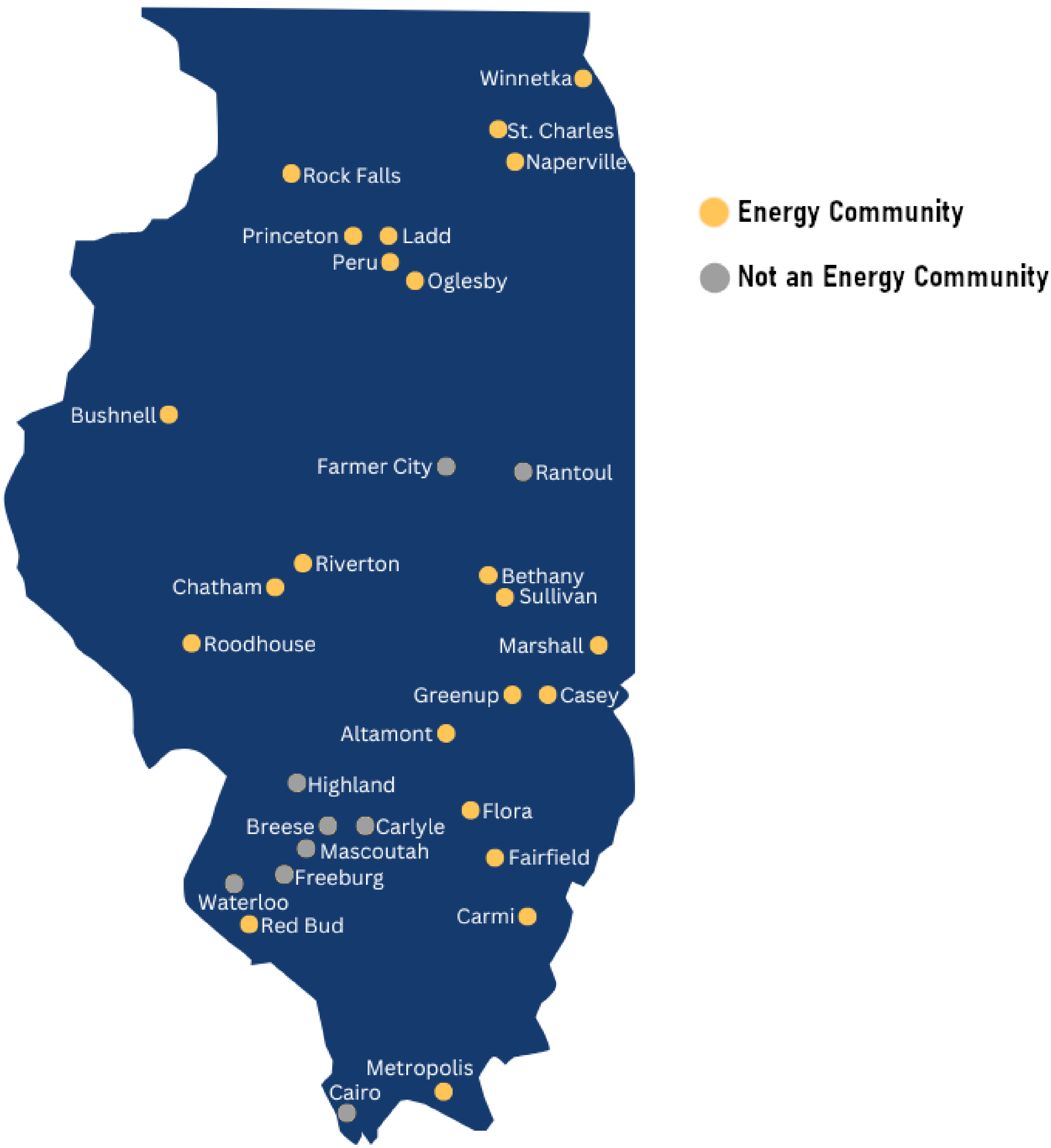
IMEA Member Community	RTO	Energy Community - Coal Closure - 2024	Energy Community - Fossil Fuel Employment (FFE) and Unemployment Rate - 2024	Subject to PJM Netting Rules	MISO 5 MVA Limit Reached	NOT an Energy Community in 2024 - Only Meets FFE**
Naperville	PJM	No	Yes	Yes	N/A	N/A
St. Charles	PJM	No	Yes	Yes	N/A	N/A
Rock Falls	PJM	No	Yes	Yes	N/A	N/A
Winnetka	PJM	No	Yes	Yes	N/A	N/A
Princeton	MISO	Partial*	Yes	N/A	Yes	N/A
Peru	MISO	No	Yes	N/A	Yes	N/A
Ladd	MISO	Partial*	Yes	N/A	No	N/A
Oglesby	MISO	Partial*	Yes	N/A	No	N/A
Bushnell	MISO	Partial*	Yes	N/A	Yes	N/A
Farmer City	MISO	No	No	N/A	Yes	No
Rantoul	MISO	Partial*	No	N/A	Yes	No
Riverton	MISO	No	Yes	N/A	No	N/A
Chatham	MISO	Partial*	Yes	N/A	No	N/A
Bethany	MISO	No	Yes	N/A	No	N/A
Sullivan	MISO	No	Yes	N/A	Yes	N/A
Marshall	MISO	Partial*	Yes	N/A	Yes	N/A
Roodhouse	MISO	No	Yes	N/A	No	N/A
Greenup	MISO	No	Yes	N/A	No	N/A
Casey	MISO	No	Yes	N/A	Yes	N/A
Altamont	MISO	No	Yes	N/A	Yes	N/A
Highland	MISO	No	No	N/A	Yes	Yes
Breese	MISO	No	No	N/A	Yes	Yes
Carlyle	MISO	No	No	N/A	Yes	Yes
Flora	MISO	No	Yes	N/A	Yes	N/A
Mascoutah	MISO	Partial*	No	N/A	No	Yes
Freeburg	MISO	No	No	N/A	Yes	Yes
Fairfield	MISO	No	Yes	N/A	No	N/A
Waterloo	MISO	Partial*	No	N/A	Yes	Yes
Red Bud	MISO	Yes	Yes	N/A	Yes	N/A
Carmi	MISO	Yes	Yes	N/A	Yes	N/A
Metropolis	MISO	Yes	Yes	N/A	No	N/A
Cairo	MISO	No	No	N/A	No	No

*Partial means there are Census Tracts nearby that qualify

**They meet Fossil Fuel Employment (FFE) threshold Only, are not an Energy Community as of June 7, 2024 because they didn't meet Unemployment Rate requirement for the year

6.2 IMEA Energy Community Map

IMEA Member Communities with Energy Community status (as of 6/7/24)



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A full copy of the report prepared by GDS Associates, Inc. has been provided. The assumptions of GDS Associates are slightly different than IMEA. GDS Associates is a full-service electric utility consulting firm based in Marietta, GA, with offices throughout the country. They specialize in grid solutions in power supply, transmission, distribution, energy use and efficiency, as well as rates and compliance.

6.4 Full Draft GDS Associates Report

PREPARED BY GDS ASSOCIATES, INC.

IMEA
IMUA
IPEA

Illinois Municipal Electric Agency

BESS Cost-Benefit Model Report

March 2, 2026

CONTENTS

FIGURES

1 Executive Summary

This report evaluates the lifetime costs and market-driven benefits of lithium-iron-phosphate (LFP) Battery Energy Storage Systems (BESS) for IMEA, with a focus on deployment across the PJM and MISO markets. It outlines key value streams to present a comprehensive cost-benefit framework to guide future battery additions into IMEA portfolio.

Cost Modeling Overview

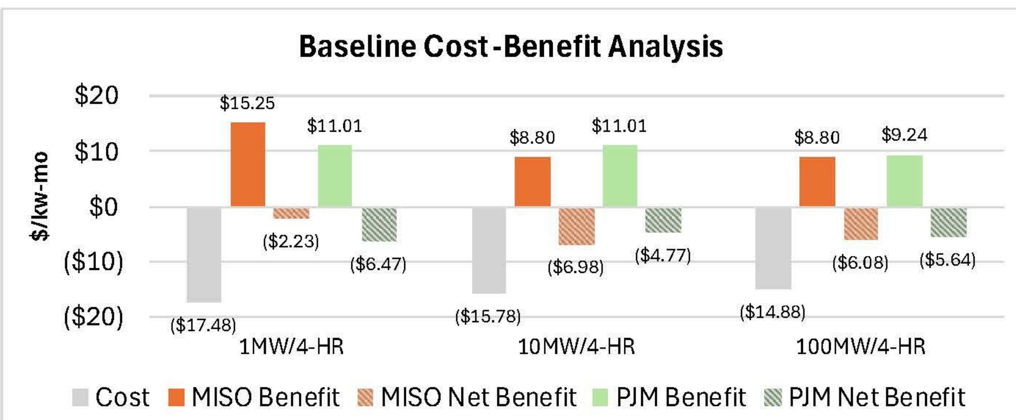
Baseline cost estimates for 4-hour duration configurations over twenty years are as follows: 1 MW $17.48/kW-month, 10 MW: $15.78/kW-month, 100 MW: $14.88/kW-month.

Benefit Modeling Insights

IMEA's geographic footprint spans both PJM and MISO, enabling access to similar value streams in each market. While both offer capacity, transmission, and arbitrage opportunities, PJM provides additional revenue potential through its mature Ancillary Services Market. MISO's ancillary services are still under development and was excluded from this analysis. Market baseline average benefits are different for 1MW versus 10MW and 100MW due to Transmission Service savings being applicable to sizes less than 5MW in MISO and less than 10MW in PJM. The benefits in MISO are $15.25/kw-mo for 1MW scenario and $8.80/kw-mo for the 10MW and 100MW scenarios. The benefits in PJM are $11.01/kw-mo for 1MW and 10MW scenario and $9.24/kw-mo for the 100MW scenario.

Key Conclusions

Net benefits under modeled cost structure for third-party ownership model do not produce an economically feasible scenario using baseline assumptions[1]. The lowest possible cost of BESS (~$11/kw-mo), or alternative contractual structures such as shared savings agreements, will need to be achieved to make a project feasible in either Market. IMEA may also explore the option of public power ownership, leverage municipal debt financing and reduce developer margins. GDS concludes that a unit size that captures Transmission Service Cost avoidance has the greatest potential to yield favorable economic returns (<5MW in MISO). PJM may also introduce transmission service charge reduction limits; therefore, PJM scenarios transmission charges avoidance was limited to 10MW.). Larger unit sizes (10+MW) or multiple deployments of smaller units (1MW) may also support better pricing due to equipment procurement economies of scale.



[1] Baseline assumptions: 20-year evaluation period, 30% ITC, 20% Tariff on < 55% of the equipment CAPEX, 0% discount rate, 10% developer margin on CAPEX/FOM over term, Chicago metro regional cost factor, moderate capacity and transmission benefit scenarios, arbitrage value based upon regional historic LMPs, $1.00/kw-mo PJM Ancillary service value without escalation, developer financing rate of 8.5%, 2% inflation rate on O&M, 95% availability guaranty, 20-year energy capacity warranty, 85% efficiency.

2 Cost Drivers

BESS cost analysis in this report projects proforma from cradle to grave which provides IMEA specific results based on the specific case outlined. Many municipal asset owners and operators are gaining experience with managing the health of large-scale batteries through the proper procurement and third-party management of battery operations. Developers are deploying an increasing variety of energy storage projects in large numbers and have operational synergies between projects. The costs of operating an energy storage system depend on who owns it and how it is used as systems are typically designed to provide a planned number of cycles over a specific service life. Asset owners and operators must be able to manage the long-term health of their assets given proforma expectation. This report does not recommend an ownership path but does provide expected lifetime costs under multiple battery sizes, while the baseline cost-benefit analysis utilizes the most likely scenario for feasible energy storage deployment.

2.1 CAPITAL EXPENDITURE (CAPEX)

To estimate the current capital cost of energy storage systems, GDS uses a structured methodology which involves gathering publicly available Integrated Resource Plans (IRPs) and periodic industry publications. IRPs, typically released by utilities and regional transmission organizations, provide detailed projections of future resource investments, including cost assumptions for BESS. GDS analysts extract relevant cost data—such as $/kW or $/kWh figures—from these documents, often segmented by technology type, installation scale, and regional factors. Complementing this, periodic publications from government agencies, research institutions, and market analysts (e.g., NREL, EIA, BloombergNEF, Lazard, etc.)[2] offer updated benchmarks and trend analyses. By synthesizing data across multiple sources and normalizing for inflation, geography, and system configuration, a robust and current estimate of capital costs is derived to inform financial modeling.

2.1.1. Power and Energy System Sizing

The nameplate power of a BESS refers to the rate at which it can deliver or absorb energy, measured in kilowatts (kW) or megawatts (MW), and determines its interconnection characteristics. Energy capacity, measured in kilowatt-hours (kWh) or megawatt-hours (MWh), defines how long the system can sustain that power output. Choosing the right power and energy ratings depends on how you plan to use the system, such as for fast frequency response, load shifting, backup power, or smoothing out renewable energy supply. A BESS for frequency regulation needs high power and low energy, while one for load shifting requires large energy capacity for long discharge. Proper sizing ensures optimal performance, economic viability, and compliance with operational demands. Using accurate power and energy characteristics is essential for modelling costs and serves as an input to the BESS cost calculation.

2.1.1.1 Energy

In both PJM and MISO, a 4-hour BESS strikes the ideal balance between performance and economic value. PJM's capacity market rules require resources to sustain output for at least four continuous hours to qualify for full capacity accreditation, making 4-hour systems the minimum threshold for maximizing revenue from capacity payments. Similarly, MISO's evolving modeling and performance standards increasingly favor longer-duration storage to support grid stability, particularly under stressed conditions or during peak load events. From a transmission and congestion relief perspective, 4-hour systems offer sufficient flexibility to shift energy across critical hours, enhancing reliability and reducing curtailment. While shorter-duration systems may suffice for fast-response ancillary services, they fall short in capturing the full spectrum of value streams available in these markets. Thus, 4-hour BESS configurations are emerging as the most versatile and financially viable choice for developers and asset owners operating in PJM and MISO.

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[2] Links to relevant data resource: EIA Capital Cost Report, EIA AEO Report, Lazard LCOE Report, NREL ATB Report, PNNL Energy Storage Database

2.1.1.2 Power

Larger BESS installations, particularly those greater than 100 MW benefit significantly from economies of scale, reducing per-MW CAPEX and improving overall project economics compared to smaller 1 MW or 10 MW systems. When BESS projects grow from 1 MW to 100 MW, fixed expenses like engineering, permitting, interconnection, and site development are distributed across more capacity. This distribution reduces the average cost per megawatt. According to recent cost analyses[2], utility-scale BESS CAPEX has dropped sharply in recent years, with larger systems achieving more favorable pricing on equipment procurement, installation, and integration. Regulatory flexibility, particularly in distribution-connected systems, often results in missed opportunities for bulk purchasing discounts and optimized operational efficiencies. However, at the 10MW scale, certain advantages begin to emerge. While opportunities exist before reaching the 100 MW scale, it is at this threshold that developers can maximize the benefits of standardized designs, modular construction, and efficient coordination. These factors help reduce initial expenses. These advantages not only lower upfront costs but also enhance long-term returns through better performance and reduced maintenance overhead.

A basic assumption (see Figure 1) serves as the foundation for calculating a comprehensive system CAPEX, reflecting what IMEA would acquire via either third-party development or an EPC contract. The CAPEX presented here is based on this approach. The CAPEX used in this analysis begins with this base CAPEX and further applies cost sensitivities associated with tariffs, ITC, and developer margins.

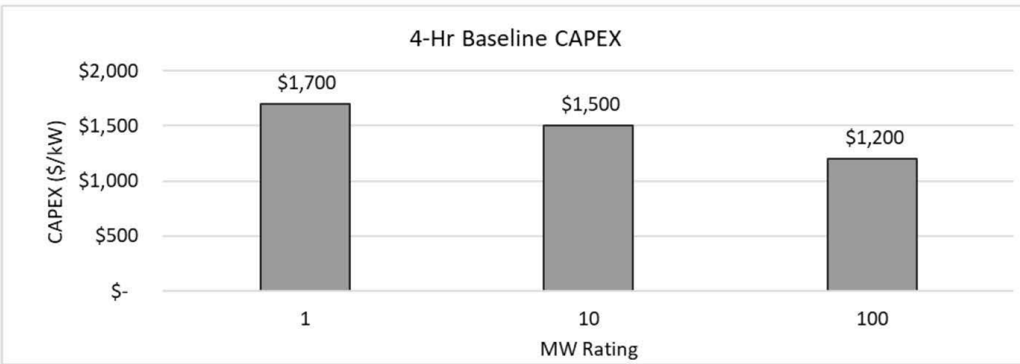


FIGURE 1 - BASE ASSUMPTION FOR 4-HOUR BESS CAPEX

2.1.2. Interconnection

Distribution-interconnected BESS assets in the 1–10 MW range offer notable interconnection cost advantages compared to larger, transmission-interconnected systems. These smaller-scale projects typically face fewer regulatory hurdles, shorter permitting timelines, and lower interconnection costs, making them more attractive for rapid deployment and localized grid support. In contrast, transmission-level interconnections often trigger more complex studies, longer queues, and substantial upgrade requirements, which can add an estimated $2–$5/kW-month to overall project costs. Due to the unpredictable and location-dependent nature of these costs, a rate of $1 per kW-month was used for distribution-connected systems, whereas $3 per kW-month was applied for transmission-interconnected projects with a capacity of 100 MW.

2.1.3. Site Specific Costs

Development of the selected site will facilitate decisions on various best practices to achieve technical specifications for a construction firm to complete civil design scope. This process results in a specification for contractors to implement designs based upon physical constraints, equipment specifications, substation integration analysis, system impact studies, operation and maintenance planning, integration with utility operations, applicable codes and standards, community and environmental impacts, site access, and utility preferences. Compact and standardized designs, such as containerized LFP systems, often benefit from economies of scale, streamlined installation, and reduced labor, lowering both capital and operational expenses. In contrast, custom or large-scale stationary systems may require specialized engineering, site preparation, and interconnection efforts, driving up costs. The physical footprint also affects land use and permitting complexity, especially in urban or space-constrained environments. Additionally, the site influences thermal management, accessibility for maintenance, and scalability, all of which contribute to long-term cost efficiency. Choosing the right site is therefore a strategic decision that balances technical performance with financial viability. Base CAPEX estimates rely on standard site-specific costs, but accurate project estimates may need several subject matter experts to examine site details and assess expenses. Site costs in the BESS cost estimation have typical user assumptions. The term "typical" implies that predevelopment has occurred and has been evaluated as being below average.

2.1.4. Owner's Costs

Owner's costs encompass a range of expenditures beyond direct construction and equipment procurement. These costs include project development expenses such as permitting, interconnection studies, environmental assessments, and legal and technical advisory services. Owners must also account for land acquisition or leasing, system integration upgrades, and construction insurance premiums. During the pre-construction phase, costs related to engineering design, stakeholder engagement, and project management are significant. Additionally, contingency reserves are often built into budgets to cover unforeseen delays or regulatory changes. These owner-incurred costs are critical to accurately estimating total project investment and ensuring the long-term viability and bankability of the BESS asset. Typical owners' costs are structured into the base CAPEX estimates provided in this report.

2.1.5. Public Power BESS Ownership

BESS are no longer considered an emerging technology because of the large-scale deployment of LFP-based battery storage across the United States. Battery manufacturing global expansion combined with Investment Tax Credits (ITC) have created alternatives for IMEA to procure BESS as an economical resource in their power supply portfolio. Public Power has historically contracted with third-party owners and operators through an Energy Storage Service Agreement (ESSA), which provides utilities access to the equipment without the liability of ownership. The need for ESSA's has been driven by third-party development and operations experience along with life cycle management of expected performance and decommissioning responsibilities. Technology maturation and the ability for Public Power to capture the ITC through Elective Pay[3] has created opportunities for utilities to develop, own, and operate BESS facilities.

Direct-Purchase and Build-Transfer Agreements (BTA) are becoming viable options for utility-owned and operated BESS facilities. The complexities associated with owning and managing Distributed Energy Resources (DER) are considerable, and numerous municipal utilities may lack the immediate capacity to incorporate a technology with which they have limited familiarity. Asset ownership covers financing options, expert support, incentive capture, internal capability development, and project performance management. An organization seeking to obtain the benefits of BESS ownership while overcoming the challenges should be aware of the following:

Challenges

- **Installation Costs:** dependent on ability to finance and manage credit impacts
- **Engineering and Construction:** Contracting qualified construction firms and managing projects
- **Operations Staffing:** Develop local expertise to execute operations and maintenance
- **Asset Management:** Attain effective asset management and warranty issues
- **Reliability Events:** Manage reliability including catastrophic events or equipment failures
- **Capturing Incentives:** Navigate ITC's Prevailing Wage and Domestic Content Requirements
- **Supply Chain:** Achieve price certainty in the age of tariffs and Developer consolidation

Benefits

- **Economic Margins:** Control of the procurement process while offsetting Developer margins
- **Cost of Capital:** lower cost of capital as compared to Developers

[3] https://home.treasury.gov/system/files/8861/ITC%20Elective%20Pay%20Explainer%20vF%201224_0.pdf

- **Strategic Benefits:** Develop organizational staff capability and project engagement
- **Mature Industry:** Peripheral services available such as liability insurance and warranty support
- **Utility Procurement:** Create strategic relationships with supply chain and project partners
- **Flexibility of Operations:** Economic opportunities may shift over the 20+ year useful life

Project execution steps vary on a case-by-case basis but always involves the hurdles of: (1) early-stage development, (2) obtaining project capital / financing, (3) selecting project partners, and (4) assuring Operation and Maintenance (O&M) throughout the life of the equipment. Utilities generally understand how to manage distribution systems and substations, but BESS remains unfamiliar as it is a newer addition to their DER portfolios. IMEA's organizational capabilities and project partners will determine the ability to support the various aspects of BESS asset ownership.

Choosing to add energy storage brings lasting consequences, regardless of whether the asset belongs to a utility or a developer. Every utility has their own challenges that determine the most economical and comprehensive solution. Certain entities are skilled at managing and owning power generation assets, whereas other utilities have expertise primarily in operating the electric distribution system. Although BESS is far less complex than an aeroderivative turbine and other utility managed assets, IMEA will need to carefully evaluate the ability to support the project throughout its lifecycle. Diligence should be completed with respect to obtaining capital financing, reviewing internal capabilities, and seeking out third-party services that allow them to successfully execute the project plan.

Not every utility is equipped to explore all aspects of owning and operating BESS, but there may be some key areas that allow the utility to create opportunities from within and grow. For example, the electric utility typically has a detailed understanding of its electric distribution system and substations to integrate the BESS into their system with the correct protection and controls. Once an evaluation of organizational capabilities is complete the utility can seek out support services from known project partners and other third-parties to assure project success.

Third-party services are widely available to help assure project success while utilities eventually scale up operations during construction and over the life of the project. Some of these services include outside assistance for legal and regulatory compliance, market analysis and integration, communication and data management, financial consulting, technical consulting, information technology, operational and maintenance, and general asset management support.

2.2 FIXED OPERATION AND MAINTENANCE

Fixed Operation and Maintenance (FOM) costs for BESS represent the predictable, recurring expenses required to keep the system functioning efficiently over its lifespan. The cost rates in the BESS cost include routine inspections, software updates, thermal management system maintenance, safety system checks, warranty services, insurance, and labor for scheduled servicing. Unlike variable costs that fluctuate with usage, FOM expenses are incurred regardless of how often the system is cycled, making it essential for accurate financial modeling. FOM also covers administrative overhead, remote monitoring, and compliance with regulatory standards. Properly estimating FOM ensures long-term reliability, minimizes downtime, and supports warranty and performance guarantee obligations.

2.3 GUARANTEES AND INSURANCE

Performance guarantees in energy storage agreements often come with significant cost implications, as they shift technical and financial risk from the Buyer to the Seller. These guarantees typically cover metrics like system availability, round-trip efficiency, energy capacity retention, and response time over the contract term. To uphold these commitments, Sellers may need to invest in higher-quality components, more robust system design, and ongoing maintenance, all of which increase upfront and operational costs. Additionally, the inclusion of liquidated damages or penalties for underperformance can drive up the price of the agreement, as Seller's factor in risk premiums. While performance guarantees offer buyers greater confidence in system reliability and ROI, they must be carefully balanced against the total cost of ownership and the complexity of enforcement mechanisms. For these reasons, typical performance guarantees including a 95% availability guaranty, 85% round trip efficiency (RTE) guaranty and a 4-hour energy capacity guaranty over the term are used in the BESS cost estimation.

Insuring BESS can be a complex and costly endeavor due to the unique risks associated with this high capital investment and operational uncertainties. Premiums are influenced by factors such as system size, chemistry (e.g., LFP vs. flow batteries), location, fire risk, and integration with other grid assets. Insurers may require detailed engineering assessments, fire suppression systems, and performance guarantees before underwriting coverage. Costs typically include property insurance for physical damage, liability coverage for third-party harm, and business interruption insurance to protect against revenue loss during outages. As BESS deployments scale and historical performance data improves, insurance markets are gradually adapting, but coverage remains more expensive and restrictive compared to traditional energy assets. BESS cost estimation includes these costs; however, an Insurance SME should evaluate project-specific risks to ensure that appropriate insurance costs are accounted for.

2.3.1. Degradation

Managing energy capacity and battery degradation remains crucial for many projects to ensure the anticipated useful life. Battery supply contracts often involve energy capacity guarantees which are linked through metrics such as annual MWh throughput or the average state of charge. The guaranties are typically based on use-case assumptions as degradation is a function of depth of discharge, power rate, battery temperature, and average state of charge. The depth of discharge is typically the most impactful variable although other limitations are observed in battery operation to deter degradation. The BESS cost estimation applies a degradation rate based on the number of annual cycles that the use-case demands. For purposes of transmission and capacity use-cases, a base of 200 cycles per year are assumed. Ancillary services may require approximately 100 additional cycles per year which impacts degradation, so the value assumption for PJM Regulation D service will be net of that cycling cost for simplicity purposes[4].

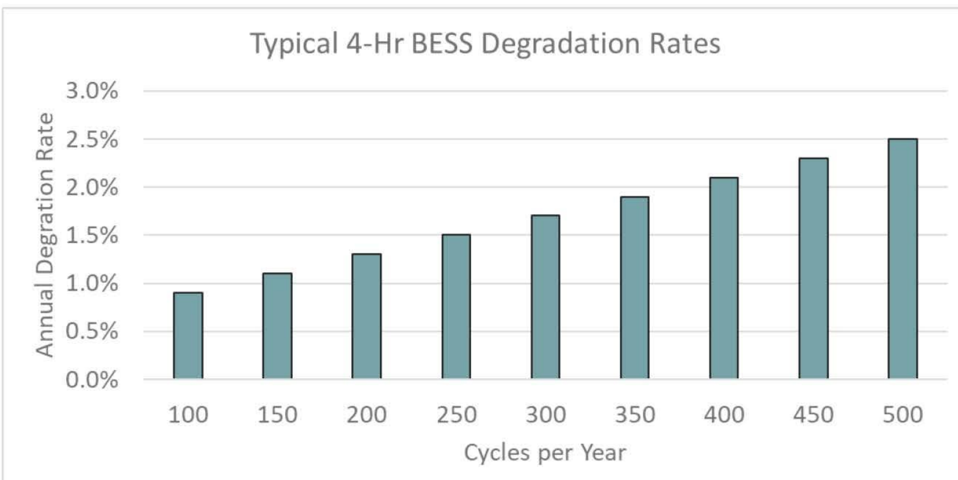


FIGURE 2 - ANNUAL DEGRADATION RATES

2.4 VARIABLE OPERATIONS & MAINTENANCE

GDS considers the following cost categories when translating the underlying technical cost drivers into a cost recovery or planning cost framework to be used by market systems. A battery system's degradation rate affects variable operation and maintenance (VOM) costs through increased maintenance intervals, battery pack augmentation, and unplanned increased end-of-life costs. Our approach is to characterize a use-case strategy using use-case's effect on degradation and then place that alongside other battery economics components.

[4] Internal analyses over multiple PJM ancillary service projects.

The total VOM and the corresponding use-case strategy are most effectively modeled when all related equipment lifecycle management impacts are considered. GDS dynamically weighs the cost components into VOM analyses. It may generally be assumed that VOM costs, excluding any capital investment dollars, from greatest to least are:

1. Charging Energy
2. Degradation
3. Auxiliary Load
4. Premature Failures and End of Life Schedule Shifts

2.4.1. Round Trip Efficiency

The cost of buying energy from the grid is usually the largest component of a cycle's VOM, where parasitic losses and round-trip efficiencies are variable based on the use-case. Round trip efficiency guarantees provide assurance that a system can perform as expected and VOM remains predictable. Efficiency typically decreases over life, which can be accounted for in VOM analysis related to charging energy purchases. The BESS cost estimation uses 87%, declining at 0.15% annually, for an RTE number which is defined as the total energy output divided by the total energy input over a single duty cycle.

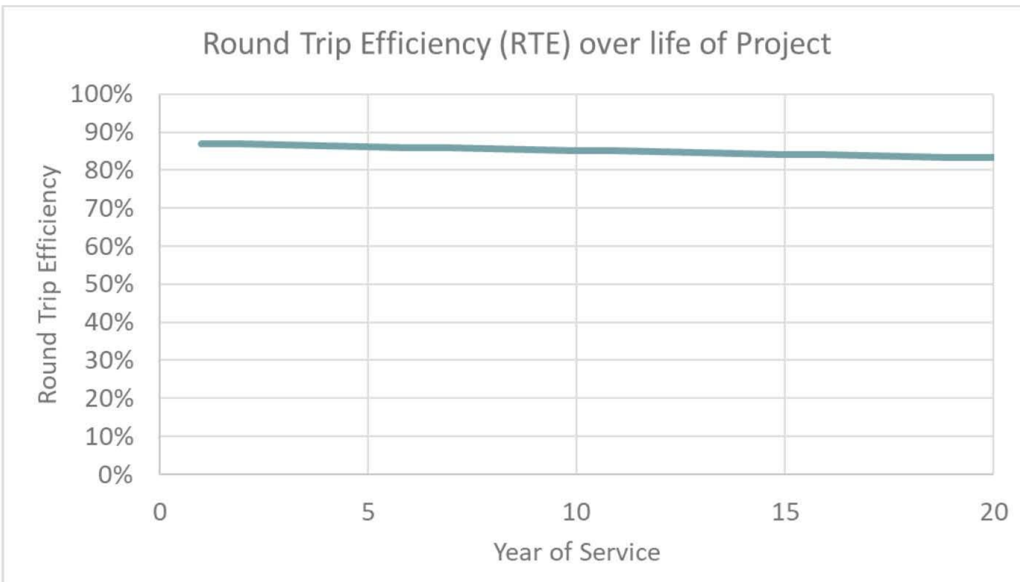


FIGURE 3 - TYPICAL ROUND-TRIP EFFICIENCY OF A 4-HOUR BESS

2.4.2. Auxiliary Load

The overall efficiency strongly depends on auxiliary loads when the system is in stand-by mode, versus RTE as previously described which is the efficiency of a duty cycle. The thermal management system and other auxiliary components draw substantial auxiliary power when the system is idle. These variable costs are dependent on the amount of idle time between cycling where the BESS cost estimation will apply an efficiency loss rate to the total annual idle time based upon the form factor of the system. Auxiliary loads range given climate, form factor, and battery technology but are modeled at 1.5 kWHr per MW of 4-hour BESS. i.e.) – a 10 MW / 40 MWHr system idle for 24 hours is modeled to consume 360 kWHr (1.5*10*24=360 kWHr). The auxiliary load and RTE losses and compiled to give an "all-in" efficiency number in performance summary tables which is based upon LMP curves (Figure 12 and Figure 13) assumed for this study. Figure 4 illustrates examples of these variable costs assumed in the BESS cost estimation for 1MW, 10MW, and 100MW scenarios.

Project Efficiency Metrics	1MW	10MW	100MW	Units
Charging Energy	1444	14101	141011	MWHr/Year
Discharge Energy	1200	12000	120000	MWHr/Year
Auxiliary Load	6	93	932	MWHr/Year
All-In Annual Efficiency	83%	85%	85%	% Year 1
All-In Annual Efficiency	$12,480	$109,710	$1,097,104	$ Year 1

FIGURE 4 - EFFICIENCY METRICS BASED UPON 200 CYCLES/YEAR

2.4.3. Operational Risks

Battery systems are generally designed for a useful lifespan of twenty years, and longer-term contracts are becoming financially feasible as lenders gain greater confidence. There are numerous subsystems in the BESS which may require repair or replacement, such as replacing HVAC units or inverter overhauls. The expected lifespan of each subsystem may change depending on how long it operates. As a result, decisions about repairing or replacing components should be based on the specific use-case and can be assessed during the planning process. Many profiles can materialize over a project's life which may shift these major maintenance schedules and impact the variable costs. SME influenced sensitivity analyses may incorporate worst case scenarios of owning and operating assets to gain further viewpoint of cost risk.

2.5 NERC COMPLIANCE

As the energy landscape undergoes a significant transformation with the growing integration of renewable energy sources, regulatory frameworks are evolving to address new challenges and opportunities. The North American Electric Reliability Corporation (NERC) has introduced updates to its standards concerning inverter-based resources (IBRs) such as solar photovoltaic (PV) systems, wind turbines, and battery storage. These changes reflect the increasing role of IBRs in the grid and aim to ensure continued reliability and stability. NERC's Updated Standards for Inverter-Based Resources:

- NERC Rules of Procedure were updated such that the Generator Owner (GO) and Generator Operator (GOP) registry criteria to include an expanded category of smaller resources, which NERC has labeled Category 2 GOs and Category 2 GOPs. Category 2 GOs/GOPs include non-bulk electric system inverter-based resources that: (i) have nameplate capacity of greater than or equal to 20 MVA and (ii) connected at a voltage greater than or equal to 60 kV.
- MOD / PRC Changes: there are numerous MOD/PRC rule changes that are designed to address IBR dynamic model requirements, adequately supporting grid disturbances, reporting reactive power capability, and collecting the relevant data for analysis. Specifically, changes have been made to MOD-025, 031, and 032, and PRC-002, 019, and 024, along with a handful of other standards.

NERC's updates to standards for inverter-based resources represent a crucial shift in the energy sector. IMEA will need to adapt to these changes to maintain compliance, ensuring operational efficiency, and capitalizing on new opportunities. By investing in advanced technologies, adapting operational strategies, and staying informed about regulatory developments, IMEA can navigate the evolving landscape and position themselves for long-term success.

3 Cost Modeling

Energy storage cost modeling using estimated lifetime costs provides a comprehensive framework for evaluating the true economic value of a system over its operational life. Rather than focusing solely on upfront capital expenditures, this approach incorporates all relevant costs (Figure 5) —including development, construction, and operation —spread across the expected lifespan of the asset. It also accounts for performance metrics such as round-trip efficiency, depth of discharge, and cycle life, which directly influence usable energy and revenue potential. By calculating metrics like levelized cost, stakeholders can compare technologies and configurations on a consistent basis, enabling more informed investment decisions. This holistic view is especially critical for long-duration storage projects, where operational and replacement costs may outweigh initial capital, and for applications with variable revenue streams.

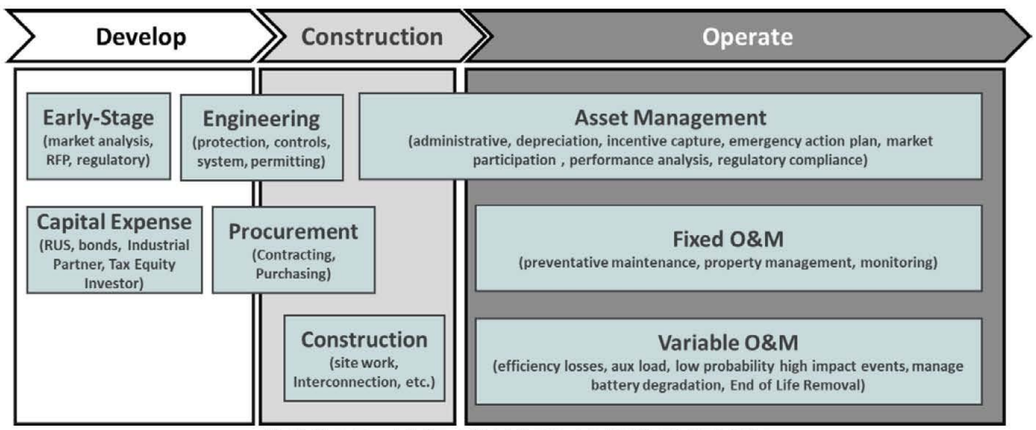


FIGURE 5 - COST ANALYSIS CONSIDERATIONS

1. **Early-stage development:** Owning BESS involves the typical steps of evaluating the value proposition through market and regulatory analyses. The early-stage development process establishes site control, begins the long-term planning process, and determines how the capital expenditure will be financed or otherwise funded.

2. **Capital/ Financing:** Determining how the project's capital cost will be funded is specific to a utility's access to cash through municipal bond financing, Rural Utility Service (RUS) loans, traditional loans, or even having cash on hand. A distinct advantage for municipalities and electric cooperatives is the lower cost of capital relative to Developers, combined with their ability to partner with local industrial or investment entities on upfront capital requirements. Local partners such as data centers, manufacturing facilities, or even community energy programs all have potential to help a utility financially justify the expenditure through electric rate structures or other alternative project structures.

3. **Engineering:** Development of the selected site will facilitate decisions on various best practices to achieve technical specifications for a construction firm to complete civil design scope. This process results in a specification for contractors to implement designs based upon physical constraints, equipment specifications, substation integration analysis, system impact studies, operation and maintenance planning, integration with utility operations, applicable codes and standards, community and environmental impacts, site access, and utility preferences.

4. **Procurement:** Most electric utilities have robust procurement processes in place that are suitable for BESS equipment procurement. To be eligible for the ITC Elective Pay, current Internal Revenue Service guidance requires the project meet Domestic Content thresholds in addition to Prevailing Wages. The accounting of these parameters can be complex and will require tax and accounting skills to advise and manage the process.

5. **Construction:** A general contractor experienced with utility work is typically capable of turning development specifications into detailed design documents outlining the requirements for materials, workmanship, and methods, which ensures consistency and quality. Appropriate staff, including third-party engineers, can advise construction planning and select local companies to execute necessary geotechnical site studies and construction work.

6. **Operations:** BESS facilities are not trivial to manage and require 24/7 monitoring, bi-annual preventative maintenance, and an event response plan. Operations planning translates equipment technical requirements into scheduled maintenance, monitoring strategy, and event response action planning. Utilities can develop best practices to manage operation agreements with third-party O&M provider(s).

7. **Asset Management:** Assuring the economic success of the project comes down to rigorous asset management throughout the life of the project, including construction, operations, and end of life removal. Electric utilities are already familiar with many aspects of managing BESS facilities, such as regulatory compliance, developing emergency action plans, depreciation, managing contractors, product performance analysis, and ensuring employees and public safety. Combining a utility's existing know-how with an experienced third-party vendor will produce an effective asset management team.

3.1 LEVELIZED COST OF ENERGY STORAGE

Levelized cost of energy storage is a financial metric used to evaluate the cost of energy storage systems based on their ability to provide services over the planned useful life. Unlike metrics focused on energy throughput, levelized cost centers on the cost per unit of capacity—expressed in dollars per kilowatt per month ($/kW-month) and accounts for all capital, operational, and maintenance expenses over the system's lifetime. Levelized cost is particularly useful for assessing applications where power delivery, rather than energy duration, is the primary value such as frequency regulation or capacity market participation. Levelizing BESS cost involves dividing the total net present value of the lifetime costs by the cumulative capacity provided, adjusted for degradation and availability. This enables stakeholders to compare different technologies and configurations on a consistent basis, helping guide investment decisions and project development.

3.2 FINANCIAL PARAMETERS

The cost of debt for municipal bonds is primarily the effective interest rate the issuer pays on its borrowed funds, which is equivalent to the bond's yield to maturity (YTM) at the time of issuance. Because the interest on most municipal bonds is exempt from federal income tax (and often state and local taxes), municipalities can borrow at a lower interest rate than corporations or other taxable entities would for comparable debt. The cost of debt for the IMEA owned options detailed in (Appendix A) is 4.8%, which is based upon the current effective federal funds rate[5]. Municipal financing rates vary based on the issuer's creditworthiness, the bond's maturity, and current market conditions, but as of November 2025, rates for highly rated, general obligation municipal bonds are roughly around 4.8% for 20-year maturities. Developers usually finance the project with a mixture of debt and equity. The cost of debt is currently near 8.5%, which was used when estimating the financing costs for developers.

3.3 DEVELOPER MARGINS

To effectively use the BESS cost for evaluating Energy Storage Service Agreement (ESSA) contracts, it is essential to include developer margins to capture the true cost of the agreement. Developer margins serve as a profit cushion that accounts for risks and uncertainties and compensates for the developer's expertise and capital investment.

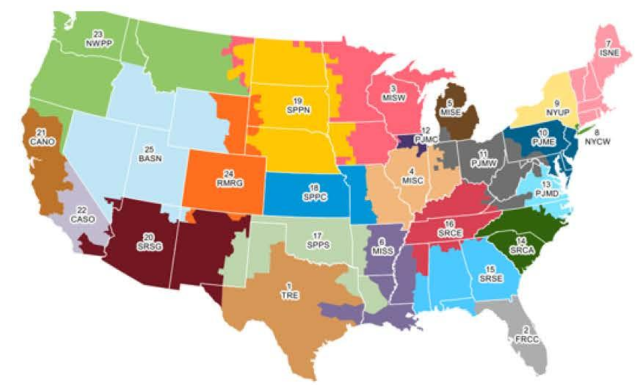
[5] https://www.federalreserve.gov/economy-at-a-glance-policy-rate.htm

3.4 CAPITAL EXPENDITURE

Most analysts anticipate that growth of the overall battery industry across all sectors (consumer electronics, transportation, and the electric utilities) will lead to cost reductions in the long term. In the short term, some analysts expect flat or even increasing pricing based upon shifting policy and supply landscape. Aside from the typical market risks, the growth in the market (effective learning-by-doing) and an increased diversity of support services will expand and change the dynamics of the BESS supply chain, resulting in a higher average annual reduction in scenarios. GDS assumed capital expenditures would occur in 2027 to effectively link current capital expenditures (CAPEX) into the BESS cost.

3.5 REGIONAL TECHNOLOGY COSTS

Regional cost differences in energy storage installations are shaped by a variety of factors including labor rates, permitting processes, grid interconnection requirements, supply chain logistics, and local market maturity. In areas with well-established renewable infrastructure and streamlined regulatory frameworks, such as California, installation costs may be lower due to economies of scale and experienced contractors. Conversely, regions with limited technical expertise, complex permitting, or remote access may face higher costs for engineering, procurement, and construction. Local incentives, land prices, and utility tariffs also play a significant role in shaping total project economics. Additionally, climate conditions can affect system design and cost—for example, installations in hot or humid environments may require enhanced cooling or protective enclosures. Understanding these regional nuances is critical for accurate project CAPEX estimation. The BESS cost employed the Metropolitan Chicago subregion regions represented in (
Figure 6) to inflect the CAPEX and FOM metrics appropriately (for this region it is 106.9%[6]).



Region ID	NERC/ISO subregion	Geographic Name*
1- TRE	Texas Reliability Entity	Texas
2- FRCC	Florida Reliability Coordinating Council	Florida
3- MISW	Midcontinent ISO/West	Upper Mississippi Valley
4- MISC	Midcontinent ISO/Central	Middle Mississippi Valley
5- MISE	Midcontinent ISO/East	Michigan
6- MISS	Midcontinent ISO/South	Mississippi Delta
7- ISNE	NPCC/ New England	New England
8- NYCW	NPCC/NYC & Long Island	Metropolitan New York
9- NYUP	NPCC/Upstate NY	Upstate New York
10- PJME	PJM/East	Mid-Atlantic
11- PJMW	PJM/West	Ohio Valley
12- PJMC	PJM/Commonwealth Edison	Metropolitan Chicago
13- PJMD	PJM/Dominion	Virginia

Region ID	NERC/ISO subregion	Geographic Name*
14- SRCA	SERC Reliability Corporation/East	Carolinas
15- SRSE	SERC Reliability Corporation/Southeast	Southeast
16- SRCE	SERC Reliability Corporation/Central	Tennessee Valley
17- SPPS	Southwest Power Pool/South	Southern Great Plains
18- SPPC	Southwest Power Pool/Central	Central Great Plains
19- SPPN	Southwest Power Pool/North	Northern Great Plains
20- SRSG	WECC/Southwest	Southwest
21- CANO	WECC/CA North	Northern California
22- CASO	WECC/CA South	Southern California
23- NWPP	WECC/Northwest Power Pool	Northwest
24- RMRG	WECC/Rockies	Rockies
25- BASN	WECC/Basin	Great Basin

FIGURE 6 - ELECTRICITY MARKET MODULE REGION MAP[7]

[6] https://www.eia.gov/outlooks/aeo/
[7] Electricity Market Module region map: http://www.eia.gov/forecasts/aeo/pdf/nerc_map.pdf

3.6 TARIFFS

Tariffs can significantly influence the cost of energy storage systems by affecting the price of imported components such as batteries, inverters, and control systems. Tariffs impact manufacturers differently depending on their geographic location, supply chain structure, manufacturing process, and sourcing strategies. In contrast, manufacturers with vertically integrated operations or domestic supply chains may be less affected, gaining a competitive edge in tariff-heavy markets. Smaller firms or startups often struggle more, as they lack the scale or flexibility to absorb cost fluctuations or renegotiate supplier contracts. Meanwhile, large multinational corporations may mitigate tariff exposure by shifting production across borders or leveraging trade agreements. The baseline analysis represents pricing without tariff volatility using January 2025 tariffs.

3.7 INVESTMENT TAX CREDITS

To be eligible for the ITC, current Internal Revenue Service guidance requires the project to meet Domestic Content thresholds in addition to Prevailing Wages. The accounting of these parameters can be complex and will require tax and accounting skills to manage the process. This report does not offer guidance to IMEA regarding ITC eligibility; however, it applies a 30% rate to the BESS CAPEX portion and also includes a cost sensitivity analysis without ITC.

3.8 COST SNAPSHOT

Establishing a BESS cost reference case provides a foundational benchmark for evaluating project feasibility under a 30% Investment Tax Credit (ITC) scenario. However, this baseline must be interpreted with caution, as numerous variables can significantly influence actual project costs. The reference case presented in this analysis reflects average capital and operational expenses for a standardized system configuration assuming 30% ITC eligibility. Actual costs, however, may vary widely depending on the specific use-case and project installation parameters. Therefore, the reference case (Figure 10) should be viewed as a starting point and continuously refined to reflect project-specific conditions for accurate financial modeling.

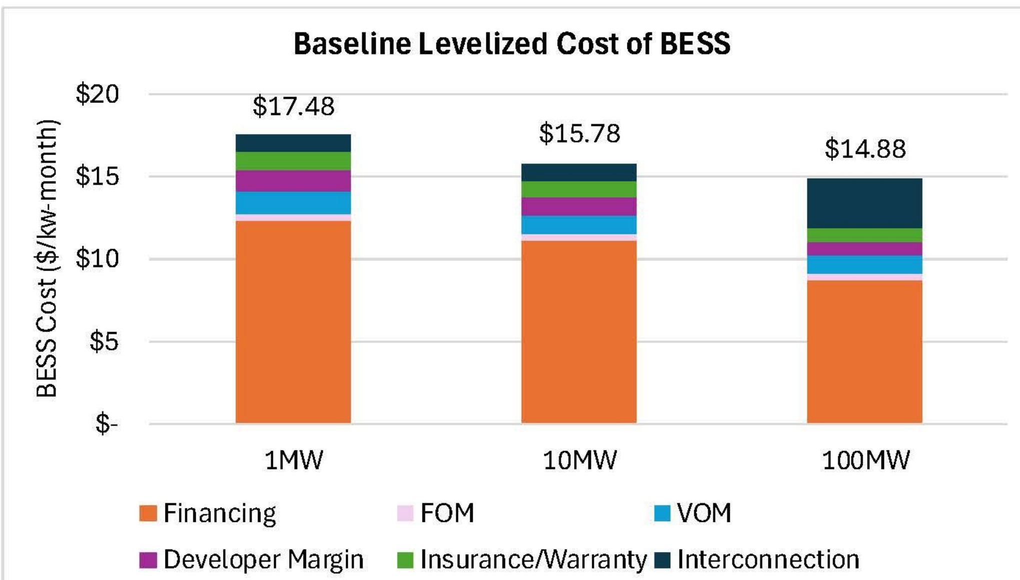


FIGURE 7 – BASELINE ANALYSIS LEVELIZED COST OF ENERGY STORAGE (30% ITC)

4 Benefit Modeling

Modeling BESS value in the market requires an integrated methodology that captures the system's multi-value participation across capacity, transmission, energy arbitrage, and ancillary service value streams. The approach begins with applying BESS performance that defines operational parameters such as power rating, energy capacity, round-trip efficiency, degradation, and state-of-charge limits.

4.1 RESOURCE ADEQUACY

Resource adequacy refers to having sufficient resources—such as generation, storage, or demand response to reliably meet future electricity demand, plus a reserve margin to ensure reliability during peak stress times. Common industry benchmarks include metrics like the Loss of Load Expectation/Probability (LOLE/LOLP), Expected Unserved Energy (EUE), and reserve margin percentages based on reliability targets (e.g., one day in 10 years). Capacity markets act as an "insurance policy" by paying resources today to guarantee readiness in future peak periods, thereby underpinning grid reliability.

4.1.1. Capacity Price Projections

GDS projects RTO regional capacity prices based on market fundamentals and anticipated regulatory changes. For demand fundamentals, GDS considers long-term growth forecasts as well as RTO reserve margin outlooks. For supply fundamentals, GDS reviews publicly available planning information as well as generator interconnection queue data. A forward view of supply / demand balance is compared against historical market results to inform forward capacity price projections. Additionally, GDS considers ongoing and anticipated regulatory changes, considering both rule changes that have been approved but not yet implemented as well as rule changes that are anticipated to be approved in the future. For example, in MISO, GDS includes consideration of MISO's transition to the Direct Loss of Load accreditation methodology beginning in 2028. The base capacity price assumption reflects the currently anticipated demand / supply imbalance, with load growth largely outpacing the addition of new supply for several years before supply catches up and sets new long-term equilibrium.

4.1.2. PJM Capacity

Within the PJM context, the capacity value is defined through PJM's capacity accreditation framework, where energy storage resources contribute to Resource Adequacy based on their Effective Load Carrying Capability (ELCC) and duration-adjusted performance metrics. This accredited capacity determines the storage asset's participation in the Reliability Pricing Model (RPM) capacity market. The resulting capacity revenue is monetized by applying the RPM Base Residual Auction clearing price (or applicable incremental auction price) to the BESS's accredited capacity, forming a key revenue stream in the model. GDS includes consideration of the ongoing review[8] of the Variable Resource Requirement (VRR) and the 2028 Base Residual Action (BRA), with the extension of the price cap. This review indicated that Gross Cost of New Entry (CONE) capacity pricing will be $33.98/kw-month for the 2028/2029 delivery year with net CONE at $21.90/kw-month.

[8] Quadrennial Review Proposal, Market Implementation Committee, July 9th, 2025, page 5. https://www.pjm.com/-/media/DotCom/committees-groups/committees/mic/2025/20250709/20250709-item-06-1---quadrennial-review-proposal---pjm.pdf

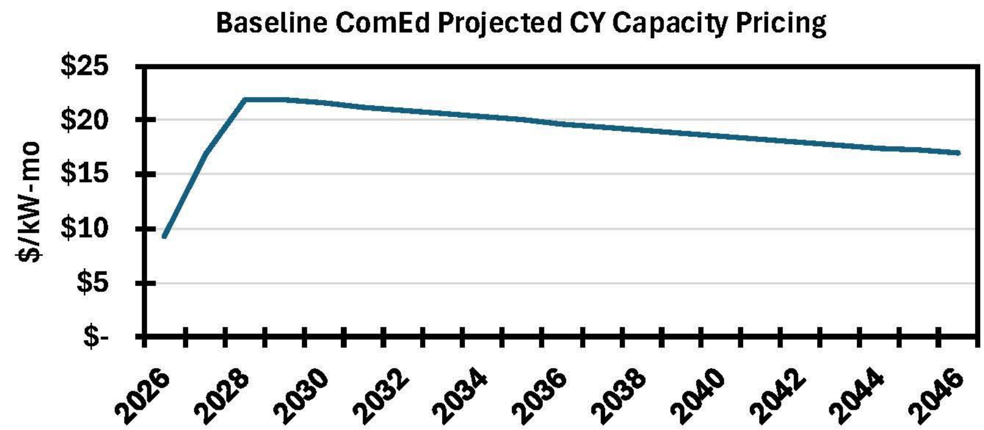


FIGURE 8 – PJM COMED CAPACITY PRICE FORECAST

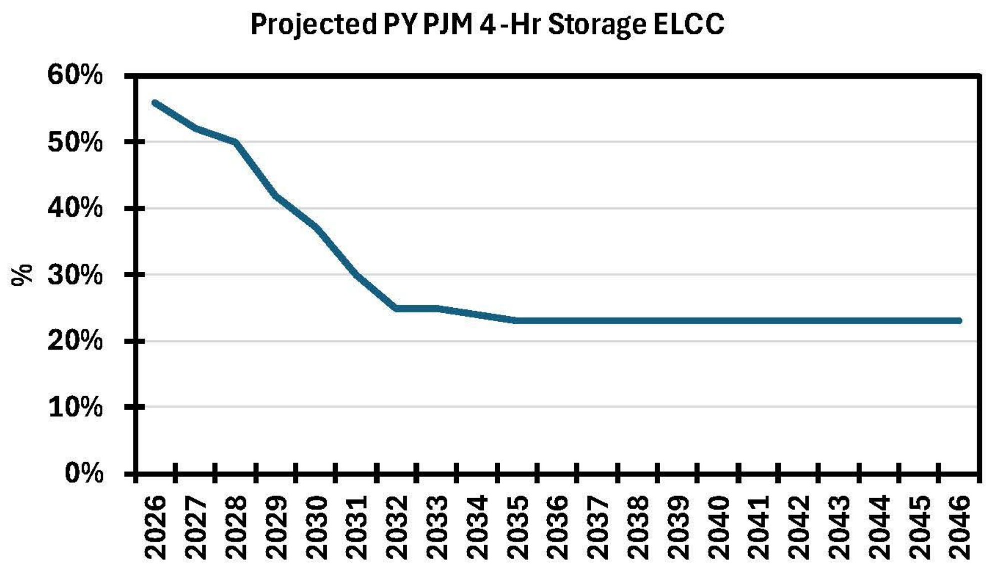


FIGURE 9 - PJM ELCC PROJECTIONS[9]

[9] https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings.pdf

4.1.3. MISO Capacity

Within the MISO context, the capacity value is represented through the accreditation rules, where storage contributes to Planning Resource Adequacy based on its accredited capacity factor and duration-adjusted capacity credit. This capacity contribution is monetized by applying the MISO capacity market clearing price (Cost of New Entry or annual Planning Resource Auction price) to the BESS's accredited capacity, forming one major revenue stream in the model.

MISO's capacity accreditation method is a process to determine the reliable capacity value of each resource for grid planning by accurately measuring its contribution to system reliability during the highest-risk hours. For the 2028/2029 planning year, MISO is transitioning to a new direct loss of load (DLOL)-based methodology, which involves a two-step process of measuring a resource's expected marginal contribution and using a historical resource-level approach during critical hours. This approach varies by resource type (e.g., thermal, renewable, storage) to better reflect their unique characteristics and availability when the grid is stressed.

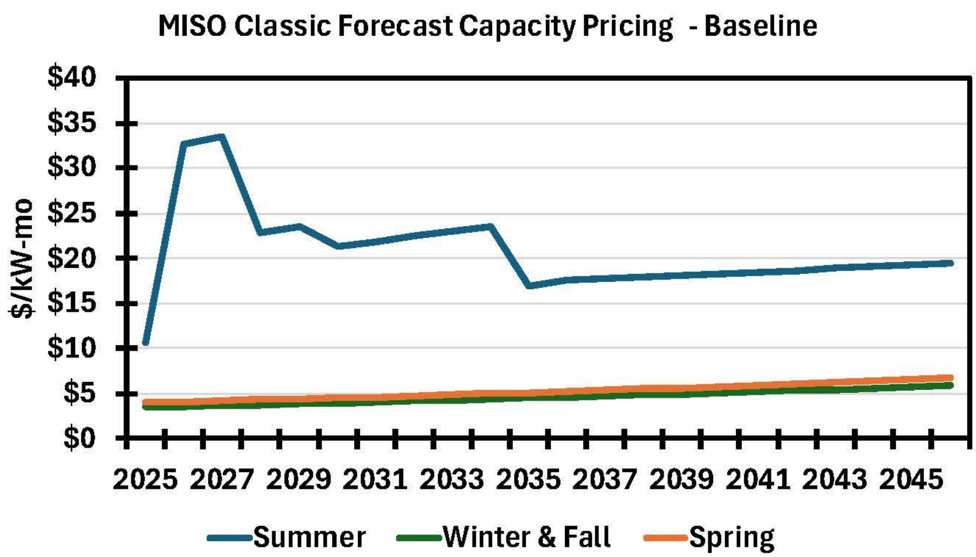


FIGURE 10 - MISO CAPACITY PRICE FORECAST

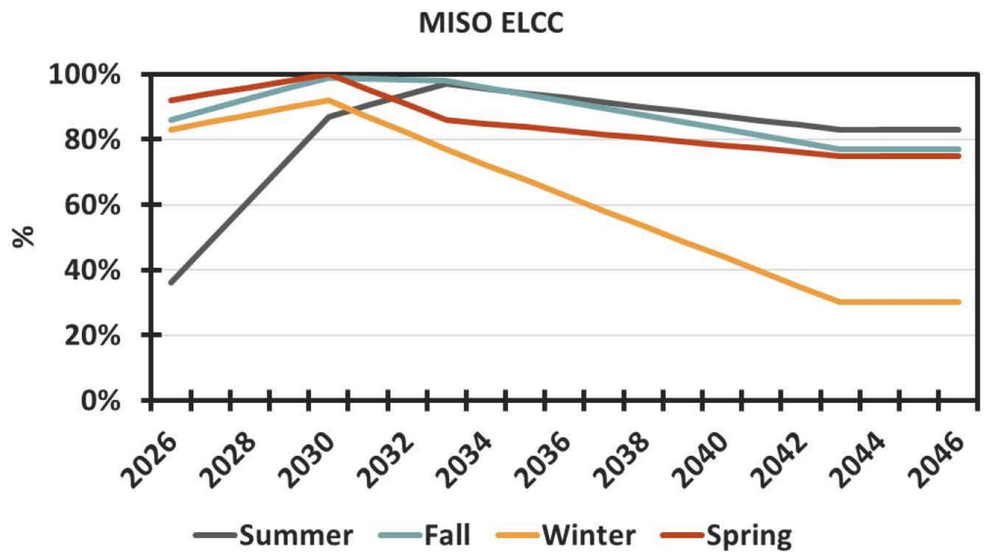


FIGURE 11 - MISO ELCC PROJECTIONS

4.2 ENERGY ARBITRAGE

Modeling incorporates locational and temporal price signals, reflecting congestion management and arbitrage opportunities within the Locational Marginal Pricing (LMP) framework derived from historical data (Figure 12 and Figure 13). The arbitrage value is quantified by simulating BESS charge (at the off-peak 24-hour LMP) and discharge cycles (at the on-peak t 4-hour LMP) against hourly LMPs, thereby estimating gross margin from energy market participation, while including the efficiency losses in the BESS cost during the charging cycle.

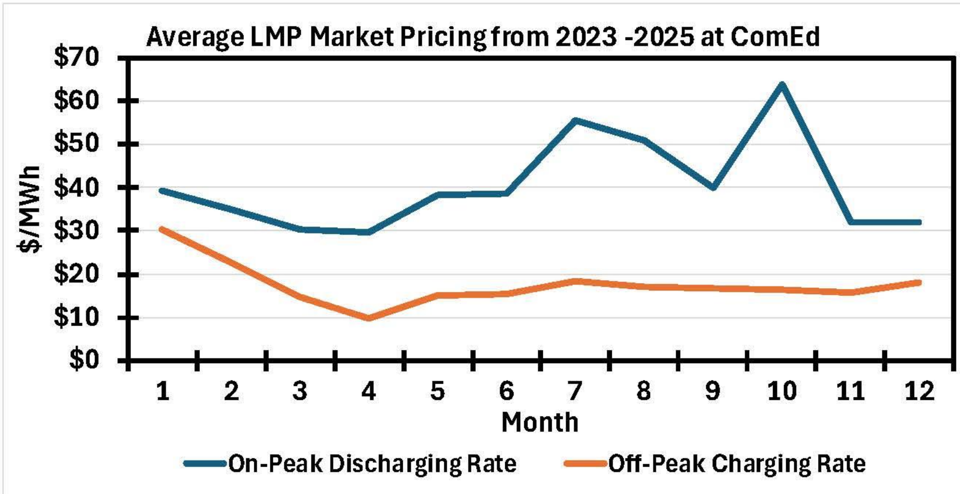


FIGURE 12 - PJM LMP ULTLIZED FOR ARBITRAGE CALCULATIONS

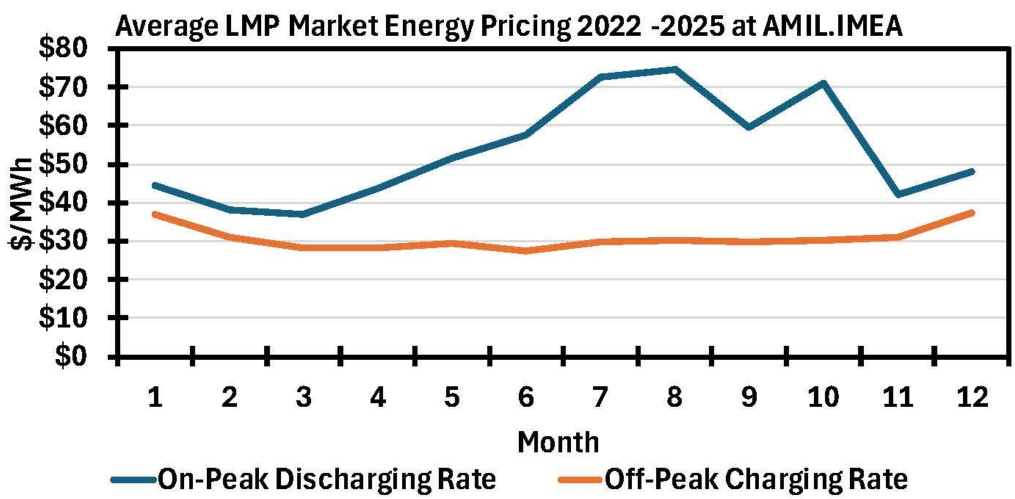


FIGURE 13 - MISO LMP UTLIZED FOR ARBITRAGE CALCULATIONS

4.3 ANCILLARY SERVICES

Ancillary service revenues—such as frequency regulation and spinning reserves—are estimated through a process that allocates capacity between capacity and transmission markets based on observed clearing prices and market participation rules. The resulting total value can be stacked with applied sensitivities to account for uncertainty in market prices and system conditions, providing a comprehensive estimate of the BESS's net market value across all major MISO and PJM value streams.

4.3.1. PJM Ancillary Services

PJM operates several key ancillary service markets essential for grid stability, which are attractive for BESS deployment. These services include Regulation (RegUp and RegDown), Synchronized Reserve (SRS), Non-Synchronized Reserve (NSRS or PRS/TMRS), Black Start (not market-based), and Reactive Power/Voltage Support (cost-of-service). BESS assets in PJM can tap into multiple ancillary service streams, with regulation market being the most valuable due to fast response. Reserve market participation offers incremental gains, while black start and reactive power services represent strategic niches. With proper configuration, controls, and compliance, BESS projects can significantly boost returns by stacking ancillary revenue in PJM's evolving energy landscape. RegD value has ranged dramatically over the market's history, with $0.50-$3.00/kw-mo range observed over recent years. GDS utilizes a flat $1.00/kw-mo rate in the analysis to represent probable value over the next 20-30 years given that this market may continue to become diluted with increased BESS deployments.

4.3.2. MISO Ancillary Services

BESS in MISO can provide ancillary services like frequency regulation, spinning and supplemental reserves, and voltage support, but MISO is currently in the process of developing specific requirements for grid-forming capabilities for BESS to participate in these markets. MISO is the only regional transmission organization (RTO) that has historically restricted inverter-based resources from providing ancillary services. However, MISO is working on new rules and technical requirements for grid-forming (GFM) inverters to enable BESS to participate more fully. Due to this market still being in development with an unidentified value proposition, MISO ancillary service value is being excluded from this study.

4.4 TRANSMISSION BENEFITS

Transmission service charges are primarily related to Network Integration Transmission Service (NITS), along with other cost recover transmission charges, as a demand-based tariff used by Regional Transmission Organizations (MISO and PJM) to recover annual transmission investment, maintenance, operational costs from network customers. As such, reducing IMEA member's peak load during system peak hours is a primary lever to lower NITS obligations. NITS charges are not based on total energy consumption, but instead on peak demand during limited interval(s), making them particularly susceptible to spikes. BESS offers a powerful mechanism to target and reduce NITS costs. By predicting when to discharge during system peaks, BESS can lower coincident peak demand and thus annual transmission charges. When paired with accurate peak forecasting, automated controls, and proper sizing, BESS can provide a strategic, performance advantage. For purposes of this study, it is assumed that a 4-hour BESS can be 80% effective if the appropriate peak prediction algorithm is utilized during dispatch.

4.4.1. PJM Transmission Charges

NITS is a demand-based transmission charge based on a facility's CP demand during the highest-demand hour(s) in the zone or PJM region. NITS charges are calculated using Annual Transmission Revenue Requirements (ATRR) and a zonal Coincident Peak (CP) in relation to system-wide peak demand. The ComEd zone was utilized in this study to assess NITS, NITS is a component of the transmission costs for wholesale electricity customers. NITS covers the cost of using the high-voltage grid to deliver power.

4.4.2. MISO Transmission Charges

Energy Storage Resources (ESR) that use the MISO transmission system for charging are required to obtain Transmission Service (TS), similar to the requirements for load. In MISO, an ESR may use any type of TS to meet this requirement. The two notable types of TS available are NITS and Point to Point (P2P). Additionally, P2P service may be obtained on a long versus short-term and firm versus non-firm basis.

NITS is typically used by LSEs because it allows the LSE to use a fleet of resources to serve its load. With NITS, the charges are primarily based on the transmission customers' load (the LSE's demand in this example) at the time of zonal peak. Since the charges are based on the LSE's load, not its overall resource usage, an LSE has flexibility to acquire more generating capacity than its peak demand and to use its generating resources in an economically efficient manner without impacting on its TS cost. For an ESR, the resource flexibility provided by NITS would not be beneficial, but it does allow for the potential to minimize TS costs by limiting the amount of charging that occurs during high load hours that could contain the monthly zonal peak.

MISO charges transmission customers based on the transmission zone in which the customer is located. Although the prior section describes the primary rate for each TS type, there are a variety of TS charges that a transmission customer can be liable for, and the rates charged are different for each MISO transmission zone. Additionally, some charges are zone-specific, so only customers in that zone are charged. The estimated charges in this report are based on a ESR located in the Ameren Transmission Company of Illinois – MISO Zone 3A using Schedule 9 NITS 2026 charges[10] to project a forecast (currently $8.95/kw-month).

4.5 BASELINE BENEFITS SUMMARY

The baseline benefits are expressed below in terms of the Net Present Value (NPV) of the benefit cashflows over the course of the expected 20-year useful life of the BESS asset[11]. These numbers are subsequently compared with the BESS cost over the life of the asset, as described in the cost analysis section of this report, to calculate the net benefits.

$000	Arbitrage	Transmission	Capacity	Total
1MW/4-HR	$288	$1,549	$1,823	$3,660
10MW/4-HR	$2,879	$0	$18,230	$21,109
100MW/4-HR	$28,788	$0	$182,299	$211,087

FIGURE 14 - BASELINE NPV OF MISO ZONE 3A BENEFITS ($000)

$000	Arbitrage	Transmission	Capacity	Ancillary	Total
1MW/4-HR	$323	$425	$1,655	$240	$2,643
10MW/4-HR	$3,232	$4,248	$16,546	$2,400	$26,426
100MW/4-HR	$32,322	$0	$165,463	$24,000	$221,785

FIGURE 15 - BASELINE NPV OF PJM COMED BENEFITS ($000)

[10] https://www.misoenergy.org/markets-and-operations/settlements/ts-pricing/#nt=%2Ftspricingtype%3AZonal%20Rates&t=10&p=0&s=Updated&sd=desc

[11] Discount rate utilized in formula is 0%.

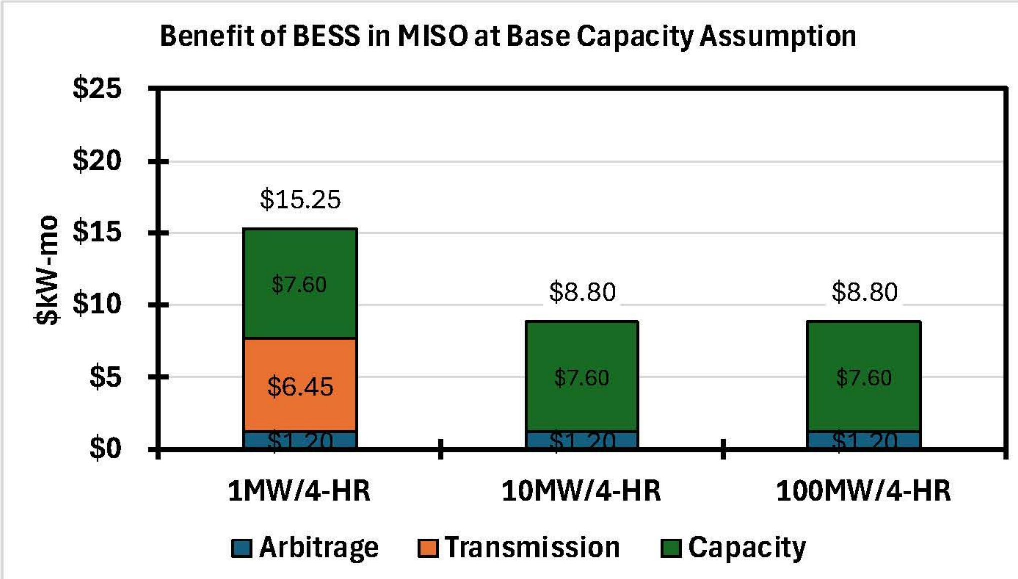


FIGURE 16 - BASELINE LEVELIZED MISO ZONE 3A BENEFITS ($/KW-MONTH)

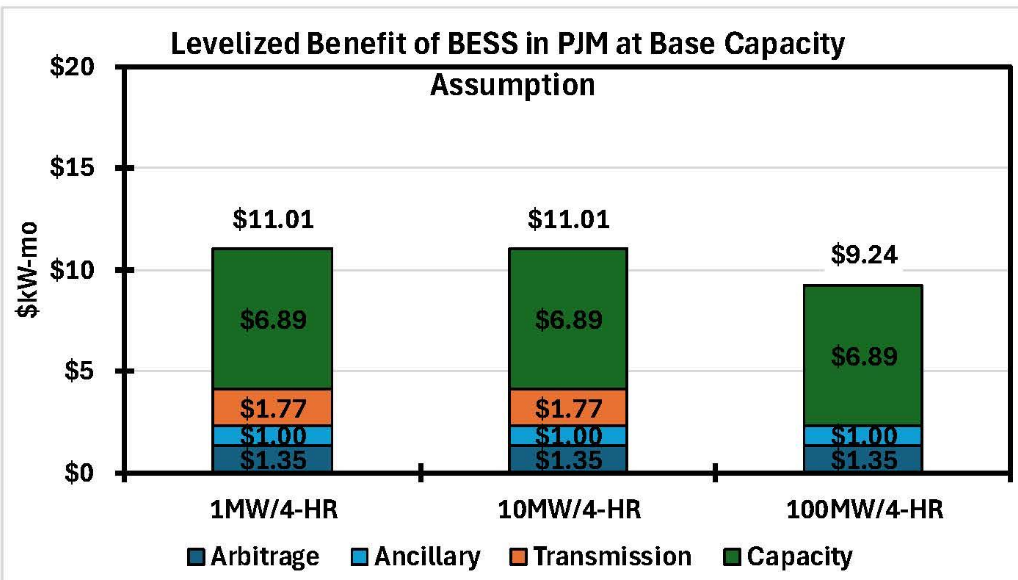


FIGURE 17 - BASELINE LEVELIZED PJM COMED BENEFITS ($/KW-MONTH)

5 Cost Benefit Summary

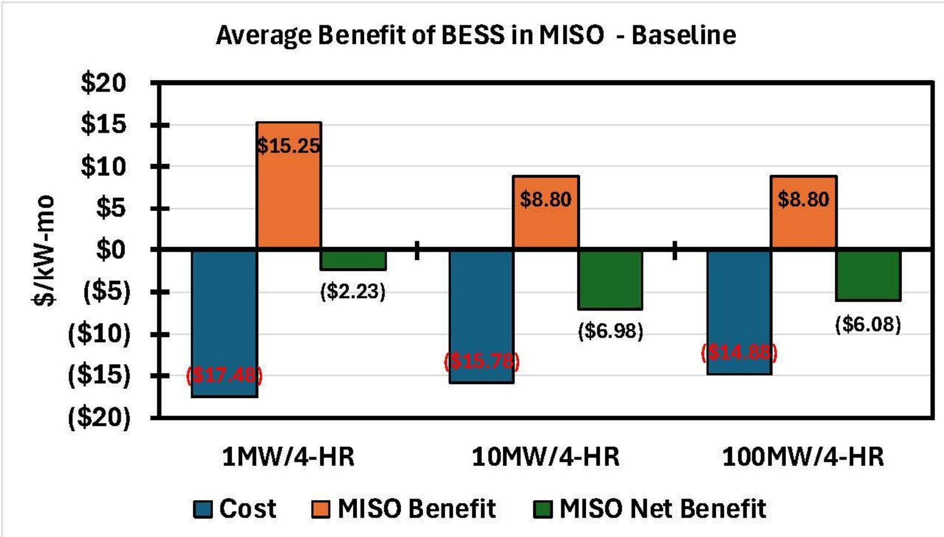


FIGURE 18 - LEVELIZED NET BENEFIT IN MISO ZONE 3A

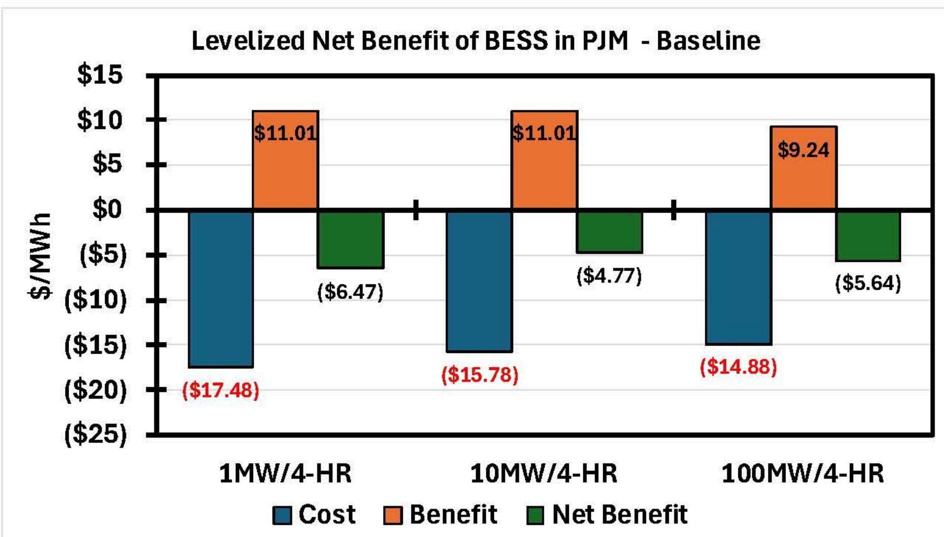
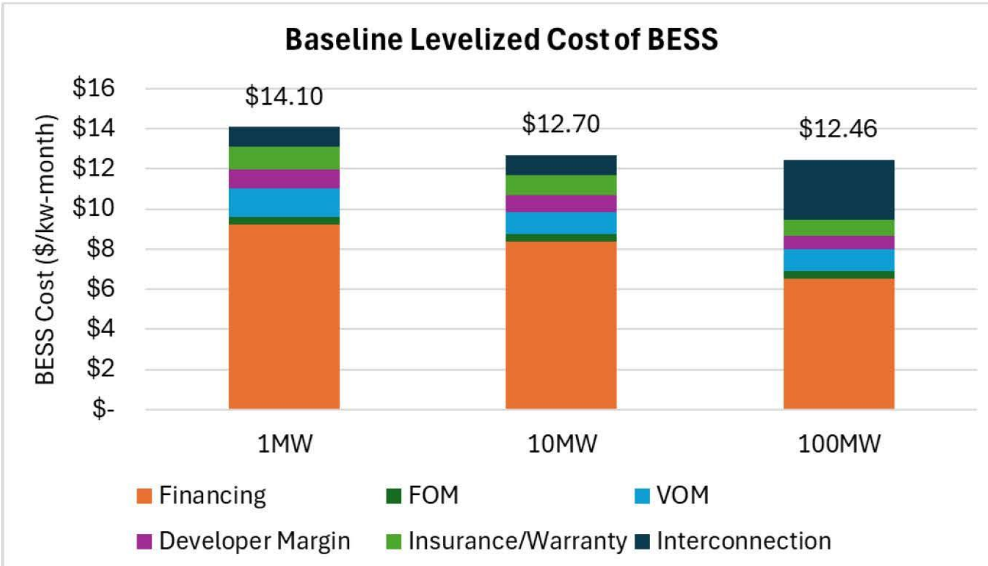


FIGURE 19 – BASELINE COST-BENEFIT OF BESS IN PJM COMED

*Baseline assumptions: 20% Tariff on < 55% of the equipment CAPEX, 0% discount rate, 10% developer margin on CAPEX/FOM over term, Chicago metro regional cost factor, moderate capacity and transmission benefit scenarios, arbitrage value based upon relevant LMPs, $1.00/kw-mo PJM Ancillary service value, developer financing rate of 8.5%, 2% inflation rate on O&M, 95% availability guaranty, 20-year energy capacity warranty.

Appendix A – Municipality Owned Cost-Benefit Sensitivity



***Baseline assumptions utilized except cost of debt (4.8%) applicable to CAPEX financing**