New Jersey Energy Storage Analysis (ESA)

Final Report

Responses to the ESA Elements of the Clean Energy Act of 2018

The State University of New Jersey

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TABLE OF CONTENTS

FIGURES

TABLES

EXECUTIVE SUMMARY

Energy storage (ES) is an essential component of New Jersey's sustainable energy future because it enables the grid to handle increasing amounts of clean renewable energy and manage changing, highly variable electricity demand. This report answers a set of questions posed by the New Jersey State Legislature regarding the status of ES technologies, the purposes they can cost-effectively serve within New Jersey, and how to encourage their wider implementation and cost reduction with time. Other recent studies have confirmed that ES adds value to the bulk power system; hence, this report devotes effort to topics that have received relatively less attention: technology characteristics and cost trajectories, and the fit with specific applications at the distribution level and on the customer-side of the meter. This report is an arms-length technical analysis rather than a policy analysis so state policymakers can use this work to inform the development of policy recommendations.

At a high level, this report finds that two familiar technologies (pumped hydro and thermal storage) are currently cost-effective and do not face financial barriers to increased deployment. The cost of Lithium-Ion (Li-ion) battery storage (least costly of the present battery technologies) is dropping rapidly but it is not currently cost-competitive for most applications. It is currently cost-effective in providing ancillary services for the bulk power market. Battery storage applications with attractive net social benefits that do not yet yield positive returns for investors include increasing hosting capacity for decentralized solar photovoltaics (PV) on certain distribution systems; and increasing resilience in combination with solar PV on the customer side of the meter for high-reliability users such as hospitals, hotels, and supermarkets. Incentives to encourage prompt deployment of 600 MW of battery storage for these applications likely need to be on the order of $140-$650 million. Deploying systems more slowly will cost less. Medium-term applications that are likely to help New Jersey realize a sustainable energy future include grid stabilization for offshore wind projects and electric vehicle charging stations.

Background

Electric utilities have used ES technologies such as pumped hydro for many decades, and buildings have long used thermal energy storage as part of water heating, space heating, and cooling systems. Motor vehicles and portable electronic devices have long used batteries, but recent dramatic cost reductions are now bringing batteries to new electric power applications. Various battery chemistries are now entering use, with more on the way. These ES devices work better in some applications than others, and an understanding of the technical characteristics and the applications is key to making good energy policy that promotes appropriate ES investments.

The New Jersey Clean Energy Act (P.L. 2018, CHAPTER 17, herein, "Clean Energy Act" or "CEA"), adopted on May 23, 2018, directs the New Jersey Board of Public Utilities (NJ BPU) to answer nine questions about ES in a report due on May 23, 2019. The NJ BPU contracted with Rutgers University on November 1, 2018 to conduct an analysis of ES in New Jersey to help staff answer these questions by the May 23, 2019 deadline. The scope of work included ES technology evaluation, ES analytics and network-level evaluation, and ES economic assessment. The work was performed by faculty, staff, and students from the School of

Engineering and the E.J. Bloustein School of Planning and Public Policy. Rutgers also hosted an ES stakeholder meeting to provide consultation opportunities with knowledgeable parties and enhance the value of the analysis. Consideration of regulatory policy was not part of the project scope, but given the intersection between the Rutgers team's technical work and emerging state and federal regulatory issues, the analysis does cover some important regulatory topics. The full report provides answers to the legislature's nine questions (see section on CEA Elements). This executive summary shares key findings and suggested next steps.

Bulk Power System Findings

PJM Interconnection has active markets for ancillary services, and ES devices already participate in those markets, especially to provide frequency regulation services. PJM-wide, behind-the-meter batteries have increased their provision of frequency regulation services from 20,000 MWh in 2014 to 72,000 MWh in 2018, with this trend continuing in 2019. This ES application remains healthy in part because the Federal Energy Regulatory Commission regularly revisits the rules under which PJM operates this market, most recently on January 19, 2019.

Energy storage can facilitate, and in some cases enable, the introduction of large-scale offshore wind resources or large-scale solar farms by firming the resource at or before the points of interconnection with the transmission network, time shifting to when electricity is needed, and possibly deferring new transmission investments. A high-level analysis of two case studies based on New Jersey's planned offshore wind solicitations of 1100 MW and 2400 MW confirms that there are benefits at the bulk power level associated with deployment of ES.

Energy storage can also hedge against risks of large variations in Locational Marginal Prices (LMP) at the bulk level. A preliminary analysis of historical LMPs across New Jersey identifies potential points of market entry for ES at the bulk level. Further analysis of this topic will require more accurate interconnectivity and load data.

Distribution–Level Findings

Enhancing hosting capacity on existing distribution networks by installing ES could allow the increased deployment of solar photovoltaics (PV) and electric vehicles (EV) in New Jersey. Coupling ES with PV and/or EVs can allow deferral of distribution system upgrades that might otherwise be required. This report covers several case studies examining the value impact of ES of various sizes on PV investments across distribution networks.

The key finding for these use cases is that ES adds more value when ES is distributed across the network (rather than centralized at the grid interconnection point) and integrated with PV. However, mobile storage can support distribution networks while repairs are being performed on transformers and other equipment.

Stacking applications, including support for distributed renewable generation and peak power reduction, may also benefit distribution networks. In the absence of renewables, ES can be used to shift load, provide ancillary services if allowed, and possibly enhance resilience. If coupled with renewables, ES can also serve part of the peak demand. Both cases can lead to deferrals in power grid upgrades. In addition, ES can help to improve distribution network stability.

As EV adoption increases, additional opportunities for ES to add value will emerge. One such opportunity includes demand charge reduction for direct current (DC) fast-charge stations, which can enable EVs to participate in interstate travel and may decrease overall range anxiety for EV drivers across the state. A step change in wide-spread ES distribution could be accomplished by further development of Vehicle-to-Grid (V2G) and Vehicle-to-Home (V2H) applications with the result of increased residential resilience and grid stability. Fleet applications of ES might include electric bus fleets, which have been adopted in nearby states as well as other countries.

Customer-side Deployment Findings

Energy storage can improve resilience in public and private facilities by allowing continued operation during outages. A facility's critical or vital load and load factor are important features to consider for ES capacity and duration. Energy storage projects with energy duration of four hours and capacity of 50% or more of the facility peak load generate resilience benefits for many of the use cases, but the associated costs may render these economically unfavorable. ES with small capacity (~25% of peak load) and discharge durations of four hours (covering up to four hours of outages) can generate value by serving up to 50% of critical loads on average at a lower cost. For longer durations, ES alone has less value, and integration with facility level PV or other distributed generation would be favorable.

Pairing ES with both existing and new PV can also unlock federal investment tax credits for ES. The economic viability of these use cases depends on the owner's tax status, cost of technology, the value of load loss, and frequency of outages, among others.

Along with critical facilities such as hospitals, wastewater treatment plants, and senior housing, where the value of avoiding outages is high, there is another resiliency sweet spot that warrants community attention. This is the application of coupled ES, distributed generation, and renewable PV to community emergency shelters such as community centers or school gymnasiums.

Applications of ES for managing demand charges and participating in dynamic demand-response programs are technically feasible, but the economic viability is sensitive to optimal battery sizing details. For some use cases we find that lower-capacity, short-duration batteries at the facility level (e.g., 250 kW where peak load is normalized to 1 MW) produce much more favorable economic outcomes than full 1 MW batteries. Time-of-use (TOU) rates or utility-controlled ES make these customer-side investments more financially attractive.

Economic benefits of ES at the facility level can become more favorable by stacking resilience, peak power reduction, and renewable generation recovery applications. Additionally, peak loads at commercial and industrial facilities around the state are changing due to EV charging and an increase in the electrification of manufacturing and the built environment. As such, ES can in certain cases yield facility owner savings on demand charges and reduced system demand for ratepayers as a whole.

Electric Energy Storage Technologies

The research team assessed a wide portfolio of electric energy storage technologies that are commercially available and near commercially available, to determine their suitability for grid applications in New Jersey. Various types of electric energy storage appropriate for utility-connected applications were evaluated, including mechanical, thermal, electrochemical, and chemical technologies. Besides the ubiquitous pumped hydro storage, other ES solutions exist today that have been successfully implemented on scales in excess of 100 MW and 100 MWh per installation, nationally and internationally, to address the spectrum of utility needs including frequency regulation, peak shifting, renewable integration, and resilience.

Pumped hydro storage (PHS) is a mature and commercial technology, which accounted for over 90% of ES capacity installed in the United States in 2017 at 22.6 GW. Pumped hydro storage still has the lowest lifetime cost of installation, a benefit of utilizing natural geographic conditions. PHS represents the majority of New Jersey's present ES capacity with 420 MW at Yards Creek. Opportunities to implement new installations are restricted by the unique geographical requirements.

Thermal storage is another mature technology which effectively results in a peak shifting of energy usage. At least 9.5 MW of thermal storage has been installed in New Jersey in the form of ice energy storage. Costs are currently lower than Li-ion storage. Broader impacts in service of utility needs, such as frequency regulation and resiliency, are not readily feasible with thermal storage. However, lower costs and risks may make this an attractive approach for adoption within cities and communities with expanding commercial entities.

Li-ion technology, with a downward trend in battery cost, is the fastest growing technology being implemented today. This technology is viewed favorably due to its ability to address a number of utility applications from fast-response frequency regulation to longer-duration peak shift and resiliency. A general trend has been developing towards the 4-hour power delivery for reasons described in detail within this report. Most of the total 44.5 MW of Li-ion systems installed in New Jersey remain short-duration (less than one hour), allowing participation in ancillary services markets or as an emergency back-up, with or without a renewable power source.

Commercial high-temperature sodium sulfur battery technology represents the largest integration of electrochemical energy storage, rated at 108 MW and 648 MWh. This technology offers future cost reduction opportunities due to the intrinsically very low cost of the chemicals utilized. Sodium sulfur is especially attractive for long durations and continuous-use applications.

Emerging flow battery technologies are very attractive for large installations due to their intrinsically cost-effective ability to be scaled into large tanks and subsequent power system versatility by effectively decoupling power from energy. China has moved quickly on flow batteries as its 2017 ES policy requires the deployment of multiple 100 MW-scale vanadium flow batteries. Also, a 200 MW/800 MWh system is currently under construction in Dalian, China, to be commissioned in 2019. Energy storage in the form of hydrogen fed into the utility through fuel cells offers a very low materials cost with very low environmental impact. However, one must consider the cost of poor conversion efficiencies of energy into hydrogen either by direct electrolysis or renewables relative to pure electrochemical systems offering direct electron storage.

Energy Storage Adoption Roadmap for New Jersey

The total ES presently in New Jersey amounts to approximately 477 MW, including a 0.5MW lead-acid asymmetric hybrid system. 420 MW of that total is pumped hydro from a 54 year old facility. However, there are many ES opportunities in New Jersey. For additional ES, PHS would provide the lowest lifetime cost and massive scalability (>GW), but it will require an adequate geographical site, high capital cost, and long construction time. Despite the site restrictions, NJ is very well situated to take advantage of PHS especially in the northern sections of the state where geo-topography and abandoned mines offer much documented opportunity. Some of these geographical features may be advantageous to compressed air energy storage also. Li-ion battery technology is the current mainstream technology, but sodium sulfur and flow batteries have many benefits specifically for longer durations. As opposed to pumped hydro storage, most batteries discussed herein are flexible, modular, and standalone containers that facilitate deployment and trending towards mobility (especially for Li-ion). In addition, installation can be operational within a few months. As such, there are many opportunities for battery deployments in New Jersey. Thermal storage offers cost-effective peak shifting of energy and could be an excellent avenue to reduce daytime stresses on the grid in expanding cities, but do not offer added benefits of resiliency and addressing other utility markets.

Environmental Impacts

Societal benefits of ES due to avoided greenhouse gas, SO_2, and NO_x emissions are small in simple short-term load-shifting applications because peak vs. off-peak marginal emissions rate differences are small and there is a ~15% efficiency penalty associated with the charge-discharge cycle.

Even with the deployment of several thousand MW of offshore wind, the difference between peak and off-peak marginal emissions seems unlikely to change very much before 2030, because natural gas is the marginal fuel during most hours and seasons over the next decade in the very large PJM regional power market.

There may be opportunities to purposefully deploy ES to change the operating order of generators serving the power system following an environmental dispatch strategy. Experience from other states in meeting Regional Greenhouse Gas Initiative (RGGI) obligations could apply in New Jersey. A related idea of potential interest is the “Clean Peak” initiative of New York State which seeks to target high-emitting peaking generators for early retirement by substituting precisely targeted ES investments.

Also, a large environmental benefit is likely to attach to the contribution ES can make to support renewables and EV integration as discussed under distribution-level and customer-side impacts.

Next Steps for Policymakers

The Clean Energy Act directs the Board of Public Utilities to "recommend ways to increase opportunities for energy storage and distributed energy resources in the State, including any recommendations for financial incentives to aid in the development and implementation of these technologies." It will be helpful if this next phase of reporting can address limitations identified in this report; continue data gathering, economic evaluation, benchmarking, stakeholder engagement and policy development; propose pilot projects; develop ES related codes, standards and safety protocols; and develop an implementation plan. There are several policy questions that the current technical analysis cannot directly answer. The following are high priority topics based on stakeholder input, the research team's experience, and the lessons learned in other states.

Value stacking can improve the value proposition for ES applications, to the extent that they avoid technological tradeoffs. What rules are necessary to ensure that customer-side applications can be stacked with distribution-level and bulk power-level applications, without inappropriate double-dipping or sub-optimization? This is likely to be an area where learning by doing is necessary to craft and then refine policies.

Battery costs are dropping rapidly, but many future cost reductions will need to come from reducing soft costs such as permitting, customer acquisition, and financial risk. Which market rules and incentive arrangements have lower soft costs? Which ones encourage market learning, experience acquisition, and achievement of scale economies?

A related issue is that there is little publicly available data about key technical aspects of ES and about specific deployment opportunities, such as hosting capacity on distribution systems. How can policies encourage collection and public sharing of regular data on ES installations and their performance, and on market opportunities that may emerge on transmission and distribution networks?

Should utility ownership of ES devices be limited to ensure creation of a robust market, or do the benefits of vertical integration outweigh this concern? The PJM frequency regulation market and its oversight processes may offer practical insights for other ES applications.

Finally, as New Jersey pursues its targets of 600 MW of ES by 2021 and 2,000 MW by 2030, policymakers should set priorities for what these deployments should accomplish. Is the goal:

- To achieve the targets with the least expenditure of public funds?
- To accelerate local learning about the technology?
- To experiment with different technologies to better understand their relative strengths?

- To accelerate adoption of EVs that could benefit from ES-enabled infrastructure improvements?
- To accelerate the installation of more PV in our region?

The research team suggests that it would be valuable to establish pilot programs and pursue a balanced portfolio to ensure that New Jersey gains experience with the bulk power system, distribution-level, and customer-side applications, and multiple technologies. Within each category, there are project opportunities that are at or close to cost-effectiveness, especially when coupling ES and renewables, and ES and EV infrastructure such as V2G/V2H. Given New Jersey's coastal vulnerabilities and its car-dependent economy, it makes sense to prioritize resiliency and EV applications.

The full report provides a more thorough discussion of the findings summarized here, including contextual data, explanations of methods, results of calculations, and interpretations of the implications for New Jersey.

LIST OF ABBREVIATIONS

AC	alternating current
ACE	Atlantic City Electric
BCR	benefit-cost ratio
BEST	Battery Energy Test Facility
BICO	breakdown installed costs of storage
CAES	compressed air energy storage
CapEx	capital expenditures
C&I	commercial and industrial
CBA	cost-benefit-analysis
CEA	Clean Energy Act
CEA	Clean Energy Group
Cd	cadmium
CO_2	carbon dioxide
DC	direct current
DCFC	direct current fast charging
DER	distributed energy resources
DG	diesel generation
DOD	depth of discharge
DOE	U.S. Department of Energy
DR	demand response
DRIPE	demand reduction induced price effects
EIA	Energy Information Agency
EBM	electricity bill management
EDC	electric distribution company
EDLC	electrochemical double layer capacitors
EMC	Electric Membership Cooperative
EMP	Energy Master Plan
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ES	energy storage
ESA	energy storage analysis
ESCT	Energy Storage Computational Tool
EV	electric vehicle
FERC	Federal Energy Regulatory Commission
FES	flywheel energy storage
FR	frequency regulation
GHG	greenhouse gas
GW	gigawatts
GVEA	Golden Valley Electric Association
HEPCO	Hokkaido Electric Power Co., Inc.
hr	hour
ILZRO	Lead Zinc Research Organization

IRENA	International Renewable Energy Agency
ISO	independent system operator
ITC	investment tax credit
JCP&L	Jersey Central Power & Light
JRC	Joint Research Centre
kW	kilowatt
kWh	kilowatt hour
LBNL	Lawrence Berkeley National Laboratory
Li-ion	lithium-ion
LMP	locational marginal prices
MW	megawatt
MWh	megawatt hour
Na	sodium
NaS	sodium sulfur
$NaAlCl_4$	sodium ion conductive salt
NG	natural gas
Ni	nickel
NiCd	nickel cadmium
NiMH	nickel metal hydride
NJ BPU	New Jersey Board of Public Utilities
NJR	New Jersey Resources
NOx	nitrogen oxides
NPV	net present value
NREL	National Renewable Energy Laboratory
NRC	National Resource Council
NYSDPS	New York State Department of Public Services
NYSERDA	New York State Energy and Development Authority
O&M	operations and maintenance
OSW	offshore wind
Pb-acid	lead-acid
PbO_2	lead dioxide
PCS	power conversion system
PHS	pumped hydroelectric storage
PJM	PJM Interconnection, LLC
PREPA	Puerto Rico Electric Power Authority
PSE&G	Public Service Electric and Gas Company
PV	photovoltaic
R&D	research and development
RECO	Rockland Electric Utility Company
Redox	reduction and oxidation
SCE	Southern California Edison
SEI	Sumitomo Electric Industries, Ltd.
SP	stakeholder process
TMS	thermal management system
T&D	transmission and distribution
TEPCO	Tokyo Electric Power Company

TOU	time of use
UPS	uninterruptible power supply
VLA	vented lead-acid
VRLA	valve-regulated lead-acid
VOLL	value of lost load
V2G	vehicle-to-grid
V2H	vehicle-to-home
ZEBRA	zero emission battery research activity

OVERVIEW

The New Jersey Board of Public Utilities (NJ BPU) retained Rutgers University to conduct an analysis of energy storage (ES) in New Jersey pursuant to the New Jersey Clean Energy Act (P.L. 2018, CHAPTER 17, herein, "Clean Energy Act" or "CEA") adopted on May 23, 2018.

For the purpose of clarity this report will use the definition of ES adopted by MSSEIA: *"An energy storage system is a system capable of storing energy from the electric grid and delivering the stored energy back to the grid at a later time, or avoid the usage of power from the grid at a later time, to serve a policy objective."*

The contract period ran from November 1, 2018, to May 23, 2019. The scope of work included ES technology evaluation, ES analytics and network-level evaluation, and ES economic assessment. During this time, the scope of work expanded to include an ES stakeholder meeting hosted by Rutgers University to provide input to inform and enhance the value of the analysis. The impact of regulatory issues was not part of the scope of work for this Energy Storage Analysis (ESA), however, given the intersection between the Rutgers Team's technical and economic analysis with State and Federal regulatory issues, this final report does cover some important regulatory topics.

This ESA report supports the State's goal of establishing a clean energy economy that addresses climate change, other environmental challenges, economic development, reliability and resiliency. The analysis, findings, and recommendations are all considered in the context of enhancing the State's ability to achieve its clean energy environmental and economic objectives. The report documents the costs and benefits of ES including renewable integration and associated reductions in air emissions, peak-load shaving and demand charge reduction, reliability and resiliency enhancement, and other benefits.

The purpose of this ESA report is to communicate the Rutgers team's findings regarding the net benefits of ES, address the challenges and issues and provide recommendations regarding structuring program incentives. The report identifies and quantifies the benefits and costs of ES systems to the State of New Jersey. These benefits have multiple objectives that target ratepayers, renewable energy support, electric vehicle (EV) adoption, and grid reliability/resiliency.

The CEA at *(N.J.S.A.* 48:3-87.8 (1) (a)) requires that:

"In conducting this analysis, the board shall:

(1) consider how implementation of renewable electric energy storage systems may benefit ratepayers by providing emergency back-up power for essential services, offsetting peak loads, and stabilizing the electric distribution system;

(2) consider whether implementation of renewable electric energy storage systems would promote the use of electric vehicles in the State, and the potential impact on renewable energy production in the State;

(3) study the types of energy storage technologies currently being implemented in the State and elsewhere;

(4) consider the benefits and costs to ratepayers, local governments, and electric public utilities associated with the development and implementation of additional energy storage technologies;

(5) determine the optimal amount of energy storage to be added in the State over the next five years in order to provide the maximum benefit to ratepayers;

(6) determine the optimum points of entry into the electric distribution system for distributed energy resources; and

(7) calculate the cost to the State's ratepayers of adding the optimal amount of energy storage.

The board shall also consider the need for integration of distributed energy resources (DER) into the electric distribution system and how to incorporate DER into the electric distribution system in the most efficient and cost-effective manner."

Collectively, these seven items and the subsequent paragraph, set forth above, are referred to in this ESA report as the "Clean Energy Act (CEA) elements." We have divided the final paragraph into two additional elements and numbered them (8) and (9):

(8) Determine the need for incorporating DER into the electric distribution system.

(9) Determine how DER may be incorporated into the electric distribution system in the most efficient and cost-effective manner.

The remainder of this section covers highlights of ES benefits supported by our analysis, the challenges encountered in our analysis, and policy recommendations to structure an incentive program. The subsequent sections cover a discussion of each of the above listed nine CEA elements.

Highlights of Energy Storage Benefits

Our key findings suggest the following potential benefits for New Jersey:

1) Generally speaking, ES can improve resilience in public and private facilities. Facility's critical or vital load and load factor are important features to consider for storage capacity and duration. To serve typical critical loads (70% or higher for many facilities) and for durations of around four hours, the economic benefits of standalone energy can only be justified if value of load loss (VOLL) is significantly high and there are incentives available. Also, the frequency of power outages (more frequent due to natural events), location of facility (e.g., close to shorelines) and priority assigned to the facility can influence the economic benefits of ES.

2) When coupled with PV or other renewable resources, the resiliency benefits of ES can be significantly enhanced.

3) Economic benefits of ES at the facility level can turn more favorable with stacking up resilience and peak power reduction. With projected increase in peak load at commercial and industrial facilities around the State (e.g., due to EV charging and more electrification of manufacturing and built environment) the value of peak load reduction will be significant for facility owners and for the ratepayers as a whole. The CO_2 impact attributed to ES installation will depend on how much of ES is charged from renewable sources vs. the grid.

4) Stacking resilience and peak power reduction can also benefit distribution networks as demonstrated by a number of case studies in this report. In the absence of renewables, ES is only used to shift load, and in their presence, the renewable and clean power can serve part or all of the peak demand. Both cases can lead to deferrals in power grid upgrades especially with emerging trends in electrification of transportation, manufacturing and other built environments.

5) Hosting capacity is one application by which ES can generate benefits for New Jersey. In our analysis of sample networks, we observe increases of up to 100% in photovoltaic (PV) installations when combined with suitably sized ES. This can translate to significant savings or deferral of power grid upgrades while enabling faster PV installation growth.

6) At the bulk level, ES can support renewable energy generation. To recover renewable power from such installations, transmission level upgrades can be deferred by adding ES. Our high-level analysis of a case study based on New Jersey's planned offshore wind (OSW) of 1100 MW quantifies the amount of renewable power recovery with ES installment without major upgrades to transmission lines.

7) At the bulk level, ES can also be used for ancillary services, such as frequency regulation (FR). Many sources discount the longer-term stability of the FR market, which is thought to already be oversupplied. However, a recent New Jersey battery installation by Viridity seems to show confidence in stable earnings from FR services.

Highlights of Technical Challenges and Next-Phase Recommendations

The State may want to consider establishing pilot programs for various types of ES applications. A pilot program would allow the State to obtain better information regarding the costs, benefits, and performance of different storage technologies than currently available. Having this additional and more accurate information would enable the State to update its ES plans and to expand ES at the appropriate time.

The reviewed literature and this report's analysis provide the details and the relatively consistent installed costs of existing ES installations worldwide. Estimates vary and technology costs from non-New Jersey studies are highly variable and often appear to be low, incompletely referenced, and incomplete. New Jersey-specific costs by ES technology and application are difficult to estimate due to the historical lack of installations in New Jersey. The stakeholder processes included as part of this analysis provided partial, but insufficient, data regarding New Jersey-specific costs of ES. More New Jersey-specific, accurate and detailed ES cost estimates of installation are needed to inform New Jersey's ES plan.

While this report has made use of the best available cost estimates for ES installations, the next phase of the pilot program should collect more New Jersey-specific cost data, related to installation and integration.

Achieving the State's objectives requires developing and implementing an ES plan integrated cost-effectively with the rest of the State's Energy Master Plan (EMP). ES – like demand response (DR), energy efficiency, renewable resources, non-carbon emitting resources, smart grid technology, and EV – is vital to a clean energy economy. Energy Storage is both a complement and a substitute for generation, transmission and distribution (T&D) assets and therefore interacts with the electric power system in complex ways. At the time of the drafting of this report, the State has several important parallel initiatives that affect the economics of ES including, but not limited to, the following policies: Electric Vehicles, zero-emission credits, OSW development and the State's Offshore Wind (OSW) Strategic Plan, energy efficiency and DR programs, solar, and utility hardening. The outcome of these policies affects the type, amount, location, timing and applications of ES. Evaluating the economics of ES in concert with all of the other State's clean energy initiatives is a major challenge, which requires a holistic and integrated approach and granular data.

This ESA report covers a high-level analysis of ES integration to the power grid. The next phase of the ES program should integrate the analysis with other ongoing initiatives in New Jersey and regionally.

Capturing the broader impacts and economics of ES installation necessitates accurate network interconnectivity data at the bulk and distribution levels, high-resolution load data at customer sites, number of industrial, commercial and residential facilities and their prioritizations for resiliency purposes. Furthermore, cost estimates for avoided T&D costs were not available and can vary substantially by location on the grid or distribution system. Having accurate and location-based avoided T&D costs is critical to determine where to locate ES projects.

With no access to such accurate system wide data, this ESA report covers: (i) customer site analysis for 24 representative commercial and industrial facilities with publicly available data; (ii) sample distribution networks which were proposed as part of another New Jersey BPU study, and (iii) high level bulk analysis aiming at the integration of OSW and ES.

Highlights of Policy Recommendations

Energy storage can serve many applications, only a few of which are currently attractive to investors unless they receive incentives or if the State enacts regulatory reforms that permit business models to succeed across regulated and market-based revenue streams. Therefore, key related questions for the State of New Jersey are:

- *What are the highest priorities for our energy future?*
- *Which applications would advance these priorities if they achieve widespread deployment?*
- *How can New Jersey cost-effectively learn about this set of technologies?*

Maximizing the value of ES for ratepayers and the State depends on the ability to stack revenues and value streams as discussed in CEA Element 1 of this report. State policies need to adequately compensate those ES projects that provide multiple benefits across wholesale electricity markets (e.g., energy arbitrage), federal and state regulatory policy (e.g., avoided T&D), and broader public policy goals (e.g., resiliency and air emission reductions). Such a policy analysis is beyond the scope of this report, and our understanding is that discussions among New Jersey BPU staff are underway.

Engagement with PJM is needed to ensure market rules work to animate the full value of storage in wholesale markets and to compensate ES (most likely aggregated) for providing grid benefits.

Our key findings (including comments and responses from stakeholders) suggest that the following types of incentives will benefit New Jersey:

<u>Resiliency related incentives:</u>

- Incentives to place ES in grid areas with major critical facilities.
- Incentives to deploy fully integrated, modular mobile ES with quick connect capability for various applications in normal circumstances but must be made available for deployment in emergency resiliency operations.
- Incentives for adding ES to PV arrays that exist or might be added at public schools and other sites that could be sheltering/gathering places during extended grid outages.

<u>Renewable related incentives:</u>

- Additional incentive package for ES tied with renewables especially in limited transmission areas of the State which cannot assume excessive loads of renewable energy influx at peak times.
- Incentives to place bulk level ES to recover OSW power in case of limited transmission line capacity.
- Incentive package for ES tied with renewables in the distribution network to increase renewable hosting capacity, help reduced peak load and improve resilience for critical facilities at the distribution network level.

EV related incentives:

- Additional incentives to place ES that enables massive EV charging at public sites such as transit hubs, airports and massive carparks with overnight vehicle parking. Also, commercial and industrial (C&I) sites are advantageous to adopt EV fleets (e.g., trucking industry, transportation network companies, universities and colleges).
- Incentives for ES installations that take advantage of used batteries from EVs and other applications. An additional benefit will be to reduce the environmental footprint of used batteries.
- Incentives for ES installations that advance the State's overall clean energy agenda, reduces carbon emissions and drives New Jersey to the forefront of energy innovation (e.g., EV parking facilities powered by PV and ES).
- Encourage development and deployment of vehicle-to-home (V2H) and vehicle-to-grid (V2G) installations that can provide additional grid resilience value at the residential level and in fleet configurations. Fleet deployments may be more effective at bringing entrepreneurial car manufacturers to the table to provide V2G/V2H options.

General purpose incentives:

- Waiver or reimbursement of associated state, township and county fees (including general construction).
- Incentives to install modular, vertically integrated ES systems to minimize footprint.
- Incentives for dual use cases (e.g., utility or municipality owned but located on private properties).
- Incentives for ES installations with new business models (e.g., EV parking garages in brownfields and powered by PV) that help bring clean energy to economically deprived areas.
- Incentives for installations that allow access to data and research and development (R&D) for further technological development (e.g., living laboratory concepts).

Maximizing the value of ES for ratepayers and the State depends on the ability to stack revenues and values streams as discussed in this report. State regulatory policies need to adequately compensate those ES projects that provide multiple benefits across wholesale electricity markets (e.g., energy arbitrage), federal and state regulatory policy (e.g., avoided T&D), and broader public policy goals (e.g., resiliency and air emission reductions).

The remainder of this document discusses the technical approach, and the report's findings and recommendations particular to each of the nine CEA elements.

Technical Approach

This ESA takes lessons from New York and Massachusetts studies as its starting point and places emphasis instead on a series of bottom-up ES applications that have been less well studied. This acknowledges the New Jersey context as a medium-sized state within the very large PJM electrical region, which has already created a thriving, if highly specialized, ES market for FR and other ancillary services. In contrast, New York has its own New York Independent System Operator (NYISO) whose borders are contiguous with those of the State, and Massachusetts is the dominant player in ISO New England (ISO-NE), so their studies need to prioritize the bulk power perspective.

This section continues with synopses of main definitions and assumptions, followed by project tasks and methodology, a thorough discussion on emissions and ES, and finally comparisons to previously completed works in New York and Massachusetts.

Synopsis of Main Definitions

- Facility or customer site – consists of a single building (commercial, industrial or residential).
- Facility peak load – maximum annual peak load of a facility in kW.
- Load Loss – facility's unserved demand during outage events.
- Short Duration Outage – one to four hours power grid outage (gray sky condition)
- Long Duration Outage – one to seven days power grid outage (black sky condition).
- Normal operation – uninterrupted power grid operation (blue sky condition).
- Resilience – The ability to serve critical/vital power demand.
    - Critical load – enables a facility to serve its necessary functions.
    - Vital load – power required for minimum functionality.
- Energy storage capacity – expressed in kW, MW or % of peak load throughout this report.
- Energy storage duration – expressed in kWh or MWh.
- Centralized energy storage – the storage is installed at a single site (e.g., substation) and operated by a utility company.
- Decentralized energy storage – energy storage installation is only allowed behind-the-meter for a single bus connected to a load.
- Electric Bill Management (EBM) – it includes two main applications, namely time-of-use (TOU) energy cost saving, and demand charge saving due to peak load shaving.

Synopsis of Main Assumptions

- Distribution network analysis do not consider available hosting capacity for net metering applications. Hence, behind-the-meter facility level PV and/or ES installations do not follow net metering.
- CAPex = varies depending on the system.
- Fixed OPEx = $10 /kW-year
- Cost of solar panels = $2000/kW.

- Lithium-ion with 85% roundtrip efficiency is the main energy storage technology in this study. Some sensitivity analysis carried out.
- Battery self-discharging is included in the analysis.
- Wholesale price of electricity is based on 2018 PJM data.
- All recommendations are made on the basis of new ES installations.
- Facility outage data is based on data published by EIA database.

Project Tasks and Objectives

Three main tasks were defined to address the **ESA elements** mentioned above:

- ***ES Technology Evaluation***

  This task characterized and compared commercially available and near commercially available ES technologies explicitly applicable to grid level implementation, with a particular emphasis on technologies with proven implementation. This task also established a baseline of the implementation level of each ES technology as well as the ES technology implementation levels necessary to meet the ES requirements. This task evaluation included an estimate of the scalability, capital installed cost, lifetime cost, robustness of implementation, portability, energy, and power densities of the ES technologies.
- ***ES Analytics and Network Level Evaluation***

  This task determined the potential benefits of ES technology for grid resiliency, offsetting peak loads, charging EVs, and stabilizing power distribution networks and market products such as FR. Power distribution network stabilization focused on reducing and better managing grid impacts of DER, variable energy resources, EV penetration, and distribution network investment deferral. The analysis utilized actual data (if available) or simulated data. The optimal point of entry to the distribution network for each ES was calculated using localized and distribution network impacts of ES. The analysis also investigated the location and sizing of ES at the facility, regional and network levels.
- ***ES Economic Assessment***

  This task performed a detailed and comprehensive cost-benefit analysis (CBA) over the timeframe between 2018 and 2030, based on selected ES technologies identified in this project, the locations, integration and the values of the benefits and costs identified in the above tasks. The CBA outcomes were described using attributes of affordability, flexibility, reliability, resilience, security, and sustainability.

A multi-dimensional analysis approach was employed to determine applications of several ES technologies and their benefits and costs. The findings associated with ES technologies/applications were incorporated into RU-LESS analytical platform to determine the integration impact of ES technologies for facilities, distribution networks, and bulk systems. The analysis also evaluated ES applications for EVs. The economic assessment was conducted for the effective timeframe (2019 to 2030) via CBA informed by the U.S. Department of Energy (US

DOE) Energy Storage Computational Tool (ESCT) to investigate the costs and benefits derived from ES technology for the State of New Jersey. The analysis covered the cost of ES technologies and their infrastructure investments, including installed costs, fixed operations and maintenance (O&M) costs, battery efficiency and availability, and applicable federal incentives.

ES Technology Evaluation

Although pumped hydroelectricity, a form of mechanical energy storage, currently dominates the ES landscape with 96% of global capacity, several other electrical energy storage technologies exist. Electrical energy storage possesses beneficial attributes needed to provide improvements to the grid's infrastructure economic profile, but also its overall reliability, stability and flexibility. As such Figure 1 lists the various mechanical, electrochemical, thermal and chemical technologies evaluated in this report under the ESA umbrella. Indeed, it is improbable that a single electrical energy storage technology can address all issues of the current grid infrastructure or serve all markets at once. Instead, a portfolio of several technologies with distinct intrinsic technical properties that determine their suitability for specific applications/services is the most effective way to achieve an upgraded grid capable of enduring the demands of the future. It is critical to determine which of these electrical energy storage technologies are most suitable for applications specifically within the State of New Jersey.

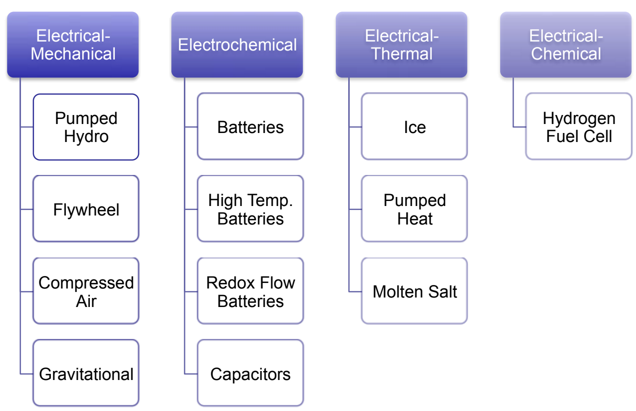

Figure 1: List and classification of all electrical energy storage technologies evaluated in the ESA program

Our methodology was organized to relay a top-level technical description of a broad array of electrical energy storage technologies viable for utility applications, including:

1. Operating principles
2. Performance characteristics
3. Viability to address range of in front and behind-the-meter applications
4. Case studies
5. Projections

A combination of case studies analysis, stakeholder survey analysis, and a literature review formed the basis of the electrical energy storage assessment of the listed portfolio of electrical energy storage technologies. The case studies were based in New Jersey, the United States, and internationally, to provide the most extensive and recent results. For each electrical energy storage technology, the focus in the case studies targeted the following set of parameters:

1. Installation scale
2. Technical performance
3. Services and applications
4. Environmental impact
5. Cost

The goal was to establish current and future best practices from a set of data based on ES stations already installed or currently under construction corroborated by literature. Our RU LESS modeling/simulation utilized a selection of the electrical energy storage technologies deemed to be the most appropriate and performed the modeling/simulation at different levels (i.e., facility level or customer site, distribution system and bulk system) while serving various markets to determine the optimal implementation of these electrical energy storage technologies in the grid infrastructure of New Jersey.

ES Analytics and Network Level Evaluation

Using technology parameters from the Technology Evaluation Task, this task utilized the RU LESS modeling tool[1] and analytics to estimate the value of ES in different use-cases (i.e., facility level or customer site, distribution system and bulk system). Lithium-ion (Li-ion) batteries were the primary technology used in the ES analysis, with sensitivities run around battery efficiency. Several case studies were also conducted using a sensitivity analysis on ES roundtrip efficiency and discharge durations that can be mapped to relevant storage technologies with the same attributes.

The evaluation of the different scenarios utilized a comprehensive experimental design. Facility-level analysis focused on three applications: Electricity Bill Management (EBM), resiliency for short durations (i.e., within four hours) and resiliency for extended durations (i.e., in days). The evaluation ran different scenarios that included ES, ES with PV, ES with diesal generation (DG) and ES with both PV and DG. Electricity Bill Management determines the impact of ES on customer (i.e., commercial or industrial) bill in terms of demand charge and Time of Use (TOU). Resiliency for both short and long duration outages determines average avoided load loss (kWh) or expected energy not served per event. The analysis utilizes a variety of simulated, representative facilities, including ten (10) commercial facilities, eight (8) industrial facilities, and six (6) DoE Reference models as listed in Table 1.

[1] A. Ghofrani, F. Farzan, J. Swartz, K. Mahani, N. Balsami, P. Ansari, M.A. Jafari. 2016. “Cyber physical simulation of energy smart communities.” (Presented at the International Conference on Smart Infrastructures. 27–29 June 2016, n.d.: pp. 663–667. doi:10.1680/tfitsi.61279.663).

Table 1: List of facilities studied.

DOE Reference Model	NJ Commercial Facility	NJ Industrial Facility
Hospital	College	Fabricated Metal (1 shift)
Hotel	Fire Station	Fabricated Metal (2 shifts)
Office	Hospital (275 bed)	Food Processing
Midrise Apartment	Hospital (450 bed)	General Manufacturer
Secondary School	Middle School	Pharmaceutical
Supermarket	Office	Plastic Manufacturer
	Pump Station	Services
	Residential	Warehouse
	Supermarket	
	Wastewater Treatment	

For DOE Reference Models, the loads are all normalized to 1MW peak demand for a better comparison in CBA (the other facilities are not normalized). Figure 2 illustrates an average daily load profile behavior in cooling season for the above facilities. The following facility profiles were assumed:

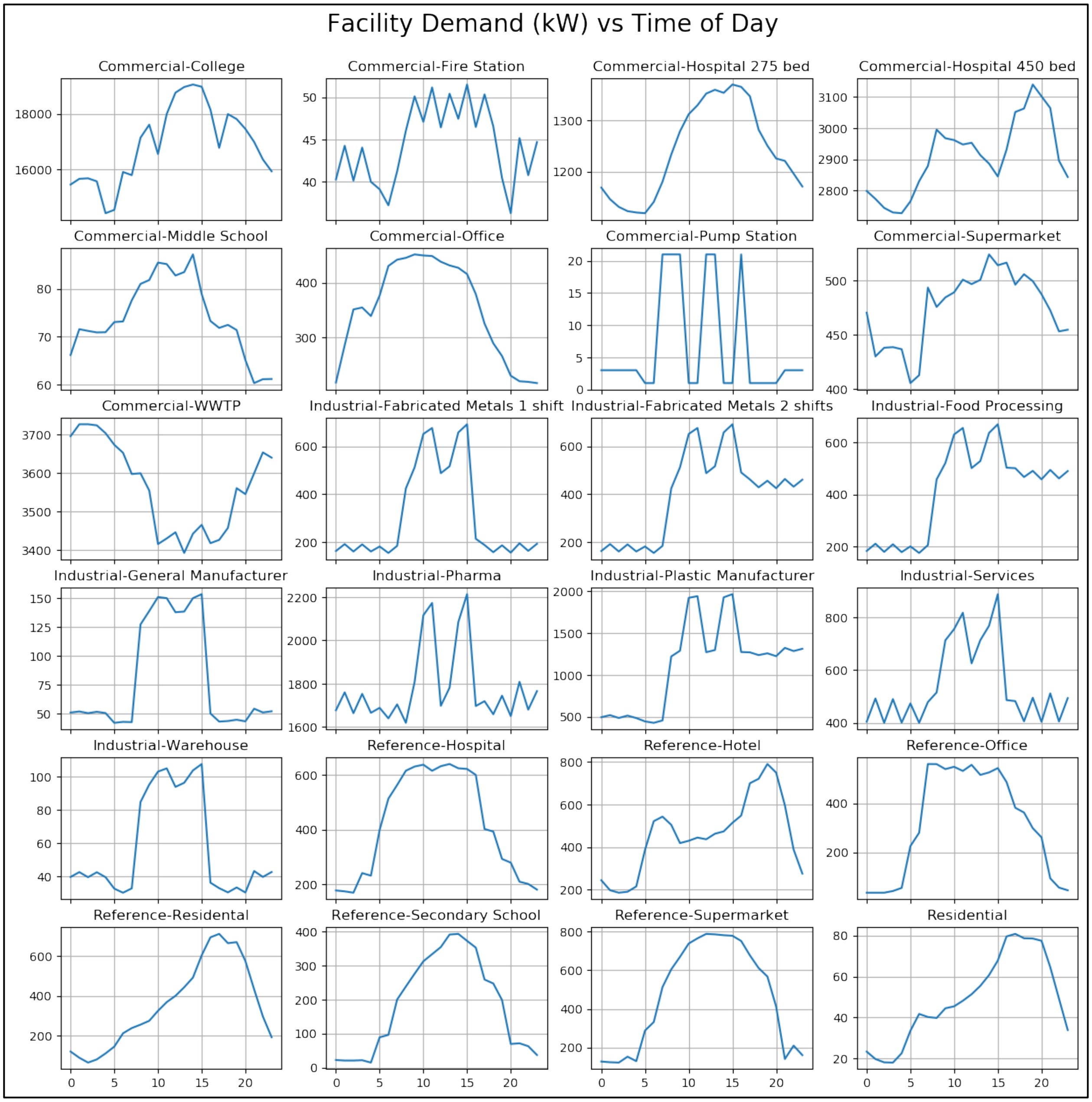

Figure 2: Load profile for the 26 facilities in cooling design day.

Distribution level analysis was performed: i) to evaluate the impact of ES on renewable generation investment (mainly PV and how ES supports renewable power penetration) in a distribution network; and ii) to conduct network simulations with ES/PV and the following configurations:

1. Decentralized PV systems with or without ES across the distribution network assuming that there is no available hosting capacity (no net metering).
2. Centralized configuration at the grid interconnection for ES only and ES+PV systems.

The analysis above evaluated the impact of ES-only and ES+PV configurations on the resiliency and the network capability for peak and power import reduction. The analysis was performed for three different simulated network configurations located in different New Jersey electric distribution company (EDC) territories described below:

1) *Nine-node Network* - A nine-node network located in East New Jersey with 2.5 MW of peak demand and 12 GWh of total consumption.

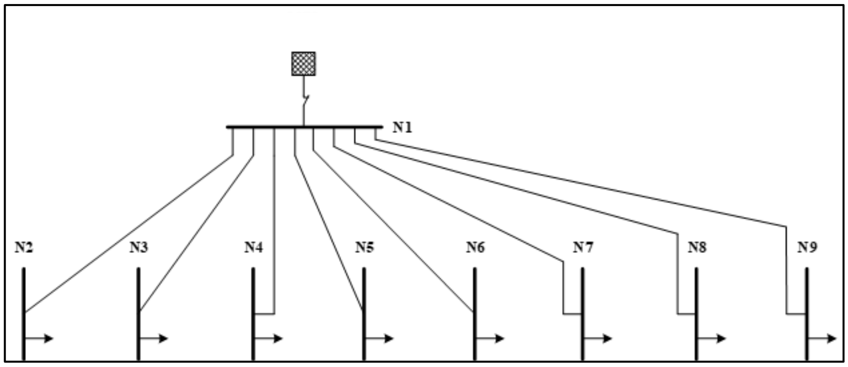

Figure 3: Nine-node Network topology.

2) *Twelve-node Network*– A twelve-node network located in Northeast New Jersey with 1.4 MW of peak demand and 4.5 GWh of annual consumption.

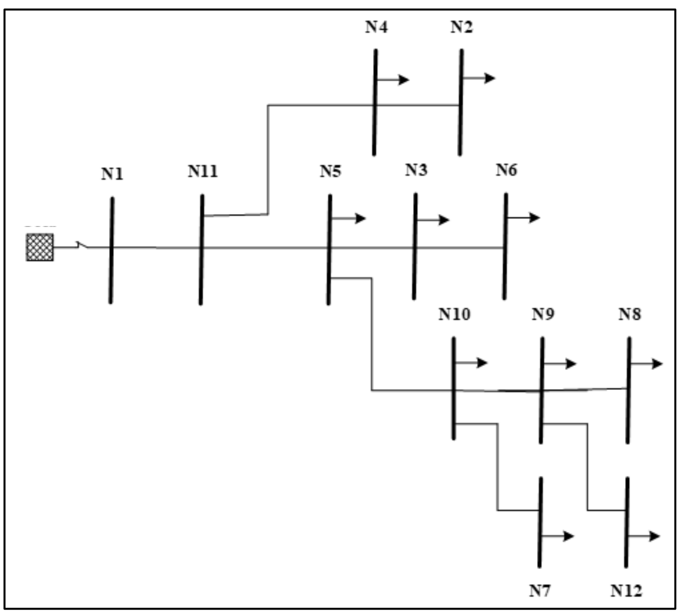

Figure 4: Twelve-node Network topology.

3) *Seventeen-node Network*- A simulated seventeen-node network located in South New Jersey with 3.4 MW of peak demand and 14.4 GWh of total consumption.

Note that the tie-line in this network is planned to be energized during long-outage scenarios.

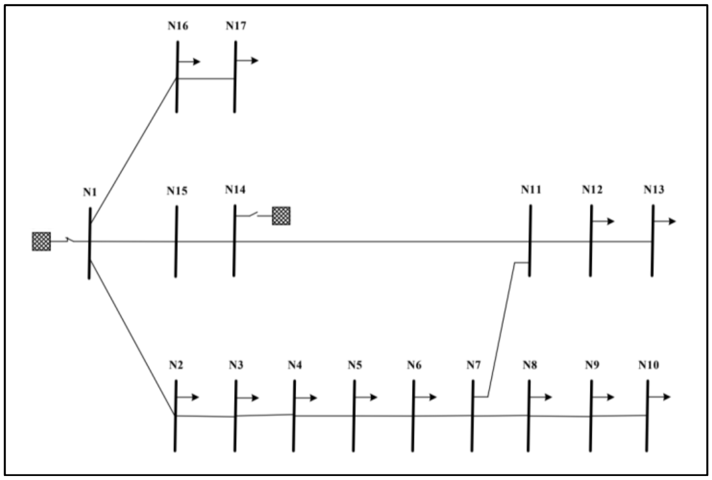

Figure 5: Seventeen-node Network topology.

The evaluation included an analysis of bulk power systems, revenue streams for the FR market, capacity market, and arbitrage market at different ES rated capacities, durations, and efficiencies (attributed to different Li-ion storage technologies). Sensitivity analysis was performed to determine the impact of efficiency on revenue streams for bulk power systems, EBM, and resiliency. The impact of ES integration with OSW on New Jersey transmission network and how ES can help T&D deferral and recover wind power generation were also analyzed. The evaluation ran unit commitment models with county-level granularity, and average LMP prices reported for each county before and after ES integration with OSW.

ES Economic Assessment

This section of the study provides a CBA of a range of scenarios and applications for ES. CBA compares the monetized value of the costs of a project to its benefits, accounting for the time value of money (with a discount rate). CBA is a standard tool of economic analysis used to evaluate technologies, projects, and regulatory policies. A literature review of studies commissioned by five states, the U.S. Energy Information Administration (EIA), and the Energy Storage Association also supports the CBA.

Cost-benefit analysis generally provides two key metrics for evaluating projects – the benefit-cost ratio (BCR) and the net-present value (NPV) of the investment. The BCR (i.e., benefits divided by costs) indicates whether benefits are higher than costs. Projects with BCRs above 1.0 are generally considered good investments, while those with ratios below 1.0 are not expected to generate monetary returns in excess of their costs.From an *investor's perspective*, an ES project that produces discounted revenues and/or cost savings in excess of its costs will have a BCR greater than 1.0, while one with revenues and/or cost savings lower than its costs will have a BCR less than 1.0. However, the project may have additional benefits that accrue to various parties in addition to the investor. For example, reduced pollutant emissions benefits society as a whole (rather than the investor), including populations outside the area where the power is generated or consumed. Similarly, the benefit of avoided outages may accrue to either the investor/owner of a resiliency resource such as ES (e.g., a supermarket or restaurant avoids food spoilage, affecting their bottom line) or to a broader constituency (e.g., patients at a hospital avoiding morbidity, residents benefiting from a local warming center, etc.). Incorporating these additional benefits into the BCR or considering them as an added value to be captured can in some cases increase the value of the benefit stream, resulting in a higher BCR when a project is viewed from a *societal perspective*. In some cases, such as bolstering the energy resiliency of a facility, this value of lost load (VOLL) may be relevant to both benefit-cost perspectives.

Cases where the investor's benefits are lower than the costs require a monetary incentive for the project to be potentially viable and attractive from the investor's perspective. This gap (or surplus, if the benefits are higher than the costs) represents the NPV of the project.

The focus of the analysis is on Li-ion batteries, with several additional simulations conducted for other ES technologies.

Costs

The Lifetime adjusted costs included in the analysis are:

- Upfront capital expenditures (CapEx)
- Lifetime operating and maintenance (O&M) expenditures – set at $10/kW/yr[2]
- Investment tax credit (ITC) and accelerated depreciation (i.e., offsets to CapEx)
- Change in taxes due to change in net operating costs (i.e., reduction in demand charges and energy costs, added O&M costs)

Benefits

Lifetime project benefits included in the analysis are:

- Avoided demand charges (used as a proxy for avoided T&D)
- Avoided energy costs
- Frequency regulation revenue
- Arbitrage revenue
- *Non-financial benefits*[3]
    - *Value of avoided outages*
    - *Value of net change in emissions (may be negative)*

The last two "non-traditional" benefits are somewhat separate from the more tangible financial benefits that include avoided costs and additional revenues. The initial BCR is calculated as total financial benefits (i.e., not including the value of avoided outages and value of emission reduction) divided by total costs. If this BCR is less than 1.0, then lifetime costs exceed lifetime benefits, and the NPV of the investment in ES represents the financing gap that would need to be closed by an incentive in order to render the project financially viable. Capital costs

[2] Estimate based on figures cited in prior studies, which find ranges of $6-$14/kW/yr. See, for example: Todd Aquino et. al. 2017. *Energy Storage Technology Assessment*. (Prepared for Public Service Company of New Mexico by HDR Inc. HDR Report No. 10060535-0ZP-C1001 https://www.pnm.com/documents/396023/1506047/11-06-17+PNM+Energy+Storage+Report+-+Draft+-+RevC.pdf/04ca7143-1dbe-79e1-8549-294be656f4ca); and Michael Kleinberg. 2016. *Battery Energy Storage Study for the 2017 IRP*. (Prepared by DNV GL for Pacificorp. DNV GL- Document No.: 128197#-P-01-A http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/10018304_R-01-D_PacifiCorp_Battery_Energy_Storage_Study.pdf).

[3] Non-financial benefits represent those that might not be directly realized by the investor.

are considered to be up-front costs, while O&M costs and benefits occur over the life of the battery. For grid-level projects, this gap is effectively the cumulative impact on ratepayers.

The Value of Avoided Outages and the Value of Net Change in Emissions represent additional benefits to the customer (i.e., Value of Avoided Outages) or society (i.e., Value of Net Change in Emissions) that could be captured if the ES were in place, but which do not necessarily affect the financial parameters for a given investment. The extent to which these values offset a negative NPV (i.e., and hence raise a sub-1.0 BCR closer to 1.0) can inform decision-making as to the desirability of investments that may require subsidies in order to be viable. The Value of Avoided Outages is effectively a proxy for the value of resiliency in these applications. While the VOLL – the estimated dollar value per MWh not served that is used to calculate the Value of Avoided Outages – may be high in some applications, often at the facility-level the short duration and low frequency of outages may result in relatively low total resiliency value.

Computing VOLL is a challenging task because there are several alternative theories of value that appear in the literature. Some estimates focus on the value of production lost due to electricity outages, such as spoiled food in the refrigerator and damaged chips in a semiconductor foundry.[4] Others emphasize customers' expressed willingness to pay to avoid outages, based on hypothetical scenarios posed in survey questionnaires.[5] A third method relies on revealed preferences, looking at actual expenditures on back-up generators as the basis for estimating the willingness to pay for avoiding outages.[6] These methods vary by orders of magnitude in their estimates of the value of avoiding unserved energy. More recent studies typically recommend that the lost load be disaggregated as much as possible by customer type and energy end use, because the value of avoiding unserved energy depends so strongly on the duration of the outage, its frequency of occurrence, the available substitutes, and the criticality of the consequences if an outage occurs.[7] In practical terms, three questions need to be asked:[8]

- "Is it feasible to postpone delivery of this end use for a few hours, or must it be continuously available?
- Are there any affordable and convenient substitutes for this end use?
- Are the consequences of going without this end use significant in terms of human health or economic costs, or are they minimal?"

In the current study, we differentiate the VOLL by sector, and within the engineering-level models of different sectoral cases, we distinguish critical loads from non-critical loads. We also assume that ES alone (according to findings from analysis) can only serve critical loads for a

[4] R. Anderson and L. Taylor. 1986. The social cost of un-supplied electricity: A critical review. (*Energy Economics* 8(3): 139-146. https://doi.org/10.1016/0140-9883(86)90012-5).
[5] A. Sangvi. 1982. Economic costs of electricity supply interruptions. (*Energy Economics* 4(3): 180-198. https://doi.org/10.1016/0140-9883(82)90017-2).
[6] M. Beenstock. 1991. Generators and the cost of electricity outages. (*Energy Economics* 13(4): 283-289. https://doi.org/10.1016/0140-9883(91)90008-N).
[7] C. Andrews. 1992. An end-use approach to reliability investment analysis. (*Energy Economics* 14(4): 248-254. https://doi.org/10.1016/0140-9883(92)90029-D).
[8] J. Senick, D. Birnie, A. Trehan, N. Chen., and D. Plotnik. 2015. *Highland Park Solar Islanding Project*. (Report prepared for Sustainable Jersey. Pg. 10. Available at http://rcgb.rutgers.edu/highland-park-solar-islanding-project/).

few hours at most. However, when coupled with PV, ES can serve critical loads for a much longer period.

We used residential (for apartments) and median sectoral estimates of VOLL for the United States for large commercial and industrial customers (those consuming over 50 MWh per year) as reported in ERCOT (2013)[9], based on data from LBNL (2009)[10]. We inflated these values from their 2012 levels to 2018 dollars based on the U.S. Consumer Price Index. Table 2 shows these values.

Table 2: Value of Lost Load by Sector

Sector	$/MWh
Public Administration	$1,404
Services	$4,447
Finance/Insurance/Real Estate	$1,521
Trade/Retail	$15,096
Telco/Utilities	$1,638
Manufacturing	$13,107
Construction	$14,160
Mining	$7,958
Agriculture	$4,213
Residential	$117

The analysis did not find VOLL estimates for all represented sectors. As proxies, we applied the VOLL for public administration to the case of secondary schools, and the VOLL for trade/retail enterprise – the highest value – for hospitals. Given the potential effects on health, the true VOLL for hospitals may be higher. At the same time, existing back-up generation and existent redundant battery systems may mitigate the potential of these losses and hence the value of ES back-up.

[9] London Economics International, LLC. 2013. *Estimating the Value of Lost Load*. (Briefing paper prepared for Electric Reliability Council of Texas, Inc., June 2013).

[10] Michael J., Sullivan, Ph.D., Matthew Mercurio, Ph.D., Josh Schellenberg, M.A Freeman, Sullivan & Co. 2009. *Estimated Value of Service Reliability for Electric Utility Customers in the United States.* (Prepared for Office of Electricity Delivery and Energy Reliability U.S. Department of Energy by Ernest Orlando Lawrence Berkeley National Laboratory, June 2009).

We examined the costs and benefits of several different applications of ES:

- Resiliency at the facility level
- Energy market participation – frequency regulation and arbitrage
- Resiliency/renewable support at the distribution level

We also tested the viability of a selected range of alternative storage technologies.

Emission

Energy storage will affect the air pollution emissions profile of the regional electric power system when installations reach a significant level. If emissions drop, that will count as a non-economic benefit to society from ES. The considerations in calculating this benefit are as follows:

- What is the difference in emissions rates between the electricity used for charging ES and discharging ES?
- What is the round-trip efficiency of ES?
- What is the unit value of avoiding emissions?

Peak vs. Off-peak Emissions Rates

Energy storage will typically charge during the electricity system's off-peak hours and discharge during peak hours. In calculating avoided emissions, it is important to distinguish between average and marginal emissions. Average emissions are the emissions from all power plants operating during a given hour, divided by the total kWh generated. Marginal emissions are from the last power plant to be dispatched at the operating margin for that hour. Energy storage displaces the marginal plant and its emissions, not the average emissions. PJM defines peak hours as all non-holiday weekdays from 7 a.m. until 11 p.m., and non-peak hours are the remaining hours.[11] Figure 6 shows historical trajectories for average, marginal peak and marginal off-peak CO_2, Figure 7 shows SO_2 emissions rates,

Figure 8 shows NO_x emissions rates, and Figure 9 shows the hourly generation mix.[12] The marginal fuel is typically natural gas during both peak and off-peak hours.

[11] PJM. 2019. *2014-2018 CO2, SO2 and NOX Emission Rates*. (pg. 3 https://www.pjm.com/-/media/library/reports-notices/special-reports/2018/2018-emissions-report.ashx?la=en).

[12] Sources for the data shown in the figures are PJM. 2019. 2014-2018 CO2, SO2 and NOX Emission Rates, Figures 3, 5, 7; and Monitoring Analytics. 2019. 2018 State of the Market PJM, Vol. 2, Section 8, Figure 8-10.

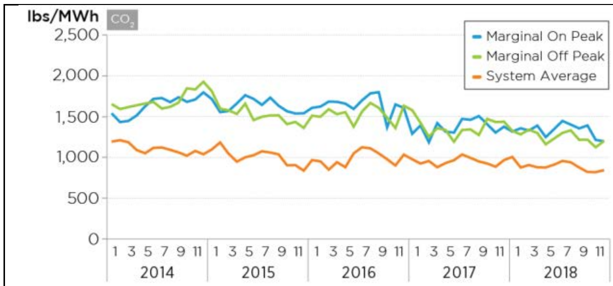

Figure 6: 2014-2018 PJM CO2 Marginal and Average Emissions Rates

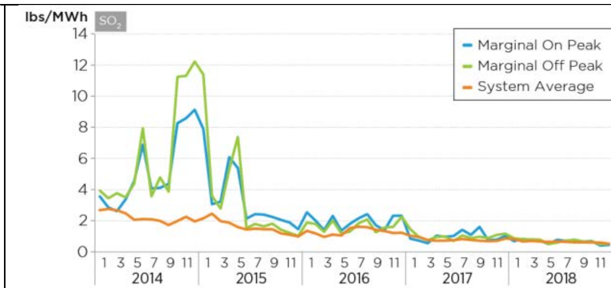

Figure 7: 2014-2018 PJM SO2 Marginal and Average Emissions Rates

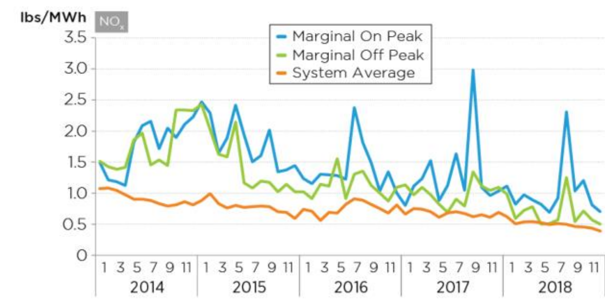

Figure 8: 2014-2018 PJM NOx Marginal and Average Emissions Rates

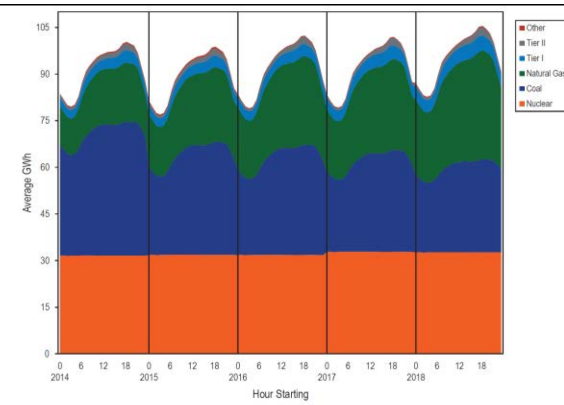

Figure 9: 2014-2018 PJM Hourly Generation Mix

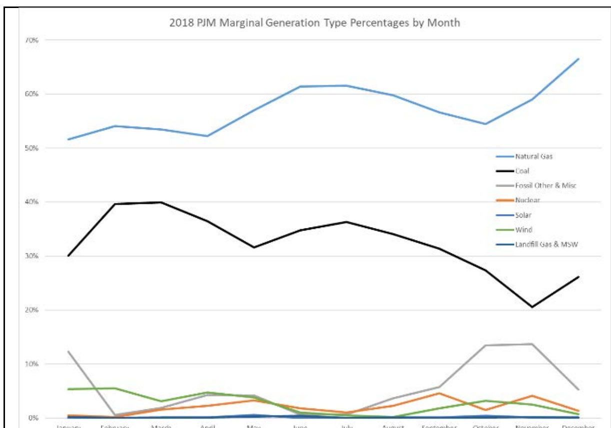

Figure 10: 2018 PJM Marginal Fuel Percentages by Month

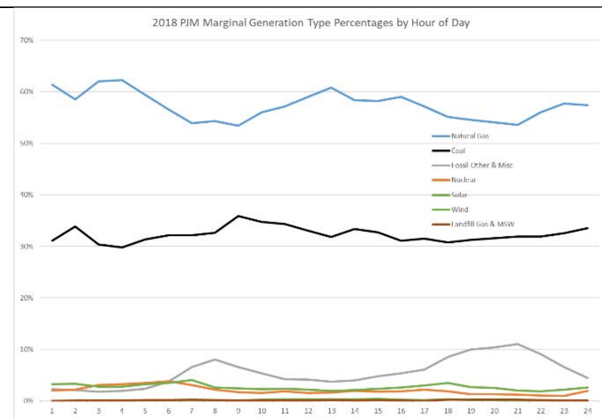

Figure 11: 2018 PJM Marginal Fuel Percentages by Hour of Day

Figure 10 shows 2018 marginal generation fuel data by month that confirm the dominance of natural gas at the margin, at the seasonal time scale.[13] Figure 11 shows the same data at the hourly time scale. Emission rates for 2018 for the PJM system are shown in Table 3.

[13] Monitoring Analytics, LLC. 2019. Marginal Fuel Posting Data (monthly for 2018).

Table 3: 2018 Peak and Off-Peak Marginal Emissions Rates for PJM System (lb/MWh)

	CO_2	SO_2	NO_x
Peak	1,338	0.66	1.03
Off-Peak	1,254	0.68	0.67

As wind and solar technologies continue to come online, the generation mix in the PJM region will eventually change significantly and so will the average emissions profiles. A reasonable guess at the 2020 and 2030 timeframes is available from the Regional Greenhouse Gas Initiative (RGGI) scenarios prepared in late 2018 for New Jersey by ICF, Inc., under subcontract to Rutgers University. Figure 12 shows the expected capacity additions and retirements in New Jersey. Figure 13 shows that offshore wind is expected to displace primarily natural gas in the New Jersey portion of the PJM generation mix.[14]

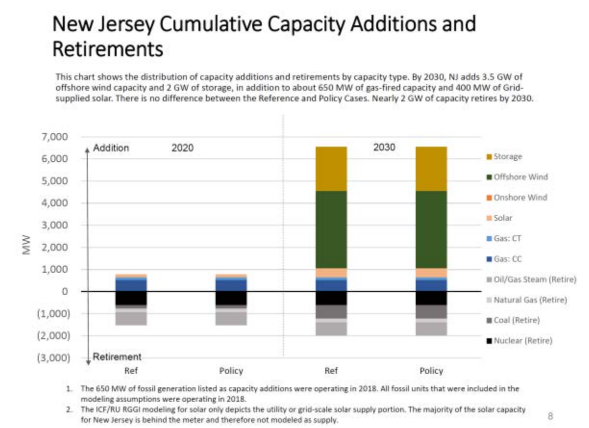

Figure 12: New Jersey Capacity Additions and Retirements 2020 and 2030 from RGGI Study

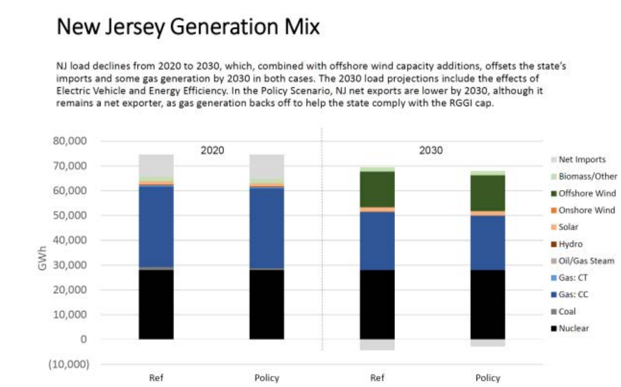

Figure 13: Jersey Generation Mix 2020 and 2030 from RGGI Study

The RGGI study suggests that New Jersey ES will still be primarily charging with and discharging against natural gas at the margin through the year 2030, although emissions rates overall ought to diminish due to the increased presence of solar and wind generation. A look at PJM as a whole shows a consistent pattern of decreasing average emissions rates in the region: "Since 2016, 93.1 percent of all new projects entering the generation queue have been either combined cycle (29.3 percent), wind (20.6 percent) or solar projects (43.2 percent)."[15] The capacity mix in PJM in 2018 was approximately 29% coal, 40% natural gas, 17% nuclear, 5% wind, 1% solar, and 8% other sources.[16] Considering retirements and additions that report shows in the queue (but not based on a formal capacity expansion planning study), the research team posits that the PJM mix by 2030 may include about 10% coal, 43% natural gas, 11% nuclear, 12% wind, 19% solar, and 5% other sources. Table 4 shows estimated 2030 peak and off-peak marginal emissions rates for PJM based on a capacity-weighted extrapolation of this trend.

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[14] ICF, Inc. 2019. RGGI Report: New Jersey Reference Case and Policy Scenario Results. Prepared by ICF for Rutgers University at the Request of the New Jersey Board of Public Utilities.

[15] Data source for these figures and table is Monitoring Analytics. 2019. *2018 State of the Market PJM*. (Vol. 2, Section 12, Pg. 585. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-sec12.pdf).

[16] Monitoring Analytics. 2019. *2018 State of the Market PJM*, Vol. 2, Section 12, Pg. 570. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018-som-pjm-sec12.pdf.

Table 4 Estimated 2030 Peak and Off-Peak Marginal Emissions Rates for PJM System (lb/MWh)

	CO_2	SO_2	NO_x
Peak	740	0.22	0.51
Off-Peak	693	0.23	0.33

Thus, as in 2018, in 2030 ES will not avoid many emissions by charging off peak and discharging on peak. Similar findings appear in recent studies in other states including New York[17] and Massachusetts.[18] However, ES could have much more value as an emissions reducer if it is used as a tool to facilitate environmentally-optimized dispatch of power plants.[19]

Round Trip Efficiency of Energy Storage

Energy storage carries an efficiency penalty relative to electricity generation because energy must be stored and later retrieved. For a round trip that includes AC-to-DC-to-AC conversions, the research team believes 85% is a reasonable assumption.

Value of Avoiding Emissions

This study uses the unit avoided pollution emissions cost estimates developed for the New Jersey Clean Energy Program.[20] These are literature-based values derived from the *U.S. Environmental Protection Agency's (EPA) 2016 Social Cost of Carbon Study* and *National Research Council's (NRC) 2010 Hidden Costs of Energy Study* and inflated to 2018 dollars. Table 5 shows the values used in this study.

Table 5 Value of Avoided Emissions (2018 $ / lb emitted)

CO_2	SO_2	NO_x
$0.02	$2.81	$0.77

[17] "Analysis shows relatively modest carbon reductions in the near term by charging energy storage with grid electricity during off-peak hours at night and discharging during afternoon peak hours." (Page 34, New York State Energy Storage Roadmap and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations, filed in Case 18-E-0130, In the Matter of Energy Storage Deployment Program).

[18] "In the total benefits and benefit-cost ratios presented below, non-embedded environmental costs are set to zero…" Page 21, also see Table 15, in Elizabeth A. Stanton. 2018. Massachusetts Battery Storage Measures: Benefits and Costs, Report AEC-2018-07-WP-02 prepared by Applied Economics Clinic, which is Appendix 1 in Todd Olinsky-Paul. 2019. *Energy Storage: The New Efficiency How States can use Energy Efficiency Funds to Support Battery Storage and Flatten Costly Demand Peaks*. (Report prepared by the Clean Energy Group.

[19] Page 34-38, New York State Energy Storage Roadmap and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations, filed in Case 18-E-0130, In the Matter of Energy Storage Deployment Program).

[20] Rutgers Center for Green Building. 2018. *Energy Efficiency Cost-Benefit Analysis Avoided Cost Assumptions Technical Memo, November 2, 2018 Update*. (Memorandum prepared for the New Jersey Clean Energy Program).

Monetized Benefit of Avoided Emissions

The full benefit calculation includes (1) determining peak and off-peak marginal emissions rates in each year, (2) taking the difference in rates each year, (3) calculating the total emissions difference in each year, (4) adjusting for round trip efficiency, and (5) applying the unit value of avoided emissions to the difference in amounts to yield a total dollar value.

Comparing Recent Studies by New York and Massachusetts to this Study

Energy storage policies are under development in several states and at the federal level, hence there are opportunities to learn from others. Here, the research team focuses on two exemplars in the region: New York and Massachusetts. In the Massachusetts case, there is also a detailed critique available.

New York

New York State Energy Storage Roadmap and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations. Filed in Case 18-E-0130, In the Matter of Energy Storage Deployment Program. June 21, 2018.

This comprehensive analysis of ES informs the development of one pillar of New York's Reforming the Energy Vision, a Cuomo administration initiative. The study addresses ES potential at customer sites, in electricity distribution system applications, and in the bulk power system. It employs multiple analytical strategies to address these different types of applications.

Most broadly, the New York study conducts an optimization exercise using an electric power system capacity expansion planning tool in which ES is available for selection as a capacity option. The tool divides New York State and its coincident regional power market (NYISO) into several zones and optimizes both capacity expansion (investments in assets) and production costing (hourly operations) within simplified transmission constraints, market rules, and environmental regulations.

The consultant Acelerex analyzes two policy scenarios designed to achieve 50% renewable generation, a 40% greenhouse gas (GHG) emission reduction, and retirement of the Indian Point nuclear plant (in 2021) by 2030, one with and the other without ES. The difference between the scenarios forms the basis of claims in the report of substantial savings to ratepayers from greater deployment of ES for bulk power applications. For 2030 the model selects 154 MW of short-duration storage (30 minutes), 467 MW of medium short-duration storage (2 hours), 714 MW of medium long-duration storage (4 hours), and 1,447 MW of long duration storage (6 hours), totaling 2,795 MW and delivering 12,557 MWh. Modeled costs (relative to the without-storage scenario) are $1,902 million. Modeled benefits include ancillary services ($140 million), capacity value ($732 million), distribution savings ($1,410 million), reduced fixed operations and maintenance costs ($214 million), generation cost savings ($550 million), and avoided CO_2 emissions ($44 million), totaling $3,090 million, for a net benefit of $1,188 million. These encouraging results depend on assumptions that (1) energy storage assets are allowed to participate fully in both retail and wholesale markets by means of asset stacking, (2) capacity costs are more than halved by 2030 (e.g., from $1,800/MW in 2018 to $722/MW in 2030 for 4-hour storage), and (3) the 50% renewables scenario by 2030 must be achieved.

The New York study also examines several use cases to assess the relative value of various customer-sited applications and distribution system applications. Customer-sited use cases include several customer types (e.g., commercial office, high-rise multifamily, school, supermarket, industrial, wastewater treatment, residential, and workplace EV charging), and different utility services territories. Distribution system applications include ancillary services, deferred distribution capacity investments, and distributed generation in different utility service territories. Many analytical details, such as load shapes and peak load magnitudes, are not provided in the report, but it has good detail on rate structures.

Analysis of use cases takes the unusual step of presenting results in units of Breakeven Installed Cost of Storage (BICO) that measure only benefits ($/MW-yr or $/MWh, higher is better) rather than also calculating associated costs (which would then allow benefit-cost analysis). If costs follow the trajectory of Li-ion price decline as discussed in the bulk power discussion above, then, for many of these use cases, benefits do not exceed costs until installation dates close to the year 2030. Specifically, costs exceed benefits in the 2019-2025 timeframe for most bulk power system applications, most distribution-level applications except in the highly urbanized Con Ed territory, and most up-state customer-site applications.

Finally, the New York study includes a substantial policy analysis authored by New York State Department of Public Service and New York State Energy Research and Development Authority (NYSDPS/NYSERDA) staff. This includes detailed recommendations on retail rate actions and utility programs, utility participation in this market, market acceleration incentives, reduction of soft costs, pursuit of a "clean peak" policy objective, and wholesale market actions.

The New Jersey and New York studies share similar ES capacity cost reduction trajectories, environmental benefit estimates, and positive findings regarding coupled PV+ES systems relative to standalone ES. They differ in their quantification of benefits, such that New York finds greater energy and demand bill savings and DR payments than in New Jersey, especially in the highly urbanized and expensive Con Ed territory. New Jersey results are more similar to Upstate New York results.

Massachusetts

Massachusetts Department of Energy Resources and Mass Clean Energy Center. *State of Charge: A Comprehensive Study of Energy Storage in Massachusetts.* September 27, 2016. https://www.mass.gov/service-details/energy-storage-study.

Massachusetts has completed a comprehensive analysis of ES options, challenges, and policy alternatives that innovates in several ways. Like New York, the Massachusetts analysis includes an optimization study at the bulk power level. Alevo Analytics, a consulting firm, has developed a capacity expansion and production costing model of electricity generation that includes detailed transmission constraints within Massachusetts, while dispatching power plants at the ISO-NE regional level. First they run a base case without new ES. Then they introduce ES (Li-ion sized at 1 MW with one hour duration, so 1 MWh, with 10-year life, AC-AC round trip efficiency 0.85, capital cost $600/kWh, fixed O&M cost $10/kW-yr) as an investment option for capacity expansion, and the model identifies optimal amounts, zonal locations, and timing. The difference in overall electricity costs, air pollution emissions, and other metrics between the base case and the ES case measures the net benefits of ES.

This study finds substantial benefits from deploying 1,766 MW of ES at an estimated cost of \$970 – 1,350 million. At the bulk power level, these benefits include reduced energy costs (\$275 million), reduced peak capacity (\$1,098 million), ancillary services cost reduction (\$200 million), wholesale market cost reduction (\$197 million), T&D cost reduction (\$305 million), and integrating distributed renewable generation cost reduction (\$219 million), for system benefits totaling \$2,209 million.

The study goes on to document additional benefits that accrue to ES investors in the form of revenue, totaling \$1,100 million, for total system-level and investor benefits of \$3,300 million. For several use cases, the study uses the EPRI Energy Storage Valuation Tool to document that the BCR exceeds 1.00 for society as a whole: utility-owned ES at substations (3.36 BCR), municipal light plant asset (4.60 BCR), competitive electricity supplier portfolio optimization (2.05 BCR), merchant frequency regulation (3.00 BCR), merchant storage and solar (3.66 BCR), merchant standalone storage (4.40 BCR), microgrid resiliency (2.77 BCR), behind-the-meter commercial and industrial (C&I) storage and solar (1.78 BCR), and residential storage dispatched by the grid (2.43 BCR). Only straight behind-the-meter residential storage fails the net benefit test (0.49 BCR).

The choice to include both investor revenue and net system benefits as benefits is not accepted by all states because some view the investor revenue as a transfer rather than a benefit.[21] However, it has been accepted in Massachusetts. The study notes that in spite of the positive societal BCRs, very little ES has been installed, so investors must not be seeing convincing net benefits. For example, for utility-owned ES at substations, the utility currently only receives monetary benefits for distribution investment deferral and voltage support. Benefits of reduced energy costs, peak, wholesale market costs, ancillary services costs, and increased renewables integration are not captured by the utility, hence there has been little investment in ES. This could be partially remedied if rules allowing participation in ISO-NE ancillary services, forward-capacity, and other markets are clarified for ES assets, as the Federal Energy Regulatory Commission (FERC) is now encouraging.

Other use cases studied show similar revenue gaps. Some can be remedied with rule changes or clarifications to allow participation in ISO-NE markets; others require incentives such as tax credits or direct payments. Or they can wait until ES costs drop enough to match the investor's benefit streams.

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[21] Cost-benefit analysis textbooks counsel analysts to be careful not to count transfers from one party in society to another as benefits. One common problem they highlight is when there is a difference between price and marginal cost, as there is in electricity markets. This difference should be treated as a transfer between buyers and sellers of electricity, and not a social benefit, otherwise double counting occurs. (See, for example, Edward Gramlich, *A Guide to Benefit-Cost Analysis*, 2nd ed., Waveland Press, Prospect Heights, IL, 1990, pg. 63; and E.J. Mishan, *Cost-Benefit Analysis*, 3rd ed., George Allen & Unwin, Boston, MA, 1984, pp. 74-82). They also observe that the avoided "cost to the society should be valued using the opportunity cost of production, that is, the price of inputs used to produce forgone outputs," hence they should not also count revenues received from customers by utilities (Thomas V., Chindarkar N. 2019. "The Picture from Cost-Benefit Analysis." In: *Economic Evaluation of Sustainable Development*. Palgrave Macmillan, Singapore, pp. 73-74). Finally, they recommend using long-run marginal costs not short-run marginal costs for such calculations (F.A. Felder. 2011. "Examining electricity price suppression due to renewable resources and other grid investments." *Electricity Journal* 24(4): 34-46; doi:/10.1016/j.tej.2011.04.001). In short, the societal CBA should either use electricity costs paid by customers or a system-wide avoided cost number.

Finally, the Massachusetts study includes estimates of economic benefits (e.g., jobs, income) associated with ES deployments. It uses IMPLAN, a well-known Input-Output analysis tool that estimates detailed sectoral impacts due to increased expenditures of a particular type (here, energy storage). Reported impacts include an increase in Gross State Product (value added) of $6.9 million/year and 700 jobs/year persisting over a 10-year period. However, this method does not net out loss of value added and job losses associated with the displacement of conventional electric power production (such as gas turbine installation and operation), hence it substantially overstates the net economic benefits to Massachusetts.

Massachusetts Critique by Clean Energy Group

Todd Olinsky-Paul. 2019. *Energy Storage: The New Efficiency*. Report on Massachusetts' energy storage policy development prepared by the Clean Energy Group. The New England states have developed procedures for assessing the cost-effectiveness of energy efficiency programs, summarized in a regularly updated *Avoided Energy Supply Components in New England* (AESC) report.[22] This report includes many items not included in New Jersey's equivalent document.[23] The *AESC* report supports quantification of avoided capacity costs, avoided energy costs, avoided cost of compliance with renewable portfolio standards and related clean energy policies, non-embedded environmental costs, avoided T&D costs, value of improved reliability, and demand reduction induced price effects (DRIPE).

Methods for calculating DRIPE and avoided costs of compliance are still under debate, so that there are "DRIPE states" (CT, DE, MA, MD, RI, VT) and "non-DRIPE states" (ME, MI, NH, NJ, NY, OH, OR, PA, TX).[24] The Massachusetts Department of Public Utilities (MADPU) recently applied the *AESC* methodology to the question of ES in the context of its most recent *Energy Efficiency Three-Year Plans Orders and Guidelines*.[25] MADPU program administrators found that many, but not all, applications of ES passed their benefit-cost test, as discussed above and according to documentation provided in the Clean Energy Group's (CEG) 2019 report. The CEG report goes on to provide its own detailed benefit-cost analysis of ES and a critique of the MADPU findings.

A key analytical assumption incorporated into the CEG's Massachusetts analysis is that peak hours are defined as the top 10% of hours rather than the conventional and official definition that is based on time windows (peak periods in Massachusetts are officially defined as 9 am – 11 pm weekdays, excluding holidays, representing 44% of the hours in the year). By optimizing ES to shift loads away from only the top 10% of demand hours, the energy price difference between peak and off-peak hours increases dramatically (by roughly a factor of 2),

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[22] Synapse, Inc. 2018. *Avoided Energy Supply Components in New England: 2018 Report (October Re-Release*. https://www.synapse-energy.com/project/avoided-energy-supply-costs-new-england).

[23] Rutgers University Center for Green Building, "Energy Efficiency Cost Benefit Analysis Avoided Cost Assumption: Technical Memo," January 29, 2019, Update.

[24] ComEd. 2015. *DRIPE—Around the Country*. (Presentation. http://ilsagfiles.org/SAG_files/Subcommittees/IPA-TRC_Subcommittee/2-17-2015_Meeting/DRIPE_Around_the_Country_2-16-15.pdf). See also State and Local Energy Efficiency Action Network. 2015. *State Approaches to Demand Reduction Induced Price Effects: Examining How Energy Efficiency Can Lower Prices for All*. (Prepared by Colin Taylor, Bruce Hedman, and Amelie Goldberg from the Institute for Industrial Productivity under contract to Oak Ridge National Laboratory).

[25] Massachusetts Department of Public Utilities. 2019. 2019-2021 Three Year Plans Order (D.P.U. 18-110 through D.P.U. 18-119, January 29, 2019. https://www.mass.gov/guides/energy-efficiency-three-year-plans-orders-and-guidelines).

assuming that the user experiences time-varying electricity costs. The CEG report states that "this fundamental definition of peak hours provides the basis for the positive BCR [Benefit/Cost Ratio] for battery storage."[26]

The MADPU analysis discounts DRIPE by 90%, whereas the CEG analysis does not. Additionally, the CEG report recommends that Massachusetts quantify several additional benefits of ES and offers suggested values:

1. Avoided power outages
    a. Energy system reliability benefit (the system-wide benefit of fewer grid outages)
    b. Non-energy reliability benefit to consumers (customer's value of back-up power)
2. Higher property values (after storage is installed)
3. Avoided fines to utilities for outages
4. Avoided cost to utilities of collections and terminations
5. Avoided cost to utilities of emergency calls during outages
6. Job creation
7. Reduced land use due to peaker replacement (using distributed storage as a peaking resource to avoid investments in new fossil fueled peaker plants, which require more land)

Some of these benefits or their estimation methods are debated in the literature and trade press and have not been accepted as valid by public utility commissions (including MADPU, according to the report). Energy system reliability benefits at the grid level, and non-energy reliability benefits to customers need to carefully avoid double counting of benefits. Higher property values, avoided fines, and costs of collections and terminations have been hard to attribute to ES given their small effect and the many other factors that influence their valuation. Job creation should be done on a net and not gross basis, as discussed previously. Reduced land use claims should take a full value chain perspective and acknowledge upstream land consumption which may be located out of state, as well as the reversibility of the land use, and local market conditions.[27]

Compared to both the *AESC*-based official analysis and the CEG's even more aggressive analysis for Massachusetts, the New Jersey analysis includes a much shorter list of quantified benefits, reflecting both the lack of policy consensus in New Jersey regarding benefits such as DRIPE and this research team's skepticism about the validity of measuring benefits such as reduced land use. Technology cost trajectories are not dramatically different. The overall result is that benefit-cost ratios are generally lower in the New Jersey analysis, although the rank ordering of preferred applications is similar.

[26] Clean Energy Group. 2019. *Energy Storage: The New Efficiency*, pg. 18.

[27] Clinton J. Andrews, Lisa Dewey-Mattia, Judd Schechtman, and Mathias Mayr. 2011. "Alternative energy sources and land use." in G. Ingram & H. Hong, eds., *Climate Change, Energy Use, and Land Policies*. (Cambridge, MA: Lincoln Institute of Land Policy, 2011).

Comparison of studies

The New York and Massachusetts studies were completed before the current New Jersey study. They provide valuable evidence that ES brings net benefits to society from the top-down perspective of optimizing the regional electric power system. They identify a range of use cases that add value in varying amounts to the bulk power system. They also explore reasons why market forces have not produced much ES investment, and a key message is that investors are not receiving benefits to offset their costs. They propose policies to encourage greater investment at the bulk power level, distribution level, and on the customer side of the meter.

The New Jersey study takes these lessons as its starting point and places emphasis instead on a series of bottom-up ES applications that have been less well studied. This acknowledges the New Jersey context as a medium-sized state within the very large PJM electrical region, which has already created a thriving, if highly specialized, ES market for FR and other ancillary services. In contrast, New York has its own NYISO whose borders are contiguous with those of the State, and Massachusetts is the dominant player in ISO-NE, so their studies need to prioritize the bulk power perspective.

To help readers compare the points of convergence and difference across studies, Table 6 summarizes their key methodological choices and assumptions.

Table 6 Comparison of Key Assumptions in NJ, NY and MA Energy Storage Analyses

	New Jersey	New York	Massachusetts	CEG MA Critique
Framework	Benefit-Cost Analysis	Benefit-effectiveness Analysis (Breakeven Installed Cost)	Benefit-Cost Analysis	Benefit-Cost Analysis
Time Frame	10 years	10 years	10 years	10 years
Bulk Power Capacity Expansion Optimization (for generation within transmission constraints)	No (NJ a part of PJM region), re-uses RGGI scenarios to estimate high-renewables future, adds Offshore Wind case	Yes (NY = NYISO)	Yes (optimization for MA, as part of ISO-NE region)	No (re-uses MA scenarios)
Distribution-level Optimization	Yes for illustrative cases	Yes for illustrative cases	Yes for illustrative cases	No (re-uses MA analysis)
Specific customer-side use cases/applications	Yes, includes detailed applications to multiple C&I and residential customer profiles	Yes, includes applications to several generic C&I and residential customer profiles	Includes a few generic C&I and residential customer types	Includes the generic C&I and residential customer types from the MA study
Benefits quantified	Revenues received by investor (which by assumption capture ancillary services, capacity value, distribution savings, reduced fixed O&M costs, and generation cost savings), avoided air pollutant emissions, resiliency/ reliability	Ancillary services, capacity value, distribution savings, reduced fixed operations and maintenance costs, generation cost savings, avoided CO2 emissions	System-level: reduced energy costs, reduced peak capacity, ancillary services cost reduction, wholesale market cost reduction, T&D cost reduction, and integrating distributed renewable generation cost reduction Investor: revenue received	System-level: reduced energy costs, reduced peak capacity, ancillary services cost reduction, wholesale market cost reduction, T&D cost reduction, and integrating distributed renewable generation cost reduction

				Investor: revenue received Additional: avoided power outages, increased property values, avoided fines, avoided collection & termination charges, avoided emergency calls, job creation, and land consumption
Cost in 2020 for Li-Ion, 4-hour, \$/kWh (\$/kW)	\$324-\$660 (\$1,295-\$2,640)	\$356 (\$1,426)	\$400-\$1000 (\$285)	N/A
Cost in 2020 for Li-Ion, 1-hour, \$/kWh (\$/kW)	\$512-\$1192	\$810 (\$771)	\$400-\$1000 (\$315)	\$299-\$477 (\$1036-\$1,568)

Clean Energy Act (CEA) Elements

This section of the report discusses the Rutgers team's detailed findings, organized according to the legislative questions identified as elements of the Clean Energy Act (CEA).

Element 1

Consider how the implementation of renewable electric energy storage systems may benefit ratepayers by providing emergency back-up power for essential services, offsetting peak loads, and stabilizing the electric distribution system.

Summary of Findings

The benefits posed below do not take into account cost of ES. Cost and benefit discussion of ES are part of Elements 4 and 6.

- Energy storage improves resilience; however, the impact and the sizing of ES capacity depends on several factors including technology combinations (e.g., with PV or emergency back-up generators), facility load profile and critical load requirements. Without PV or DG installation, ES must be sized at 50% or more of the facility's peak load to serve typical critical load (~ 70% or higher for most critical facilities) for short durations (within four hours). Smaller ES capacity with shorter discharge durations (~ an hour) can be used to serve vital loads (~ 20% to 30%) of facilities during outages.
- In the presence of PV, and assuming that it is appropriately sized to meet 80% or more of the peak load, small ES sizes (i.e., within 25% of peak load) suffice, and increases in ES capacity have diminishing returns. In the presence of existing emergency back-up generators, ES does not show noticeable added value.
- For the twenty-four case studies that we have investigated, ES paired with renewables or DG can serve all critical loads almost 100% of the time during power outages of short duration (i.e., up to three or four hours). We note that local generation is used in these cases to charge storage (i.e., if needed) and also power the facility; so not all credits go to ES, and we must prorate the value of ES resiliency for such conditions.
- Increase in ES capacity in the presence of PV can generate significant value in terms of mitigating the loss of facility loads when outage durations are in days. Otherwise, ES alone fails to be a viable solution to mitigate facility resilience under potentially prolonged outages.
- Energy storage generates more value in demand charge saving compared to TOU energy cost saving, and the economic benefits of peak load reductions are the most profound in EDC territories with the highest demand charges ($/kW). In our twenty-four scenario analysis, peak demand reduction only due to ES is between 40% and 50% while energy consumption reduction (reduction in purchase from the grid in case of no net metering) only by ES is less than 15% for PV/ES systems.

- Energy storage has the potential to transform how EDCs plan and operate their electric distribution systems, and with the extensive deployment of ES across the State of New Jersey, EDCs may revisit their demand charging schemes.
- Resilience stacked with Energy Bill Management (EBM) can significantly increase the overall value of ES for facilities and distribution networks. However, the caveat is that aggregating the two together and using the aggregate measure for decision making involves translating risks of unserved critical loads to dollar values. We note that in both applications the marginal value of an increase in ES duration diminishes but we are not sure how fast it happens from one to another.
- Our recommendation is that New Jersey assigns weighting factors to resiliency and EBM for prioritization and further economic analysis. These weights can incorporate stochastic drivers for resiliency; for instance, in areas which are highly subject to natural disasters or in parts of the distribution network with statistically significant outages and circuit failures, resiliency carries a much higher weight factor than EBM.
- As a further issue with resilience value, we might expect that for extended outages, ES might enable serviceable, powered, emergency gathering spaces, where the societal value might be substantially higher than the financial calculation of the reduction in unserved load, as modeled above. Installations such as the solar+storage installation at Hopewell Valley High School, for example, provide a gathering place with abundant value to the nearby community facing an extended outage. Putting a direct dollar value on these rare and unpredictable emergency resilience usages is a difficult proposition and beyond the scope of the ESA report.
- Combined ES/PV or standalone ES systems can mitigate power outage risks, help reduce peak loads, and serve the network at distribution level. These impacts are dependent on the configuration of ES installation across the network (i.e., centralized or decentralized).
- Increase in roundtrip efficiency of ES improves its value impact for use cases considered in this report. However, depending on application, these improvements may be considered marginal. It is recommended that the value improvements of ES as a result of increase in the roundtrip efficiency be weighed against cost increases prior to implementation.

Analysis and Discussion for Lithium-ion (Li-ion) Batteries

ES has many potential applications. The following discussion covers the key applications for this set of technologies and the basic criteria for judging whether deployment might have value. Cost and benefit analysis of these applications will be presented in Elements 4 and 6. Other storage technologies will be discussed in a separate section.

Resilience and Emergency Back-up Power

Energy storage can be deployed at critical customer-sites (i.e., facilities) to mitigate risks of unserved critical loads during power outages. A common belief supported by stakeholders' comments[28] is that ES can replace, or serve as a supplement to, traditional back-up generators (e.g., diesel, natural gas), and have the added benefits of zero on-site GHG emissions with virtually instant dispatch.

For facilities with no on-site power generation, the mitigated risk depends on the shape and variability of the facility's load profile (i.e., measured by load factor) and percentage of critical loads. The duration of outage plays a vital role in such risks. Our analysis uses published power outage statistics published by the EIA, including the time of event and duration of the outage for the State of New Jersey.

The assumption here is that storage is fully charged and available for emergency purposes when needed. In real life situations, however, fully charged ES might not be available, especially if several applications are stacked together. Some stakeholders have also noted concerns about stacking up emergency use of ES with other applications, highlighting the need for proper control strategies to ensure that resiliency receives a high enough priority. A suitable battery management system protocol can be established to always maintain a percentage of storage available for resiliency applications. To better understand the relationship between resilience and ES capacity and in the absence of proper economic data, we used risk mitigation (quantified by avoided loss of load) as a measure of value generated by ES capacity.

Resilience for short duration outages

According to our findings based on the analysis of 24 facilities (see Figure 2), ES alone with discharge durations of 4 hours with capacity set at 25% or more of the peak load is sufficient to avoid at least 50% of loss of load for outages that last a few hours (see Figure 14). According to Figure 14, an oversized ES system can completely mitigate loss of load risk.

Some stakeholders' comments also echo this,[29] stating that, as energy-finite resources, ES systems cannot be relied upon solely to provide back-up power for extended periods. From stakeholders' comments and our experiments, ranges of up to four hours of discharge duration work. For the same range of outages, the marginal value of an increase in discharge duration

[28] Stakeholder participants. 2019. (Comments made by SPs for CEA Element 1 at Energy Storage Stakeholder Meeting held on March 20, 2019. See Appendix B – Stakeholders' Responses, pg. 6-16).

[29] Stakeholder participants. 2019. (Comments made by stakeholder participants for CEA Element 1 at Energy Storage Stakeholder Meeting held on March 20, 2019. See Appendix B – Stakeholders' Responses, pg. 6-16).

diminishes, but the value of the increase in ES capacity can lead to a substantial increase in avoided loss of load (see Figure 15 left column). In facilities with existing PV installation, small ES capacity (less than 50% of peak load) has the potential to deliver almost a fully resilient system for short outage durations, as seen in Figure 15 (right column). In the absence of PV and for short outage durations, the level of resilience strongly depends on ES capacity.

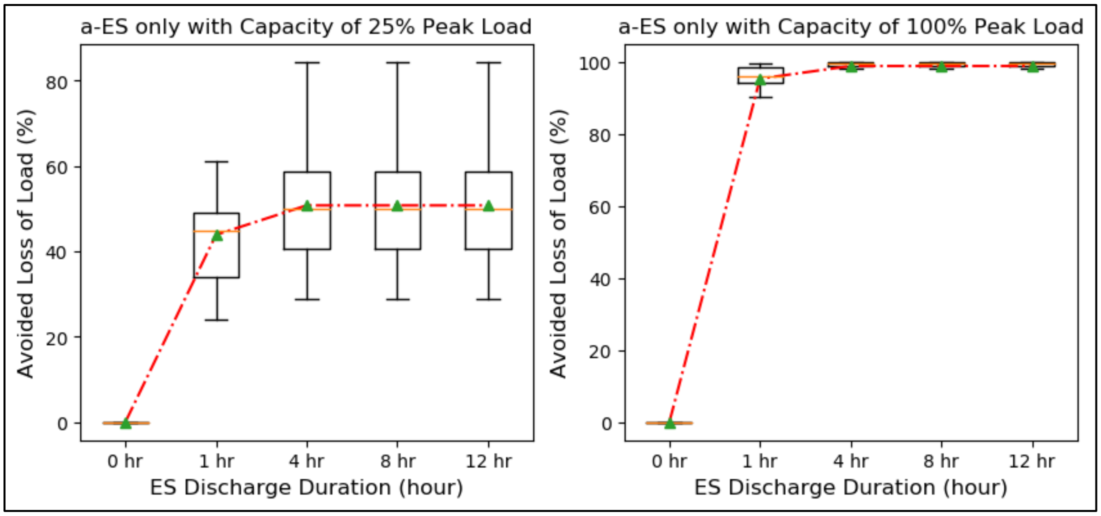

Figure 14: The impact of ES discharge duration at different capacitates on resiliency for short outage events.

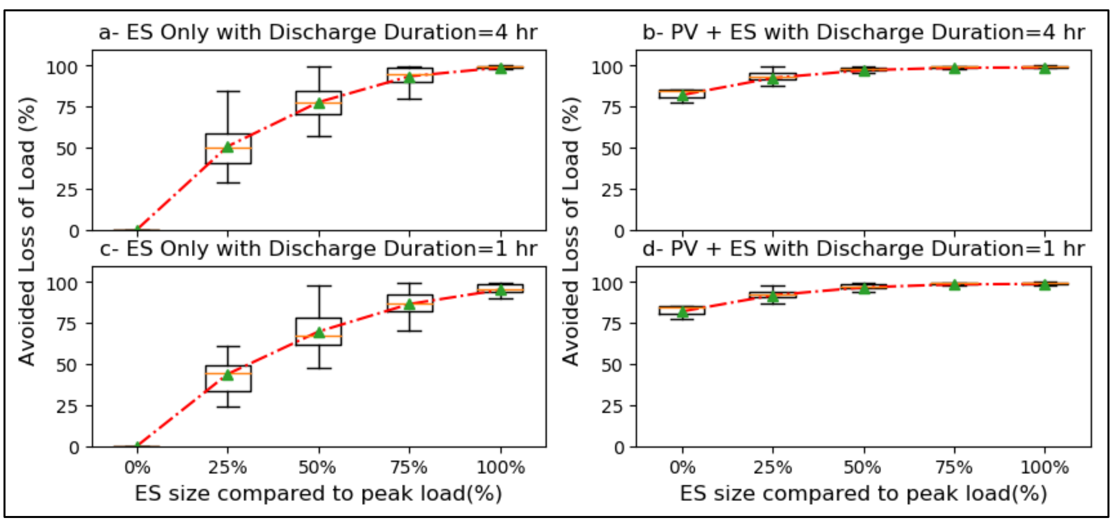

Figure 15: The impact of ES discharge duration at different capacitates on resiliency for short outage events.

Figure 16 to Figure 19 illustrate six use-cases for ES resiliency application during short outage events. Considering the fact that on average, air conditioning load constitutes 30% of the demand, we assume 70% critical load is the goal for resiliency during short outages. This number can vary based on facility operator objectives. Figure 16 and Figure 17 illustrate that ES with 1-hour duration mainly requires a high capacity size (75% of the facility's peak load) to achieve 70% of critical load whereas a 4-hour discharge duration can provide the critical load with a lower capacity. This indicates that ES sizing is crucial and case-specific to achieve a desired critical load; however, there is a tradeoff between the benefits and economics here that has to be taken into account. Overall, optimal sizing of ES and integration of ES with customer site renewables are driving factors to deliver resilience.

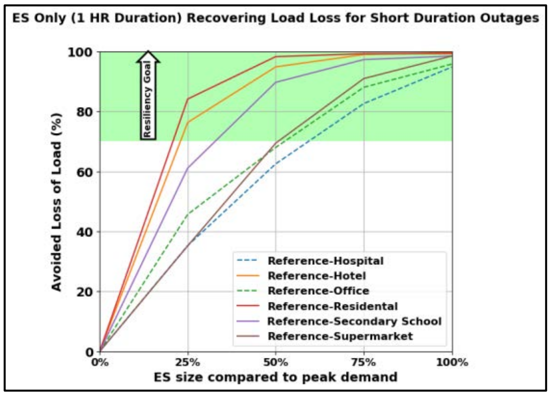

Figure 16: ES-only (1-hour discharge duration) impact on achieving critical load of 70% for 6 different facilities.

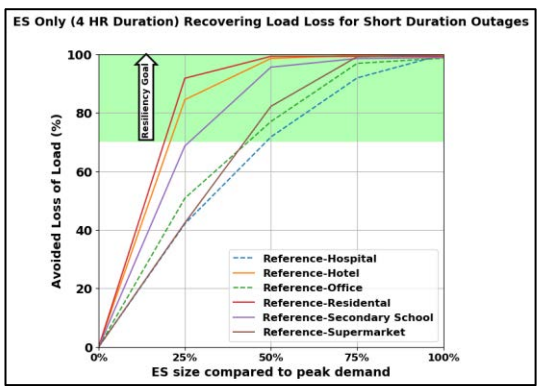

Figure 17: ES-only (4-hour discharge duration) impact on achieving critical load of 70% for 6 different facilities.

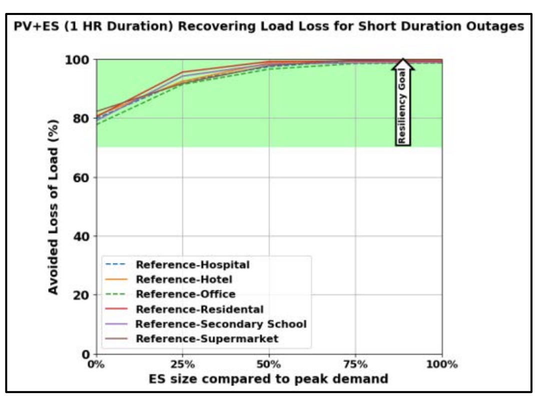

Figure 18: PV with ES (1-hour discharge duration) impact on achieving critical load of 70% for 6 different facilities.

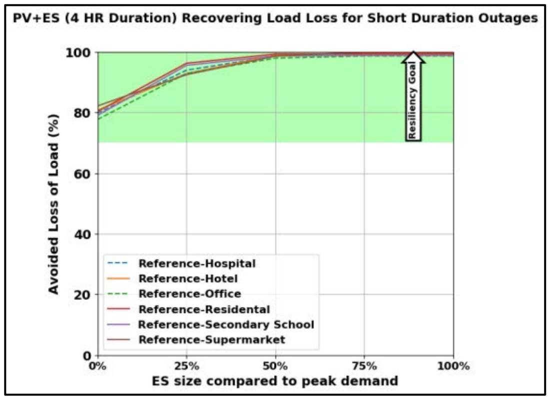

Figure 19: PV with ES (4-hour discharge duration) impact on achieving critical load of 70% for 6 different facilities.

Long duration resiliency

For outage durations of several days, standalone ES does not produce any viable solution to mitigate load loss, but in the presence of other on-site technologies, ES adds value. For a long duration of power outage, the pairing of storage with renewables or back-up generators could benefit the facility in several ways: i) ES can be used to power the facility until DG is up and running, and ii) Renewables can be used to recharge storage (subject to availability of PV or wind power at the location) during an outage.

The facility's resiliency when equipped with PV/ES, highly depends on ES discharge duration and capacity.

Figure 20 illustrates that increasing ES discharge duration from 1-hour to 4-hour has a noticeable impact; the improvement in avoided load loss dramatically diminishes for above 4-hour discharge durations. On the other hand, high ES capacity (in kW) can effectively mitigate the risk and uncertainty of load loss compared to small ES capacities (compare the two graphs in Figure 20).

According to Figure 21, when PV is combined with ES and if solar radiation is available, outage duration does not impact facility's resiliency; however, with unreliable incident solar radiation, the risk increases and becomes dependent on weather condition. Increasing the ES capacity to 100% of the facility's peak load increases the avoided lost load by over 10% for all outage scenarios, with better results for four and seven days. Our explanation for this phenomenon is that the potential loss of load increases with the number of outage days, but at the same time, the chance of having more days with PV charging also increase.

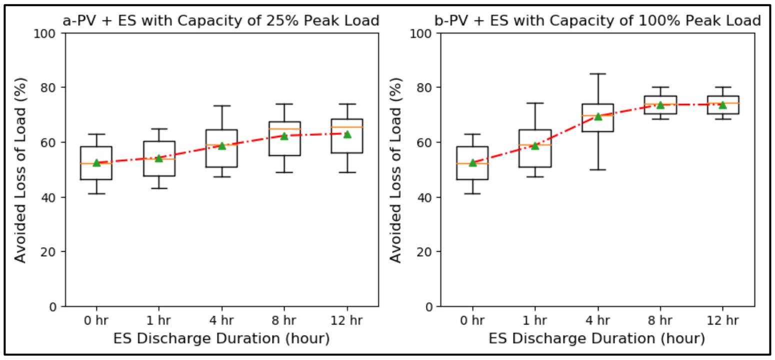

Figure 20: Impact of ES discharge duration and capacity avoided load loss risk for a 7-day outage scenario.

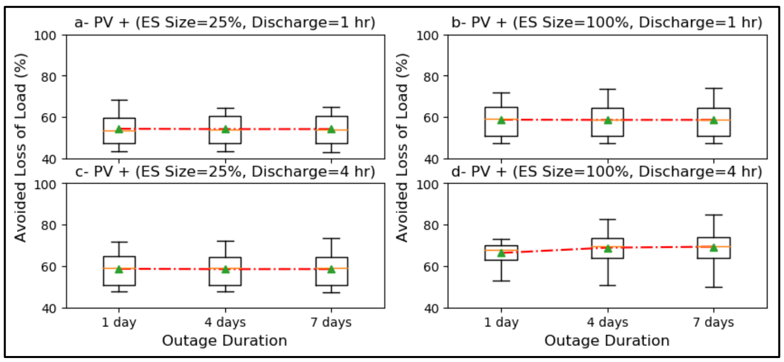

Figure 21: Combined EV/PV value generation for long duration outages (1 day to 7 days).

The above findings are sensitive to load profile shape. Figure 22 and Figure 23 depict the facility resiliency for six different buildings with different ES sizes. As seen in Figure 22, most facilities can supply 50% of the demand with an ES sized at 50% of the facility's peak load. It is also shown in Figure 22 that 70% avoided load loss can be achieved by higher ES capacities whereas 1-hour duration ES systems cannot support PV generation to achieve 50% or 70% avoided load loss even for large ES sizes.

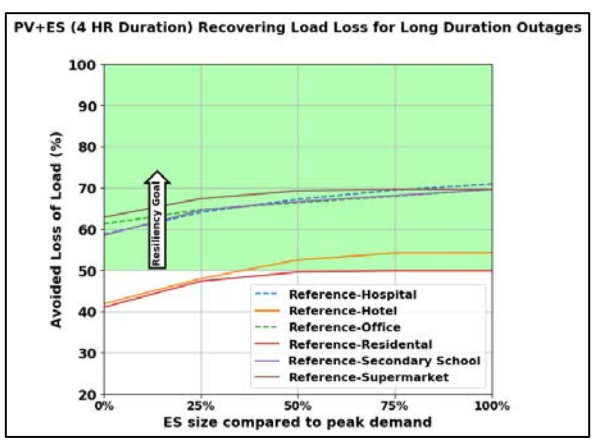

Figure 22: Four-hour duration batteries support some facilities achieve even 70% critical load by an ES size of 50% of the peak load.

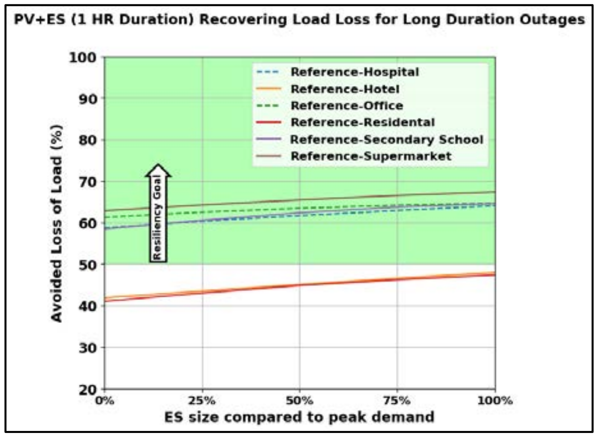

Figure 23: One-hour duration cannot help the facility achieve 70% although it reaches more than 60% for most facilities.

Offsetting Peak Loads and Reducing Energy Costs

At the customer-site level, resiliency can be stacked up with EBM applications to increase the value generated by ES. Realizing EBM savings and generating cash flow, requires pairing with renewables or managing charge and discharge of storage that takes into account dynamic pricing (i.e., if available). One of the stakeholders reaffirmed this application of EBM with the following quote: "*For example, customers on demand rates with behind-the-meter storage assets can manage their peak usage thereby lowering their energy costs by managing their demand charges*."[30] Electric Bill Management includes two main applications, namely TOU energy cost saving, and demand charge saving.

We study use cases with two different configurations: ES supporting PV generation and stand-alone ES system. For all use-cases, the assumption is that the facility does not have net metering. Increased ES capacity and discharging durations lead to more peak demand reduction, but the impact of discharge duration becomes less effective after a certain threshold (Figure 24). Furthermore, ES generates more value in demand charge saving compared to TOU energy cost saving especially when integrated with onsite PV generation (Figure 25).

Figure 26 and Figure 27 illustrate the impact of ES size on peak load reduction while supporting PV generation. As seen in these figures, ES capacity increase always leads to improvement in peak load reduction and recovering PV generation; however, the trade-off between facility operation objectives and the economics cannot be neglected.

[30] Rockland Electric Utility Company (RECO). 2019. (Comment made by stakeholder RECO for CEA Element 1 at Energy Storage Stakeholder Meeting held on March 20, 2019. See Appendix B – Stakeholders' Responses p. 11).

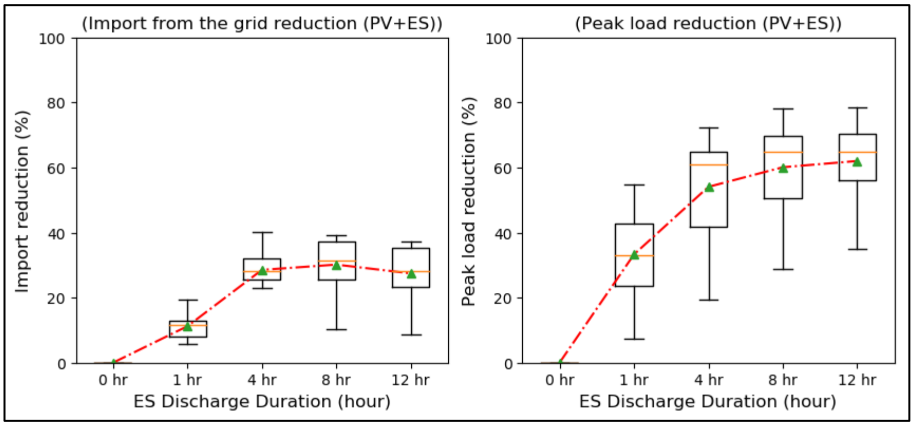

Figure 24: ES supporting PV for reduction in power import and peak shaving (no net metering) for different discharge durations.

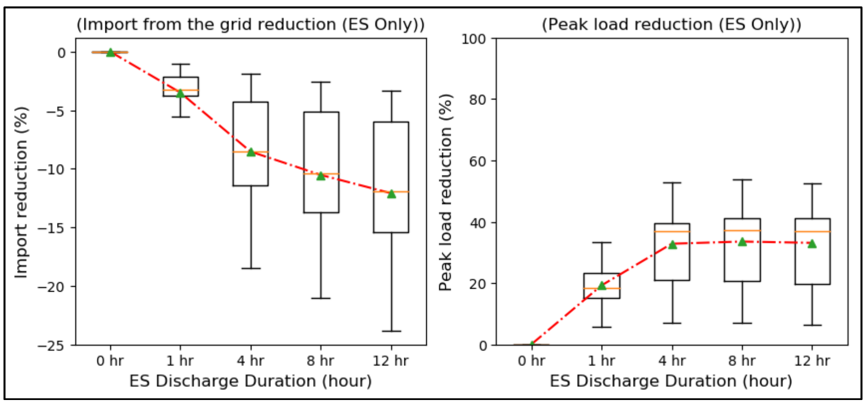

Figure 25: ES application in facility peak shaving (no net metering) for different discharge durations.

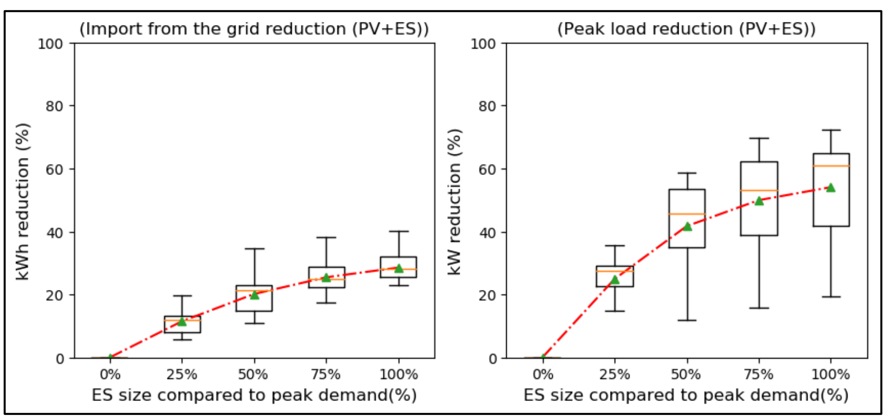

Figure 26: ES supporting PV for reduction in power import and peak shaving when net metering is not allowed.

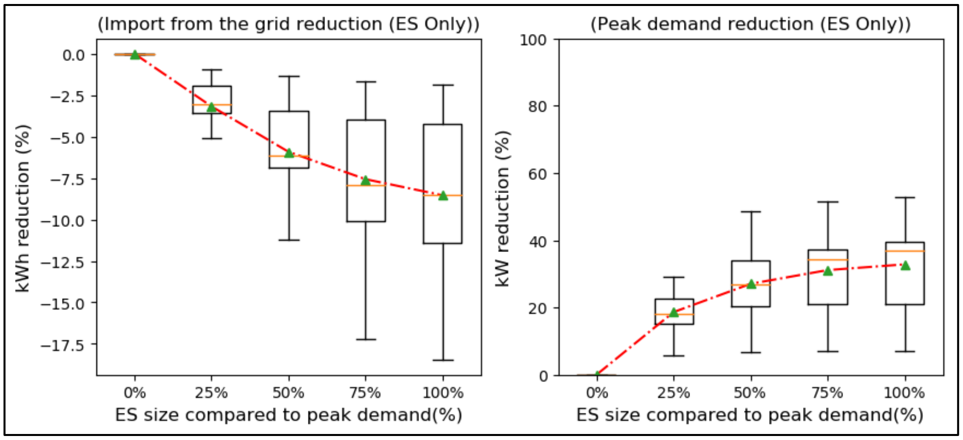

Figure 27: ES application in facility peak shaving when net metering is not applicable for different ES rated capacities.

The economic benefits of peak load reductions are the most profound in EDC territories with the highest demand charges ($/kW). With the demand charge as a prevailing factor in EBM savings, the geographical area under the EDC with the highest tariff can be a sweet spot regarding cost and benefit factors. As indicated by one of the stakeholders,[31] ES has the potential to transform how EDCs plan and operate their electric distribution systems. With the extensive deployment of ES across the state, EDCs may revisit their demand charging schemes.

Energy storage installed at or near a customer site can also reduce the nodal peak demand significantly if coupled with renewable generation. According to stakeholders' comments,[32] two to four hours of storage duration is reasonable for peak load offsetting. Some other stakeholders emphasized that both behind-the-meter and in front of the meter installation of ES can reduce peak usage by dispatching ES during high system load conditions and can provide system-wide and societal benefits by reducing overall capacity obligations.

The value of energy cost savings extends beyond a single customer-site to multiple sites with geographical proximity or a community. Quoting one of the stakeholders: "*Solar PV coupled with energy storage can be even more beneficial because energy storage can be deployed to reduce demand charges for commercial electric ratepayers. In most cases, affordable multifamily housing facilities fall into this customer class. Deploying solar and storage for affordable multifamily buildings can offset a large portion of energy costs. The savings can be used to reinvest in a building, or to invest in more affordable housing*." [33] Rutgers findings confirm these comments.

[31] Rockland Electric Utility Company (RECO). 2019. (Comment made by stakeholder RECO for CEA Element 1 at Energy Storage Stakeholder Meeting held on March 20, 2019. See Appendix B – Stakeholder Comments p. 9).
[32] Stakeholder participants. 2019. (Comments made by stakeholder participants for CEA Element 1 at Energy Storage Stakeholder Meeting held on March 20, 2019. See Appendix B – Stakeholder Comments pp. 2-11).
[33] VES. 2019. (Comment made by stakeholder participant VES for CEA Element 1 at Energy Storage Stakeholder Meeting held on March 20, 2019. See Appendix B – Stakeholder Comments p. 4).

Stabilizing the Grid

Energy storage has the capability of responding to FR signals in milliseconds. Frequency regulation is a "power storage" application of ES.[34] The overall consensus among stakeholders[35] and our own preliminary analysis show that under current incentive structures, ES can generate significant value in the FR market. However, as commented by a number of stakeholders, the relatively small size of the FR market (i.e., 1% of the annual cost of the PJM capacity market), and the very high compensation rates of FR market participation for a period of time, suggest that the FR market will prove to be unreliable as a sustainable core revenue stream for ongoing ES project development. Also, in FR analysis, other factors such as uncertainties arising from bidding processes should also be taken into account. Furthermore, the distribution market poses challenges that are different than the traditional PJM FR market or transmission market, as indicated by one of the stakeholder's comments.[36]

The PJM Interconnection has active markets for ancillary services, and ES devices already participate in those markets, especially to provide FR services. PJM-wide, behind-the-meter batteries have increased their provision of FR services from 20,000 MWh in 2014 to 72,000 MWh in 2018, with growth continuing.[37] This ES application remains healthy in part because the FERC regularly revisits the rules under which PJM operates this market, most recently on January 19, 2019.[38]

Energy storage can contribute and improve voltage stability of a power distribution network. As noted by some stakeholders, storage technology can respond very quickly to changes in voltage, resulting in a more stable, reliable distribution grid. Indeed, appropriately managed storage technology can play a role in regulating the voltage on the EDCs' distribution systems as DERs deploy and inject electricity onto the grid. Some examples that we have examined so far confirm the validity of voltage stability brought by an ES infusion to model distribution networks. This report examines more cases and attempts to find conditions that limit such benefits.

A further issue with the FR market is its possible connection to the highly variable solar and wind renewables generation. At a qualitative level, we might expect that the up and down ramping of solar and wind with cloud motions or wind gusts might increase the need for FR assets on the grid, an issue that might require greater attention over time with the addition of OSW and increasing residential solar generation. Even the expanding ownership of EV's might inject similar variability when users decide to charge -- adding large residential power loads to

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[34] Stakeholder participant. 2019. (Comments made by stakeholder participant for CEA Element 1 at Energy Storage Stakeholder Meeting held on March 20, 2019. See Appendix B – Stakeholders' Responses pp. 6-16).

[35] Note that the base case in (W PV) scenarios is the solo PV systems, so the revenues reflect the impact of adding ES to the PV system. Some combined effects still remain and are hard to separate.

[36] Comment made by New Jersey Resources (NJR). 2019. (Comment made by NJR for CEA Element 1 at Energy Storage Stakeholder Meeting held on March 20, 2019. See Appendix B – Stakeholders' Responses).

[37] PJM. 2019. *2018 Distributed Energy Resources (DER) in PJM Demand Response Markets*. (Report prepared by PJM Demand Side Response Operations, January 2019, pg. 9).

[38] FERC Order Accepting PJM Tariff Revisions. 2019. (Docket ER19-383-000, Issued January 18, 2019. https://www.ferc.gov/CalendarFiles/20190118162546-ER19-383-000.pdf).

the grid at uncertain times. Comparison of literature reports of FR revenue within the PJM network over time suggest that solar has *not* added to grid power instability. For example, Byrne et al[39] examined flywheel storage and arrived at an annualized FR revenue of about $320K per MW (for regulation signal data applicable to the 6/2014 through 5/2015 time period). A more recent publication (Xu et al[40]) examines battery storage using data from 3/2016 to 2/2017, finding annualized FR revenue of about $147 K per MW, quite a bit smaller than the revenue from 2014/15. During this same time period there has been a growing expansion of solar added to the New Jersey grid, yet the FR revenue has dropped significantly. This downward trend in FR value has partly come from a variety of other demand response facilities that can bid into this market, thus driving the FR value downward. Given the overlap between the growth of PV and EV and the simultaneous growth of facilities offering FR services it is unlikely that the future growth of solar or wind in New Jersey will have uniquely negative consequences for grid stability or drive a need for battery storage to supply FR services.

For ES arbitrage applications, the simulation results based on 2017 and 2018 PJM data indicates that ES discharge duration does not add noticeable value to revenues but ES size highly impacts the revenues. As seen in

Figure 28, possible arbitrage revenues by ES has been improved from 2017 to 2018 (increase in revenues by 12.7% (for small ES sizes) to 20.35% (large ES sizes)).

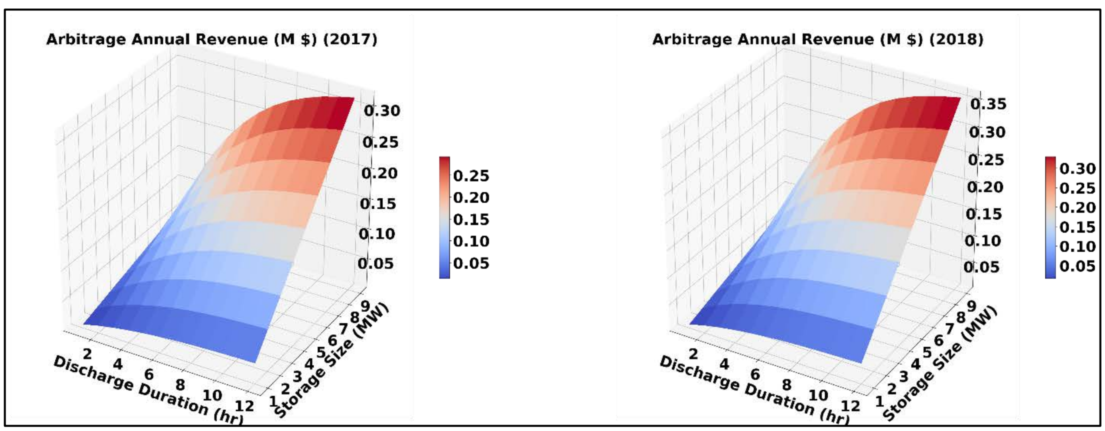

Figure 28: Arbitrage revenues for different ES capacities and durations based on NJ average LMP for 2017 and 2018.

For ES applications in the FR market, it can be seen in Figure 29 that revenues are highly dependent on ES size in MW. On the other hand, a comparison between FR revenues with respect to ES capacity in (MW) for 2017 and 2018 indicate that there is a slight increase of 11.3% in revenues.

[39] R.H. Byrne, RJ Concepcion, and CA Silva-Monroy. 2016. "Estimating Potential Revenue from Electrical Energy Storage in PJM." (2016 IEEE Power and Energy Society General Meeting.)

[40] BL Xu; Y Shi; DS Kirschen; BS Zhang. "Optimal Battery Participation in Frequency Regulation Markets."(*IEEE Transactions on Power Systems*. 2018; 33(6):6715-25).

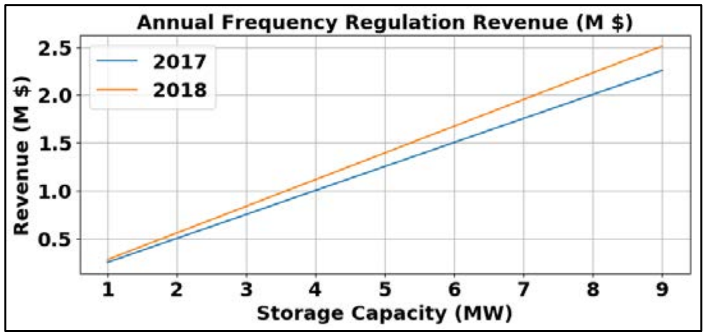

Figure 29: Frequency regulation revenues for different ES capacities based on NJ 2017 and 2018 PJM data.

Analysis and Discussion for other ES technologies

The analysis for all use-cases indicate that the round trip efficiency (attributed to different ES technologies) impact resiliency for short outages in the range of 2% to 13.0% (Figure 30) and for long duration outages in the range of 1.5% to 8% (Figure 31).

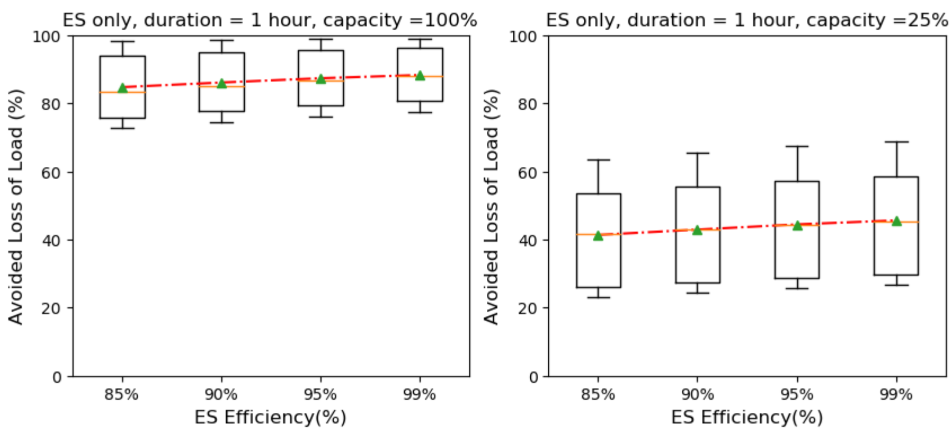

Figure 30: Round trip efficiency impact on resiliency improvement by ES-only for short-duration outage events.

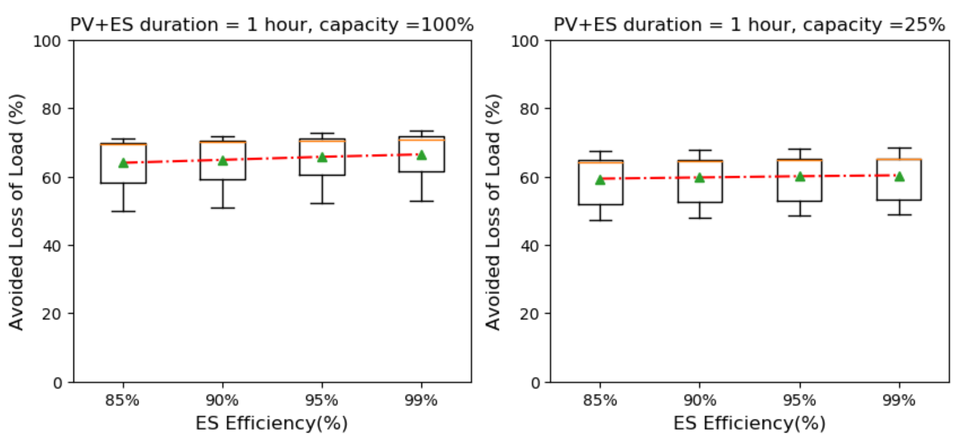

Figure 31: Round trip efficiency impact on resiliency improvement by ES-only for long-duration outage events.

In addition, ES efficiency improves power losses in 6% range and peak shaving in about 7% range for stand-alone ES systems.

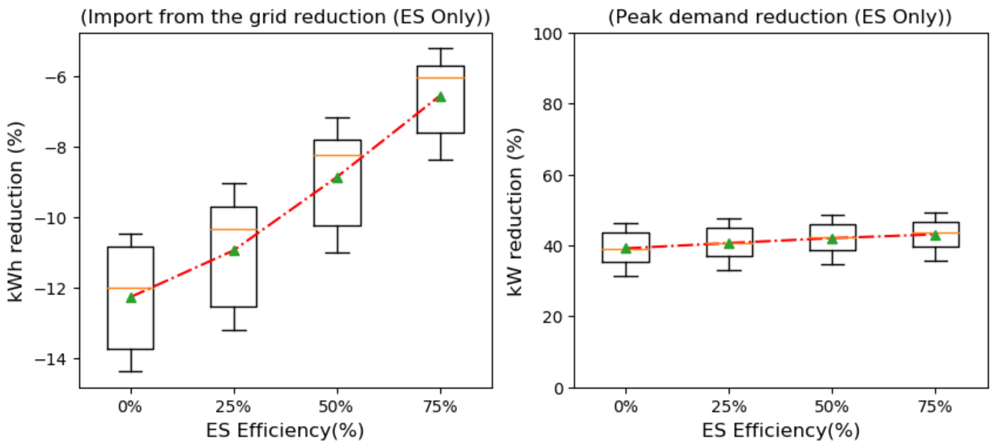

Figure 32: Round trip efficiency impact on ES-only applications for peak shaving and bill reduction.

It is recommended that the value improvements of ES as a result of increase in the roundtrip efficiency must be weighed against cost increases prior to implementation.

Element 2

Consider whether implementation of renewable electric energy storage systems would promote the use of electric vehicles in the State, and the potential impact on renewable energy production in the State.

Summary of Findings

Energy storage has an important role in encouraging EV adoption and assisting in enabling PV installation more broadly than currently allowed. ES deployed at DC fast-charging stations is demonstrated to assist with substantial reduction of demand charges – enabling more cost-effective business plans for building out infrastructure for smoother EV ownership. More visible and extensive charging infrastructure will ease consumer anxiety when considering EV ownership. The connection between ES and PV adoption has both resilience and deployment scale advantages, as described further below. The resilience benefit derives from the ability of a house or facility to go into island mode and store the daily-generated PV power for nighttime usage. Additional PV expansion can be enabled by having ES added to smooth the interaction between the time when power is generated and deliver it to the grid more gradually.

Analysis and Discussion

The following section discusses, in turn, several possible links between implementation of ES and (a) electric vehicle promotion, and (b) renewable energy production.

Electric Vehicle (EV) Promotion

Electric vehicle purchases are increasing at a rapid rate in New Jersey, based on state registration data provided by NJ BPU. The EVs registered in New Jersey grew by 37% in 2017 and 56% in 2018 to reach a level more than 8000 pure EVs at present. Electric vehicle ownership is clustered in higher-income zip codes as shown in Figure 33, and this pattern is likely to continue until the technology achieves cost parity with conventional vehicles.

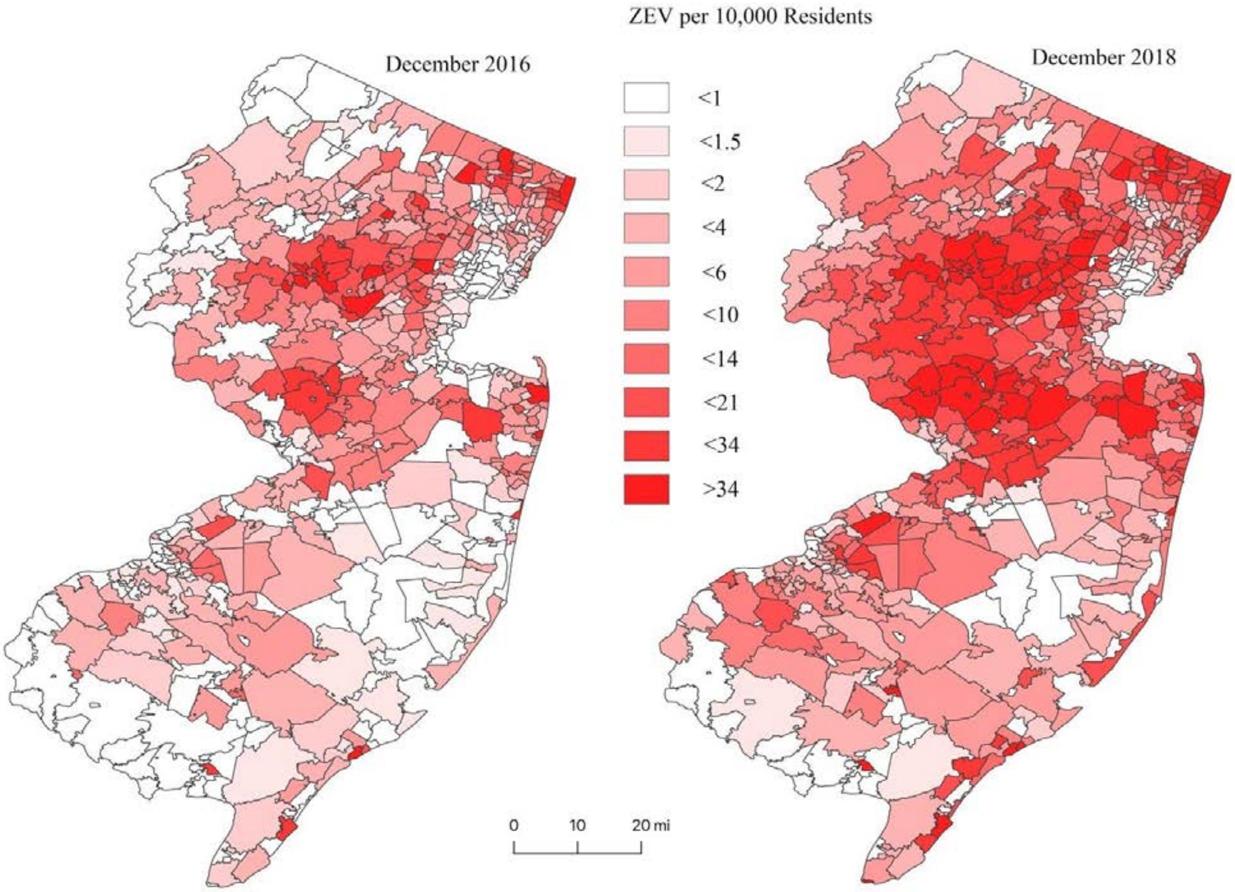

Figure 33: Zero-Emission Vehicles (pure EV only) per 10,000 residents mapped by zip-code.

Range anxiety and time to charge remain two major barriers to mass adoption of EVs even with the growing trends in the price reduction of these vehicles. The EV industry seems to be moving quickly to overcome range anxiety by providing models with larger battery capacity – and faster-charging capability. However, the issue and challenge of access to direct current fast-charging (DCFC) remain a work in progress infrastructure problem. A sizeable and visible deployment of DCFC along heavily-traveled corridors could help car buyers feel confident that a pure EV would always meet their needs and assist in growing EV adoption.

Direct current fast-charging stations, on the other hand, experience a high load for short durations, so inject variability into the grid and will incur higher demand charges (up to 80% of total electric bill) that may make it difficult for such a "fueling station" to operate profitably. In addition, the pattern of usage times scales with peak traffic hours adding load during peak grid times. Adding ES sized appropriately to these facilities could allow more gradual off-peak charging from the grid and yet supplying drivers with the fast fill-up when they require. A recent study of a commercial venture offering public pay-for-charging stations (EVgo) and their DCFC stations deployed in California[41] profiled seasonal and hourly usage patterns that are useful background for estimating the value of adding storage at DCFC stations.[42] In detail, the report noted a typical station logged monthly peak power of 45 kW and average monthly energy consumption of ~3000 kWh.

With an appropriately sized battery, it would be possible to charge the battery at a continuous low rate 24-hours a day but extract high power from the battery when EV charging is required. This smooth charging profile would lead to a reduction by more than 90% of the peak demand value – and major savings for the station operator. The storage capacity required for this typical DCFC station would be 45 kW and 100 kWh for this scenario, though recognizing that there is variability in usage patterns it might be expected that larger batteries will be needed; the growth of EV adoption will also require these numbers to rise. This is supported by a recent announcement by Electrify America that they are contracting for Tesla batteries to be used with some future DCFC charging stations.[43] They report a battery size of 210 kW and a storage capacity of 350 kWh, in line with being prepared for growing EV adoption in the future. As usage will likely grow with time, it might be expected that a DCFC filling station could add storage in a modular way to balance the need as the New Jersey population continues buying and using EVs.

While having local ES at a DCFC station can spread the power use through a full 24-hour, lower-level power usage period, it is unlikely that the EDCs could be guaranteed of that lower power usage. It is likely that code restrictions will necessitate the upgrading of power service to such charging stations -- meaning that the EDCs might still experience increasing infrastructure costs while still receiving lower revenue because of avoided demand charges.

Many of the stakeholders affirmed that ES could mitigate the risks of excessive demand charges and major upward shifts on peak demand due to the use of DCFC. In addition to a retail filling station, a large residential apartment complex might also receive the same financial benefits of having on-site storage with shared access to plug-in spots, though the plug-in usage pattern would likely be quite different. In the latter case, there would naturally be an emphasis toward more charging in evenings (i.e., after midnight) or to charge more slowly to benefit from lower demand charge costs.

Deploying ES at DCFC stations is especially impactful in areas of higher population density, including apartment dwellers where charging infrastructure would not normally be available. Moreover, by reducing the cost of charging for EV owners and removing one of the barriers to mass EV adoption this integrated method of deployment assists in the development of smart city initiatives across the State concerning clean energy and transportation.

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[41] Garrett Fitzgerald and Chris Nelder. 2017. "EVGO Fleet and Tariff Analysis: Phase 1, California." (*Rocky Mountain Institute Report, 2017*).
[42] Using ES to reduce demand charges would apply if no tariff changes are considered. Some have advocated for special tariffs that might support growth of DCFC infrastructure, though the higher power draw experienced (without local ES) would still require the EDC to build out transformers and other distribution equipment to meet the higher power rates – even when only used for short durations; having ES local to the DCFC means that the distribution grid might not need to be upgraded as soon.
[43] Fred Lambert. 2019."Tesla reaches deal with Electrify America to deploy Powerpacks at over 100 charging stations." (Reported online at Electrek.co, Feb 2019).

While the team has extensive data on EV ownership by zip code, the impact on the distribution networks requires more granular, specific neighborhood/network understanding that could help project when this added energy load will trigger T&D upgrades. Distributed ES could also provide value to the utilities by smoothing usage at the neighborhood level with growing EV ownership, but the financial value of deferred upgrades is difficult to quantify to balance against the cost of installing distributed ES. At present, the EV adoption numbers are a very small fraction of the electricity usage, but this could become a difficulty if EV ownership continues to grow rapidly into the future.

Vehicle-based ES has been suggested with V2G[44] and V2H systems. These systems allow the mobile storage to continuously (except when driving) participate in regular ES revenue streams, such as FR and arbitrage, though these systems can also provide power backup for grid outages, as well.[45] These approaches have the advantage that the ES is integrated into the ownership cost already, and the rapid growth of EV ownership suggests that the excess storage capacity that might be used for V2G or V2H modes would be accessible if equipment was appropriately outfitted. This area might be especially appropriate for early pilot studies as vehicle manufacturers enable the bi-directional power flow capabilities. Vehicle-to-grid is especially amenable to fleet implementation where known usage patterns leave sizable durations with plug-in availability (e.g., school buses).

Reduction in ES costs will likely go hand-in-hand with rising numbers of EVs in service: battery mass production leads to improvements in manufacturing that bring prices down and impact battery prices for all sectors of ES usage. The combination of innovation and cost reduction can, in turn, drive the demand for storage solely serving transportation demand, but also more cost-effectively meeting the many other ES values throughout the grid. Also, the reduction in the cost of renewable generation could improve the GHG abatement potential of EVs because of the gradual decrease in pollution and carbon footprint for grid electricity with time.

ES and Renewable Integration Opportunities

The inherent intermittency of renewable energy sources has led to the expectation that before the electric power network can handle high penetration rates of renewables, a parallel investment in ES may be necessary. However, tightly coupled development of renewables and ES is not immediately necessary because newer quick-acting gas turbines (or well-functioning DR contracts in buildings), can manage this variation, which in any case is damped by the inertia of the very large PJM Interconnection. Renewable installations in New Jersey have grown from 17 MW in 2005 to over 2,400 MW as of 2017, including 544 MW of utility-scale solar capacity. As of 2017-2018, there were 570.1 MW of contracted DR in the State and 3,483 MW of peaking capacity (e.g., gas turbines). To the extent that ES can provide similar functionality, it should be encouraged to bid into all the appropriate PJM markets. Consideration of various usage models will continue to drive the choice to install ES. Adding ES provides a greater ability to provide

[44] W. Kempton and J. Tomic. 2005. "Vehicle-to-grid power implementation: From stabilizing the grid to supporting large-scale renewable energy." (*Journal of Power Sources*. 2005; 144(1):280-94).
[45] K.S. Ko, S. Han, D.K. Sung. 2018. *Performance-Based Settlement of Frequency Regulation for Electric Vehicle Aggregators*. (IEEE Transactions on Smart Grid. 2018; 9(2):866-75).

rapid response to future renewable generation variability and should enable continued adoption of renewable energy sources throughout New Jersey and the region.

Energy storage may also couple with renewables to provide added resilience value at public locations that might be suitable for sheltering places for times of extended grid outage. High schools throughout the State are obvious targets as many already have PV arrays on their large roof spaces, and have large sheltering spaces (e.g., gymnasium, classrooms) and usually have food service preparation areas. The actual resilience value will depend on many factors including PV array size, battery size, sunlight variability, the establishment of emergency power circuits for operation in island mode, and normal facility power requirements. Figure 34 illustrates sunlight variability and battery size evaluation.[46] Solar power output changes dramatically from winter to summer and between clear and stormy days. Each data point in the figure gives one day's integrated sunlight exposure -- and the scatter highlights how bad cloudy days are in comparison with clear. The vertical axis gives the effective number of hours of full sunlight that would be logged for that day, integrating partial amounts for each daylight hour of the day. This number of hours would relate directly to the battery capacity choice and the resulting system's ability to provide resilient power through the seasons. For example, if a host site had a solar array with a rating of 200 kW and it was matched with a battery with a capacity of 1 MWh (i.e., five hours at 200 kW) its potential performance on any given day of the year would be referenced to that day's integrated hours of sunlight (y-axis units); many days in the summer would have more sunlight and therefore would easily fill the battery -- indicating that the nighttime and grid-outage performance would usually be limited by the storage space in the battery. In the winter, the weaker sunlight would rarely be able to fill a battery of that size, resulting in lower resilience host-site capability.

With net-metering restrictions in place, solar arrays throughout the State are required to be of limited size based on the facility's normal annual electricity usage -- implying undersupply by PV in the winter and oversupply of PV during the summer (feeding back into the grid, unless the array was designed smaller for cost considerations). Referring back to Figure 34 we can perform an annual average of the 365 days and find Newark's net-metering balance point is 4.1-hours of PV array output. This average is indicated by the dashed red line. If a facility is outfitted with the maximum PV allowed for net-metering annual break-even this dashed line will also provide a sense of what fraction of days the PV+Battery would be able to satisfy the building's normal energy needs, or if it might have to curtail energy consumption to provide community gathering/shelter and subsistence during the time of a major outage. For example a facility with battery storage limited to (two hours)*(PV rating) would need to survive on somewhat less than 50% of its normal usage compared to the average.

This figure also illustrates a seasonal upper limit on a location's energy supply in island mode. We can see in Figure 34 that the highest solar output occurs during the middle of the summer, reaching about eight hours of PV array peak yield. So, installing storage larger than eight hours would therefore not provide additional resilience benefit in island mode. On the other hand, winter PV yields are almost never over the 4.1-hours needed for normal site operation, and

[46] D. P. Birnie, III. 2014. "Optimal Battery Sizing for Storm-Resilient Photovoltaic Power Island Systems." (*Solar Energy*. 109, 165-173, 2014).

many days are as bad as or worse than one hour of energy yield only. It is interesting that bad weather days in the summer also experience many poor yield days.

The ES capacity choice is further complicated by the very likely need for dedicated emergency circuits within a facility (i.e., to allow for usage of the possibly quite limited energy available), and to add the automatic cut-off switches that would enable the facility to go into island mode. Ideal systems of ES+PV for resilience might best be designed especially for school locations that don't already have PV in place. Then, the sizing (of both ES and PV), circuiting, and emergency operation plans can be synchronized.

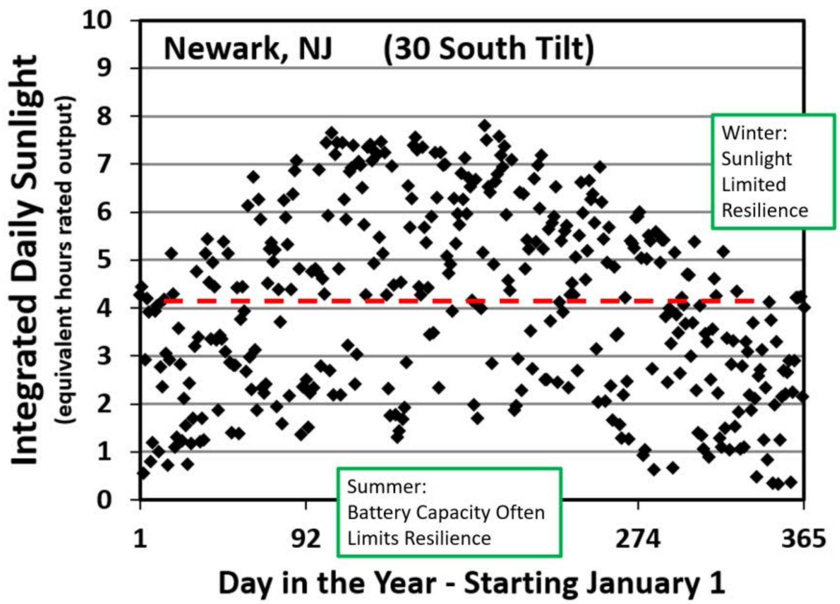

Figure 34: Day-by-day annual sunlight resource for a typical location in New Jersey based on direct and diffuse irradiance calculated for a southward tilt of 30 degrees. Data from NREL's "Typical Meteorological Year" database (figure adapted from Birnie 2014).

A further situation where ES can provide system value is to reduce grid impact when adding PV to already congested distribution network locations. If ES is deployed with PV the power fed into the grid can be spread through full 24-hour periods significantly reducing the power impact and enabling PV installations that now are being denied permits, or which would otherwise have required major grid improvements locally to accept the summer-time peak PV insertions. The impact of this can be illustrated in Figure 35, below. The brightest summer noon-time hours allow the array to deliver 100% of its rated output; a 3 MW PV array would then deliver 3 MW to the grid for those rare occasions. However, if a suitably sized battery was used to receive these large outputs and store the power for gradual insertion to the grid over the next 24-hour period we can reduce this substantially. Figure 35 above gives the daily totals, which then would be collected through the day and fed in gradually. The light green line shows the power distribution expected for sunlight variability typical of central New Jersey, as provided by NREL's Typical Meteorological Year database; essentially the battery can buffer the power generation and allow a 67% reduction in peak power by spreading the generated power all through the nighttime. So, a 3 MW PV array might behave more like 1 MW array from the grid's perspective. This is a strict upper limit as on-site power usage served by the array would subtract from the amount actually delivered to the grid, likely scaled by a further 50% reduction based on the eight hours summer max compared with the annual average of 4.1 (see Figure 34). Clearly, the seasonal facility usage patterns will matter in detail, but the combined effect of using ES to spread power delivery through full 24-hour periods and the local usage can reduce the apparent PV hosting grid impact by a factor of 1/6. One downside to this ES+PV smoothing functionality is the practical imposition of the round-trip-efficiency factor for energy collected by PV but stored to be delivered to the grid at a later hour. This reduces the energy generating value by perhaps 10-15%, depending on the battery chemistry and charge/discharge power. Of course, for PV that is well under the local facility's power demand, the net-metering back flow might never be reached and the lowering of power usage (PV+facility) should generally make it attractive to have PV be added (from the perspective of distribution network capacity limits).

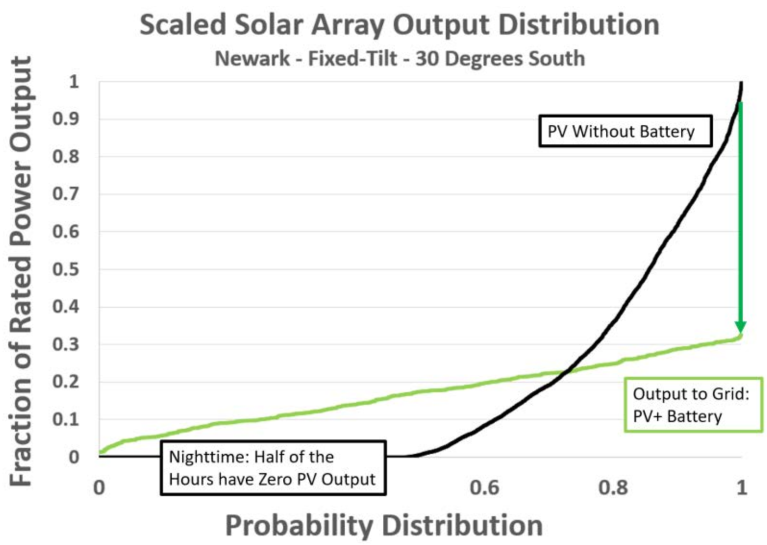

Figure 35: Cumulative probability distribution of hourly PV array output for 365 days of sunlight resource for a typical location in New Jersey based on direct and diffuse irradiance calculated for a southward tilt of 30 degrees. Data from NREL's "Typical Meteorological Year" database. Black line represents PV array alone with no output at night and a few hours in the summer of approximately 100% array output. Light green line represents the smoothing effect when each day's integrated PV output can be injected to the grid over a 24-hour period.

For this hosting capacity application, the ES would need to have a power rating of nearly the full PV power rating (reduced by summer season local facility's power demand during the peak mid-day sunlight hours). The ES capacity would need to be about 4 hours of the PV's rated output (for a maxed-out net-metered array) or somewhat larger for a grid-tied generating resource. The following discussion using simulations supports the benefits of ES in hosting capacity applications.

Also, at the distribution level, ES installation can support remote regions with radial distribution networks or high risks of power delivery interruption. The exact installation location is case-specific but coastal, or high altitude regions with critical facilities or difficult to reach locations are among possible options. Figure 36 (borrowed from Pepco maps and ACE territory) illustrates two candidates for resiliency applications at the distribution level. One shows a region with a high risk of interruption and the other is a remote radial system. ES sizing depends on the critical load of the service region, but at the same time, ES can have different applications such as wholesale market participation in addition to back-up support.

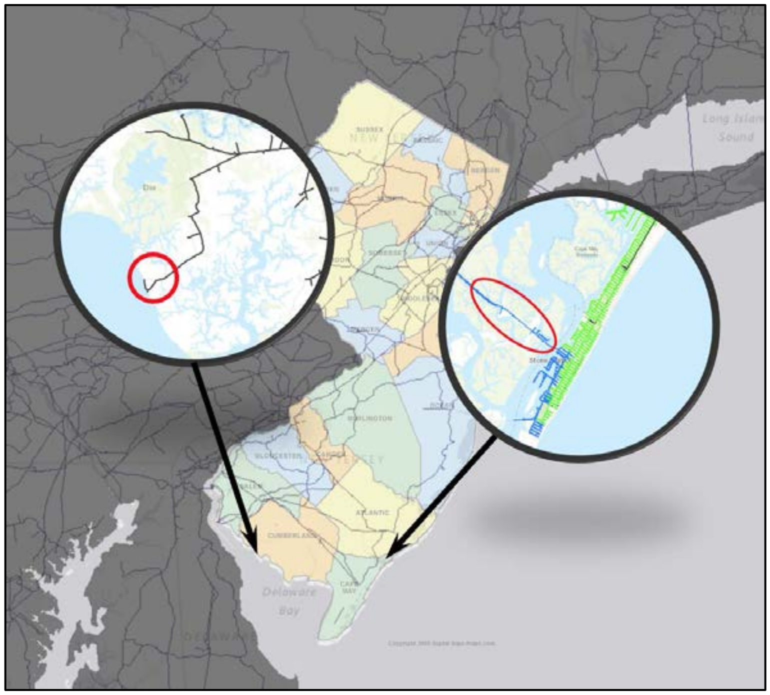

Figure 36: Potential ES installation for remote or prone to high risk of interruption.

There may be business opportunities to stack up against the distribution network value impacts of ES with those at a customer site. For instance, a utility owned ES installed at a customer site can serve both customer level objectives (e.g., resiliency or EBM) and network level objectives. A collaboration between customers and the utility that optimizes control of ES charge and discharge can maximize benefits to both. This ESA project does not deal with issues and regulatory challenges that such an application may pose. The regulatory and policy challenges for such collaboration may be addressed in the proposed pilot program.

ES Impact on PV investment in Distribution Networks

Combined ES/PV or standalone ES systems can mitigate power outage risks, help reduce peak loads, and serve the network at the distribution level. Energy storage can also serve as a driver for more PV installation at the distribution level. These conjectures along with ES configuration (decentralized or centralized) are examined here. The analysis includes multiple simulation scenarios with centralized and decentralized ES configurations and two objectives: (a) technology investment optimization and (b) network operation optimization. Each scenario has three possibilities: 1) Only PV investment is allowed, 2) Both PV and ES investments are allowed, and 3) Only ES investment at substation level is allowed. Three distribution networks (see Figures in Technical Approach Section) in three different EDC territories were used.

ES improves PV investment at the distribution network level as indicated in Table 7. Nodal level improvements with and without ES are shown in Figure 37 and centralized scenarios are depicted in Figure 38. These improvements are dependent on network configuration and load profiles. Table 8 illustrates peak load reduction and power import reduction savings for all scenarios in case of normal operation. Table 9 and Table 10 present ES impact on improving avoided load loss for short and long duration outage events.

Table 7: PV investment in presence and absence of ES for three different distribution configurations.

<table>
<tr><th rowspan="3" colspan="2"></th><th colspan="3">ES supporting PV investment</th><th>PV- No ES</th><th rowspan="3">ES only (kW)</th></tr>
<tr><th rowspan="2">Total PV Investment (kW)</th><th colspan="2">Total ES Investment</th><th rowspan="2">Total PV Investment (kW)</th></tr>
<tr><th>ES Capacity (kW)</th><th>Average ES Duration (hour)</th></tr>
<tr><td rowspan="3">Centralized</td><td>Network 1</td><td>2,523</td><td>359</td><td>4</td><td>2,019</td><td>-</td></tr>
<tr><td>Network 2</td><td>459</td><td>130</td><td>4</td><td>284</td><td>-</td></tr>
<tr><td>Network 3</td><td>3,340</td><td>618</td><td>4</td><td>2,364</td><td>-</td></tr>
<tr><td rowspan="3">Decentralized</td><td>Network 1</td><td>2,510</td><td>89</td><td>4</td><td>1970</td><td>-</td></tr>
<tr><td>Network 2</td><td>486</td><td>39</td><td>4</td><td>257</td><td>-</td></tr>
<tr><td>Network 3</td><td>3,061</td><td>198</td><td>4</td><td>1,690</td><td>-</td></tr>
<tr><td rowspan="3">ES only at substation</td><td>Network 1</td><td>-</td><td>-</td><td>-</td><td>-</td><td>359</td></tr>
<tr><td>Network 2</td><td>-</td><td>-</td><td>-</td><td>-</td><td>130</td></tr>
<tr><td>Network 3</td><td>-</td><td>-</td><td>-</td><td>-</td><td>618</td></tr>
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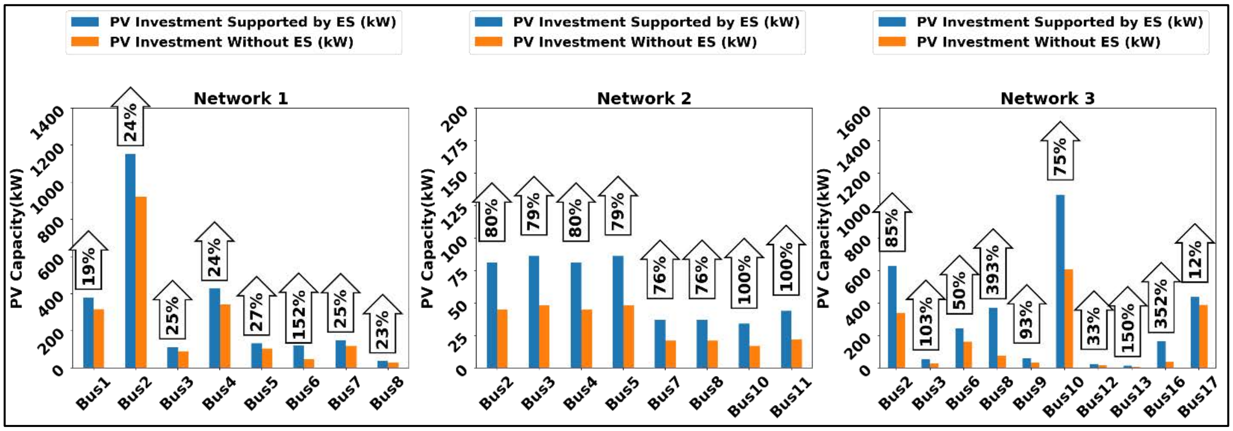

Figure 37: PV investment improvement supported by ES for decentralized network configuration.

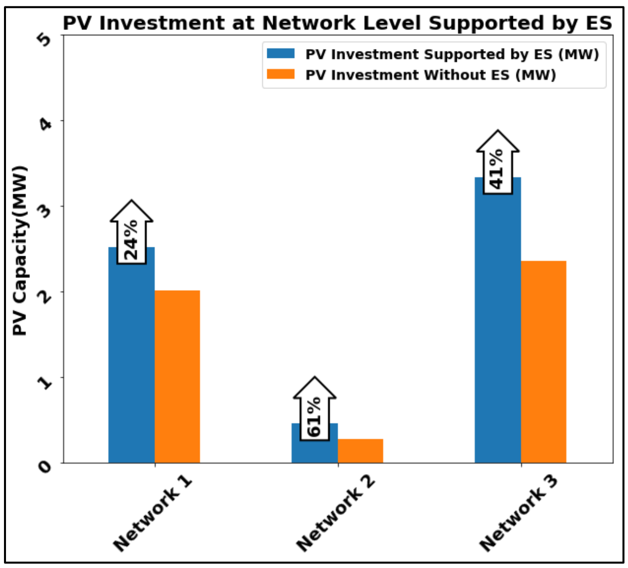

Figure 38: PV investment improvement supported by ES for centralized network configuration.

Table 8: Aggregate impact of ES on peak load reduction and local power generation applications.

		PV/ES Operation			
		Import Reduction (MWh)	Peak Load Reduction (kW)	Import Reduction Savings ($)	Peak Load Reduction Savings ($)
Centralized	Network 1	633	303	37,927	53,579
	Network 2	248	120	14,153	21,472
	Network 3	251	643	128,161	116,959
Decentralized	Network 1	704	282	40,909	50462
	Network 2	312	141	17,502	25164
	Network 3	308	815	154,711	148027
ES only at substation	Network 1	-210	138	-2,234	24,889
	Network 2	-49	105	616	18,547
	Network 3	-376	403	-4,766	71,897

Table 9: ES/PV at distribution level for resiliency in short duration outage events.

		Average Avoided Loss Load (kWh)
Centralized	Network 1	989
	Network 2	323
	Network 3	326
Decentralized	Network 1	986
	Network 2	389.9
	Network 3	395
ES only at substation	Network 1	610
	Network 2	220
	Network 3	151

Table 10: ES/PV at distribution level for resiliency in long duration outage events.

		Average Avoided Loss Load (kWh)
Centralized	Network 1	11,023
	Network 2	3,849
	Network 3	36,295
Decentralized	Network 1	11679
	Network 2	4816
	Network 3	44933
ES only at substation	Network 1	-
	Network 2	-
	Network 3	-

Element 3

Study the types of energy storage technologies currently being implemented in the State and elsewhere

Summary of Findings

This ES technology evaluation has revealed a range of ES possibilities for the entire spectrum of utility needs ranging from FR to peak shifting, to enabling a new energy landscape of renewable energy with stabilized power delivery. Today, there exists an ES technology that can address the breadth of power requirements represented by these applications, and can do so for at least 10 years lifetime. As this report details, in many cases, there exist electrochemical energy technologies where a single technology can actively address all of these needs and in scale.

The research team assessed a wide portfolio of electric energy storage technologies that are commercially available and near commercially available, to determine their suitability for grid applications in New Jersey. Various types of electric energy storage appropriate for utility-connected applications were evaluated, including mechanical, thermal, electrochemical, and chemical technologies. Besides the ubiquitous pumped hydro storage, other ES solutions exist today that have been successfully implemented on scales in excess of 100 MW and 100 MWh per installation, nationally and internationally, to address the spectrum of utility needs including FR, peak shifting, renewable integration, and resilience. Pumped hydro storage (PHS) is a mature and commercial technology, which accounted for over 90% of ES capacity installed in the United States in 2017 at 22.6 GW. Pumped hydro storage still has the lowest lifetime cost of installation, a benefit of utilizing natural geographic conditions. Pumped hydro storage represents the majority of New Jersey's present ES capacity with 420 MW at Yards Creek. Opportunities to implement new installations are restricted by the unique geographical requirements.

Thermal storage is another mature technology which effectively results in a peak shifting of energy usage. At least 9.5 MW of thermal storage has been installed in New Jersey in the form of ice energy storage. Costs are currently lower than lithium ion (Li-ion) storage. Broader impacts in service of utility needs, such as FR and resiliency, are not readily feasible with thermal storage. However, lower costs and risks may make this an attractive approach for adoption within cities and communities with expanding commercial entities.

Li-ion technology, with a downward trend in battery cost, is the fastest growing technology being implemented today. This technology is viewed favorably due to its ability to address a number of utility applications from fast-response FR to longer-duration peak shift and resiliency. A general trend has been developing towards the 4-hour power delivery for reasons described in detail within this report. Over 100 MWh installations for Li-ion batteries are becoming common, and new installations above 500 MWh are in existence even for next-generation battery technology such as high-temperature NaS batteries. Most of the total 44.5 MW of Li-ion systems installed in New Jersey remain short-duration (less than one hour), allowing participation in ancillary services markets or as an emergency back-up, with or without a renewable power source. Li-ion battery technology has been proven in the utility space with large installations. Significantly falling prices of the Li-ion technology combined with the ability to address all aspects of utility time responses from short pulses to long duration discharges make this technology highly attractive for present-day installations. There is a continued pressure to reduce the cost and price of these installations. It cannot be understated that only about 35% of the installed cost of utility ES is related to the electrochemical energy storage technology in the case of Li-ion batteries. As such, although prices of electrochemical energy technologies need to and will continue to decrease, the most significant part of the costs lie in site construction and integration of these systems. As such, programs need to be introduced to address this significant hurdle to reducing cost. To reduce costs of construction and enable reconfiguration for resiliency, a move to prefabricated modular systems, which can be made mobile, would be attractive.

Commercial high-temperature sodium sulfur battery technology represents the world's largest integration of electrochemical energy storage, rated at 108 MW and 648 MWh. This technology offers future cost reduction opportunities due to the intrinsically very low cost of the chemicals utilized. Sodium sulfur is especially attractive for long durations and continuous-use applications. Next generation ZEBRA technology may offer added robustness. Redox flow technology is one technology, which can also offer much on the next generation landscape due to easy reconfiguration and potentially, but not yet realized, outstanding economies of scale relative to battery technologies such as Li-ion.

Emerging flow battery technologies are very attractive for large installations due to their intrinsically cost-effective ability to be scaled into large tanks and subsequent power system versatility by effectively decoupling power from energy. China has moved quickly on flow batteries as its 2017 ES policy requires the deployment of multiple 100 MW-scale vanadium flow batteries. Also, a 200 MW/800 MWh system is currently under construction in Dalian, China, to be commissioned in 2019. Energy storage in the form of hydrogen fed into the utility through fuel cells offers a very low materials cost with very low environmental impact. However, one must consider the cost of poor conversion efficiencies of energy into hydrogen either by direct electrolysis or renewables relative to pure electrochemical systems offering direct electron storage.

The total ES presently in New Jersey amounts to approximately 477 MW, including a 0.5 MW lead-acid asymmetric hybrid system. Of that total, 420 MW is pumped hydro from a 54-year old facility. However, there are many ES opportunities in New Jersey. For additional ES, PHS would provide the lowest lifetime cost and massive scalability (>GW), but it will require an adequate geographical site, high capital cost, and long construction time. Despite the site restrictions, NJ is very well situated to take advantage of PHS especially in the northern sections of the state where geo-topography and abandoned mines offer much documented opportunity. Some of these geographical features may be advantageous to compressed air energy storage also. Li-ion battery technology is the current mainstream technology, but sodium sulfur and flow batteries have many benefits specifically for longer durations. As opposed to pumped hydro storage, most batteries discussed herein are flexible, modular, and standalone containers that facilitate deployment and trending towards mobility (especially for Li-ion). In addition, installation can be operational within a few months. As such, there are many opportunities for battery deployments in New Jersey. Thermal storage offers cost-effective peak shifting of energy and could be an excellent avenue to reduce daytime stresses on the grid in expanding cities, but do not offer added benefits of resiliency and addressing other utility markets.

Analysis and Discussion

Pumped hydroelectricity, one of the oldest methods of ES (Figure 39) is presently the largest source of electric energy storage at approximately 169 GW (Figure 40) totaling 96% of the 176 GW global capacity in 2017. Thermal storage, which consists of chilled water, water heat, concrete heat, ice and molten salt storage, provided 3.3 GW equivalent to 1.1% of the total capacity. Electrochemical energy storage followed with 1.1 GW and 0.9% of global capacity. Mechanical energy storage, which encompasses flywheel and compressed air storage, generated 1.1 GW of power accounting to 0.9% of total energy. Finally, the chemical energy storage contribution, consisting of hydrogen and liquid air energy storage, was negligible (Figure 40).

All technologies within the mechanical (including pumped hydro), thermal, electrochemical, and chemical categories provide a wide range of beneficial attributes that can address different needs of the grid's infrastructure and off-grid networks. As such, a portfolio of several technologies could provide the best strategy to achieve a reliable and resilient grid, integrating increasing amounts of destabilizing variable renewable power sources. The distinct intrinsic technical properties of the various technologies are assessed to determine their suitability for specific applications. Implementation of these technologies and demonstrations of specific applications are evaluated through national and international case studies, and literature review. And as a result, selected technologies are determined for most suitable applications within the State of New Jersey.

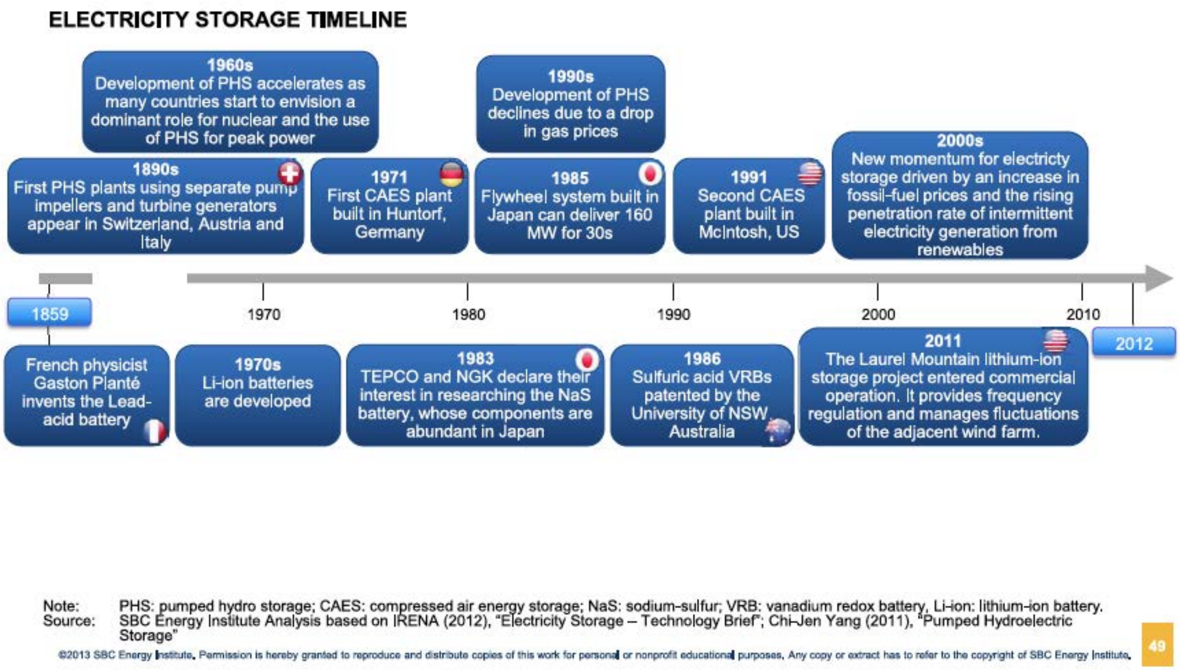

Figure 39: Electricity storage timeline.[47]

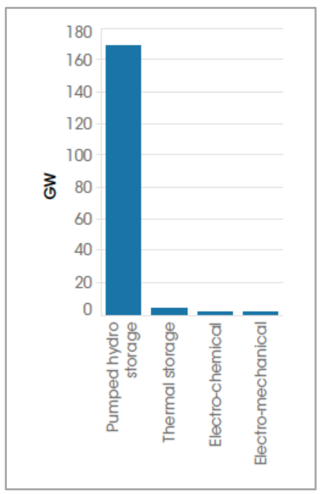

Figure 40: Global operational energy storage power by technology group in mid-2017.[48]

[47] Schlumberger Business Consulting (SBC) Energy Institute. 2013. Leading the Energy Transition, The Electricity Storage Factbook. (September 2013 http://energystorage.org/system/files/resources/sbcenergyinstitute_electricitystoragefactbook.pdf).
[48] IRENA. 2017. "Electricity storage and renewables: Costs and markets to 2030." International Renewable Energy Agency, Abu Dhabi. (https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf).

Electrical mechanical energy storage

The most common mechanical energy storage technologies consisted of the prevalent pumped hydro storage, compressed air energy storage and flywheel energy storage.

Pumped hydro storage (PHS)

Pumped hydro storage was first used in the 1890s in the Swiss, Austrian, and Italian Alps to provide greater flexibility for the management of water resources (Figure 39).[49] The Rocky River plant installed in 1929 on the Housatonic River, in Connecticut, was the first deployed in North America. The systems had been quite basic so far comprising a motor and pump on one shaft, and a generator and turbine on a separate shaft. By 1956, TVA developed a much larger system, Hiwassee, rated at 59.5 MW in North Carolina, with the first reversible pump/turbine. Further developments and advancement resulted in larger systems that are more rapidly deployed in the 1960s (Figure 39), which become more common through the 1980s. After the gas price dropped in the mid-1980s, the construction of PHS systems leveled off in the United States (Figure 39). However, the increase in gas prices in 2000 revived the interest in all forms of ES, including PHS (Figure 39).

Pumped hydro storage is a proven, mature, and commercially available utility-scale technology. As previously mentioned, PHS is the largest source of ES, globally and in the United Stated, with 169 GW (Figure 40) and 22.6 GW of installed capacity of installed capacity, respectively, in 2017.[50]

The traditional PHS system consists of two reservoirs, with a height differential, and a pipe/penstock connecting them (Figure 41). During charge, typically during off-peak hours, the water is pumped from the lower to the upper reservoir. When electricity is needed, the water is allowed to flow back from the upper to the lower reservoir, powering a turbine with a generator, thereby producing electricity (discharge). The rated power and energy are defined by two factors: the height differential between the two reservoirs (also the "head"), and the volume of the reservoirs (the "flow"). More energy can be generated when the height and volume are larger. As the flow of the water through the pipe/penstock increases, more power is generated.

If the upper or the lower reservoir has access to a free flowing source of water then the PHS is open loop. Most of PHS systems in the United States are open loop. A few other systems already installed in the United Stated and currently under development are closed loop.[51] In this configuration, both reservoirs are isolated from a free flowing source of water (Figure 41). Its main advantage is less environmental impact. There is no significant transfer of water from a free flowing source after the initial filling of the reservoir, thereby greatly reducing aquatic issues

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[49] J. Roach. 2015. "For storing electricity, utilities are turning to pumped hydro." (*YaleEnvironment360*. November 24, 2015. Accessed May 15, 2019. https://e360.yale.edu/features/for_storing_electricity_utilities_are_turning_to_pumped_hydro).

[50] IRENA. 2017. "Electricity storage and renewables: Costs and markets to 2030." International Renewable Energy Agency, Abu Dhabi. (https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf).

[51] FERC. "Pumped Storage Projects." Federal Energy Regulatory Commission. (Accessed May 15, 2019. https://www.ferc.gov/industries/hydropower/gen-info/licensing/pump-storage.asp).

(fish passage, sediment migration, etc.). If the two reservoirs are man-made, then there is no aquatic life. However, one should still consider the impact on local wildlife if it applies.[52]

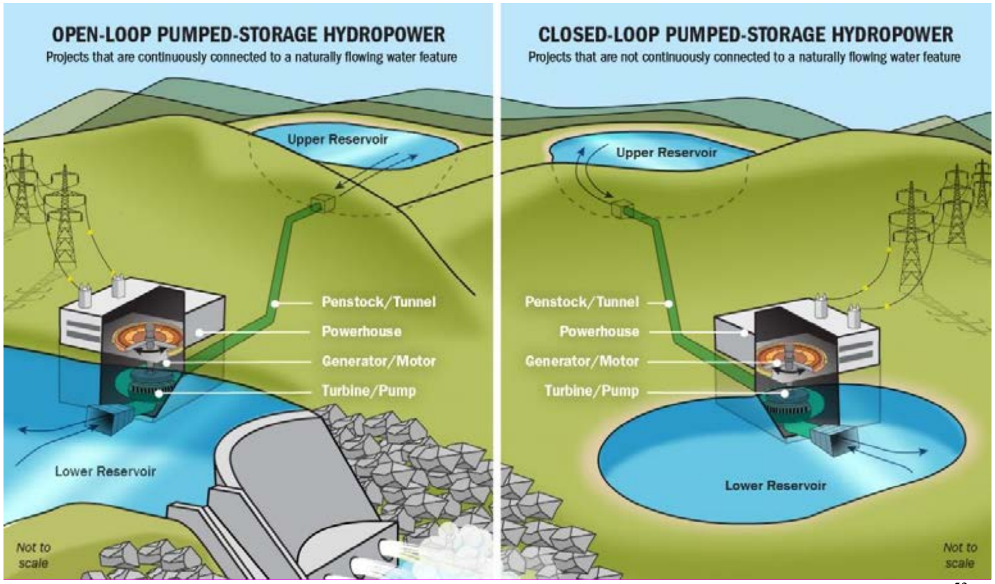


Figure 41: Schematics of open-loop (left) and closed-loop (right) pumped hydro energy storage.[53]

There has been an increase in the number of permit applications filed at the Federal Energy Regulatory Commission (FERC) for PHS projects in 2016, illustrating the renewed interest in the technology. Figure 42 reveals a total of 22 projects totaling 18,000 MW, with 70% located in the Western Interconnection area. More than half of the preliminary permit applications are based on a closed-loop design.[54]

[52] Energy Storage Association. "Surface reservoir Pumped Hydroelectric Storage". (Accessed May 15, 2019. http://energystorage.org/energy-storage/technologies/surface-reservoir-pumped-hydroelectric-storage).
[53] Office of Energy Efficiency & Renewable Energy. "Water Power Technologies." (Accessed May 15, 2019. https://www.energy.gov/eere/water/pumped-storage-hydropower).
[54] Federal Energy Regulatory Commission. 2019. "Closed-loop pumped storage projects at abandoned mine sites workshop." (Presentation. April 4, 2019. Accessed May 15, 2019. https://www.ferc.gov/CalendarFiles/20190404080302-CLPS%20workshop%20presentation_04042019.pdf).

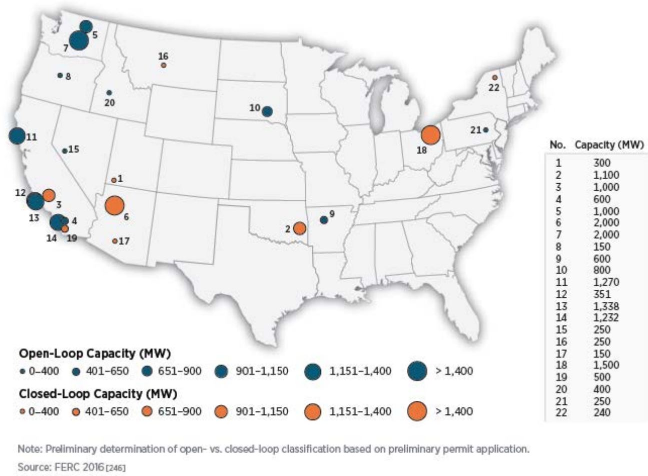


Figure 42: Preliminary permits for pumped hydro storage in the United States.[55]

Technology:

PHS systems can store energy with high efficiency (70–85%) over long periods of time; typical discharges time can range from a few hours to a few days. Self-discharge is negligible (0.0–0.02%).[56] In addition, the system takes a few minutes to fully turn on, but it only takes seconds of response time.[57] The cycle life is basically unlimited (> 50,000 cycles), and the lifespan of the installation is over 50 years, but some have reach up to 100 years.

The main drawbacks of these systems are very low densities, including specific energy at the 0.2–2.0 Wh/kg, energy density at 0.2–2.0 Wh/L, and power density at 0.1–0.2 W/L. The requirement for a large footprint combined with the need for high differential elevation leads to a great dependence on topographical conditions difficult to meet resulting to a lack of suitable sites.

Environmental Impact:

Due to its low energy density, PHS technology's environmental impact is high, as it requires large amounts of water and large footprint. PHS impact is significant on local wildlife, if any reservoir needs to be constructed. In addition, the fluctuation of water level in the reservoirs also significantly affects all aquatic life. Seawater PHS would alleviate some of the environmental effects.

[55] National Hydropower Association. 2018. " 2018 Pumped storage report." (https://www.hydro.org/wp-content/uploads/2018/04/2018-NHA-Pumped-Storage-Report.pdf).
[56] International Electrotechnical Commission (IEC). 2011."Electrical Energy Storage Whitepaper." (*IEC White Papers and Technology Reports*. https://www.iec.ch/whitepaper/energystorage/).
[57] Business Consulting (SBC) Energy Institute. 2013. "Leading the Energy Transition, The Electricity Storage Factbook." (Presentation. September 2013. http://energystorage.org/system/files/resources/sbcenergyinstitute_electricitystoragefactbook.pdf)ploads/2018/04/2018-NHA-Pumped-Storage-Report.pdf).

Case Studies:

In 2015, forty PHS plants were in operations in the United States. Figure 44 shows the location and size of each plant in the territory. The PHS systems range from 8.5 MW, the Flatiron Powerplant in Colorado, to 3003 MW, the Bath County Pumped Storage, in Virginia. Yards Creeks, the only PHS plant located in New Jersey, with an installed capacity of 420 MW, commenced commercial operation in 1965. Indeed, many of these plants were constructed from the 1960s through the 1980s, to complement nuclear and coal power generation. Originally, PHS systems provided load shifting from peak to off-peak hours, served as backup capacity in the case of power outages from nuclear and coal generation. [58]

PHS technology is presently reliable, versatile, provides a wide range of services, and is the lowest cost ES technology at less than $150/kWh (Figure 43) It provides various ancillary grid services. It participates in FR, but only during generation, and provides voltage support. Its reserve capacity enables power stability, quality and reliability. PHS can also participate in load leveling/energy arbitrage, which can provide additional revenue. One of the main roles of PHS is the use of its contingency energy reserves, which can be quickly dispatched in case of outage, as mentioned above. Finally, depending on the location of the PHS system, it can also defer the need for investments in new transmission capacity. Finally, PHS can also store surplus variable renewable generation, thereby reducing curtailments, and further help with the integration of variable renewable power generation into the grid.

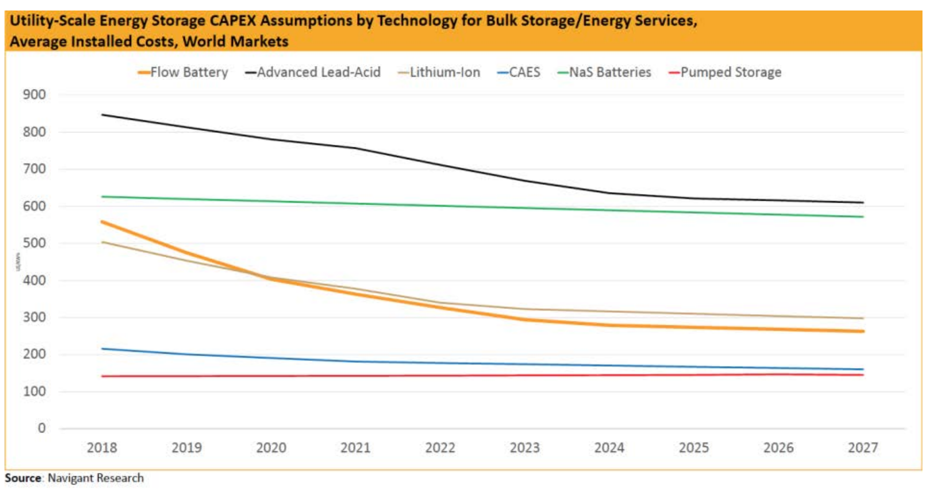


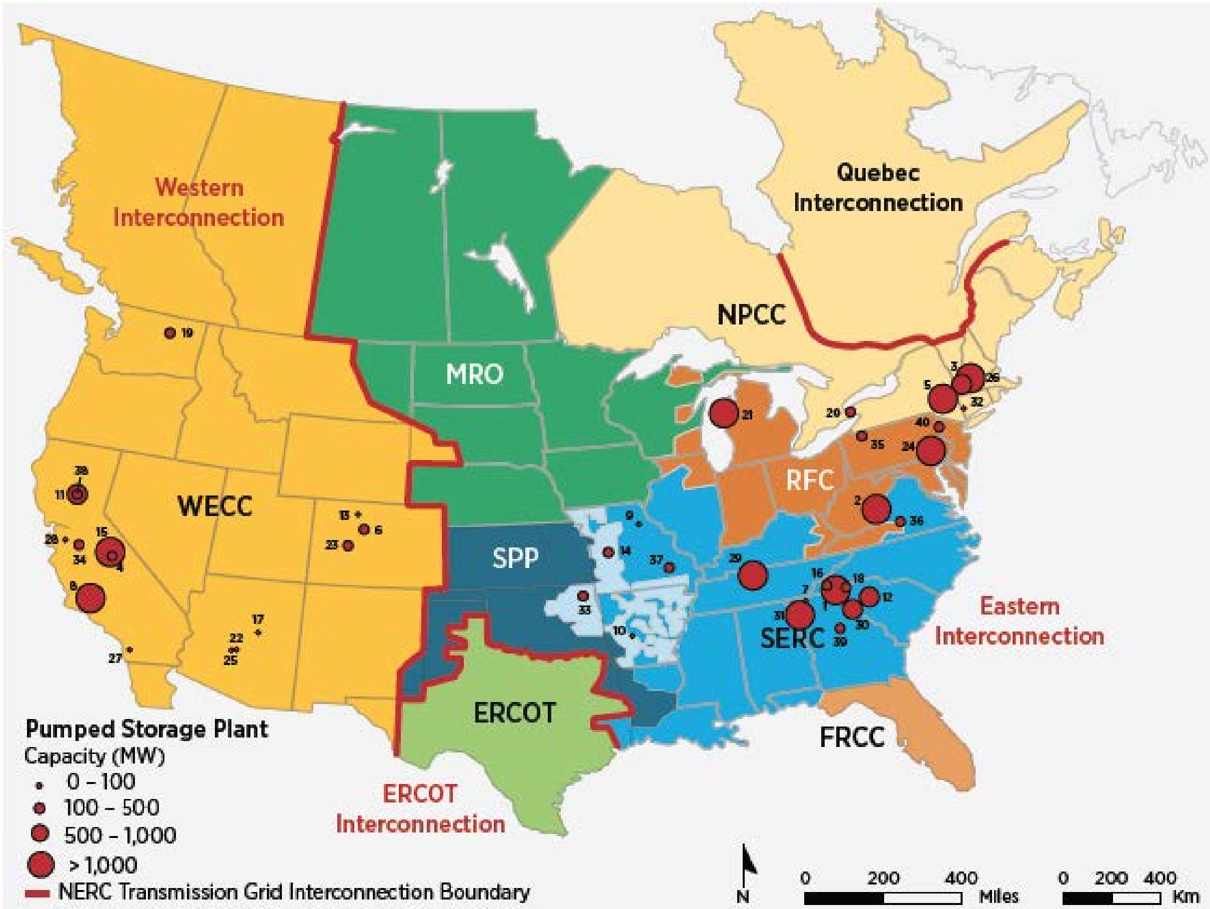
Figure 43: Average installed costs for bulk energy storage services by technology, for flow batteries, advanced lead-acid batteries, Li-ion batteries, compressed air energy storage (CAES), sodium sulfur (NaS) batteries and pumped hydro storage between 2018-2027.[59]

[58] National Hydropower Association. 2018. " 2018 Pumped storage report." (https://www.hydro.org/wp-content/uploads/2018/04/2018-NHA-Pumped-Storage-Report.pdf).

[59] Bushveld Minerals. 2018. "Energy storage & vanadium redox flow batteries 101." November 13, 2018. (Accessed April 26, 2019 http://www.bushveldminerals.com/wp-content/uploads/2018/11/Energy-Storage-Vanadium-Redox-Flow-Batteries-101.pdf).

New technological advances, such as the adjustable speed technology, expand capabilities over a wider operating range, or enable new capabilities. Indeed, adjusted-speed systems can participate in the FR even during pumping. These improved systems have in general improved power system stability and reliability. Such innovation, in turn, improves the PHS ability to integrate renewable power resources. The adjustable PHS technology has been developed in Japan in the 1990 and several systems have already been deployed in Japan and in the United States. [60] Many of the projects, which have applied for a preliminary permit (Figure 42), are considering the use of adjustable-speed technology, which can be used in both closed- and open-loop configurations. Fixed-speed systems could also be converted to advanced adjustable-speed. Some limitations apply, and not all systems can be converted. Yet, several systems have been converted successfully internationally. However, as of 2015, but none were converted in the United Stated.

[60] National Hydropower Association. 2018. "2018 Pumped storage report." (https://www.hydro.org/wp-content/uploads/2018/04/2018-NHA-Pumped-Storage-Report.pdf).



NERC Regions

ERCOT: Electric Reliability Council of Texas
FRCC: Florida Reliability Coordinating Council
MRO: Midwest Reliability Organization
NPCC: Northeast Power Coordinating Council
RFC: ReliabilityFirst Corporation
SERC: SERC Reliability Corporation
SPP: Southwest Power Pool
WECC: Western Electricity Coordinating Council

Notes: The Alaska Systems Coordinating Council (ASCC) is an Affiliate NERC member. Commercial electric power providers in Hawaii are not affiliated with NERC.

No.	Name	Capacity (MW)
1.	Bad Creek Pumped Hydro Storage	1,065
2.	Bath County Pumped Storage Station	3,030
3.	Bear Swamp Hydroelectric Power Station	600
4.	Big Creek (John S. Eastwood) Pumped Storage	199.8
5.	Blenheim-Gilboa Pumped Storage Power Project	1,160
6.	Cabin Creek Generating Station	324
7.	Carters Dam Pumped Storage	250
8.	Castaic Pumped-Storage Plant	1, 247
9.	Clarence Cannon Dam Pumped Storage	58
10.	DeGray Lake Pumped Hydro Storage	28
11.	Edward Hyatt (Oroville) Power Plant	819
12.	Fairfield Pumped Storage	511.2
13.	Flatiron Powerplant	8.5
14.	Harry S. Truman Pumped Hydro Storage	161.4
15.	Helms Pumped Hydro Storage Project	1,212
16.	Hiwassee Dam	185
17.	Horse Mesa Pumped Hydro Storage	97
18.	Jocassee Pumped Hydro Storage	710
19.	John W. Keys III Pump-Generating Plant	314
20.	Lewiston Pump-Generating Plant	240
21.	Ludington Pumped Storage	1,872
22.	Mormon Flat Pumped Hydro Storage	50
23.	Mount Elbert Power Plant	200
24.	Muddy Run Pumped Hydro Storage	1,070
25.	New Wadell Dam Pumped Hydro Storage	45
26.	Northfield Mountain Pumped Storage Hydroelectricity Facility	1,119
27.	Olivenhain-Hodges Storage Project	40
28.	O'Neill Powerplant	25.2
29.	Raccoon Mountain Pumped Storage	1,652
30.	Richard B. Russell Pumped Storage	600
31.	Rocky Mountain Hydroelectric Plant	1,095
32.	Rocky River Pumped Storage Plant	29
33.	Salina Pumped Storage Project	260
34.	San Luis (William R. Gianelli) Pumped Storage Hydroelectric Powerplant	424
35.	Seneca Pumped Storage Generation Station	440
36.	Smith Mountain Pumped Storage Project	247
37.	Taum Sauk Hydroelectric Power Station	440
38.	Thermalito Pumping – Generating Plant	120
39.	Wallace Dam Pumped Storage	208
40.	Yards Creek Pumped Storage	400

Source: Argonne National Laboratory

Figure 44: Existing pumped storage hydropower plants in the United States.[61]

[61] National Hydropower Association. 2018. "2018 Pumped storage report." (https://www.hydro.org/wp-content/uploads/2018/04/2018-NHA-Pumped-Storage-Report.pdf).

A ternary configuration has been developed with a hydraulic bypass. This type of system can regulate the power that is supplied to the pump from the grid by varying the power output of the turbine. As a result, the system can operate across a wider range of power consumption levels, and the system can react much faster than the other two configurations. Three ternary-system rated at 150 MW have been installed in Europe, and others are planned or under construction. [62]

Other developments have targeted the design of the PHS installations to alleviate the stringent geographical requirements and open more opportunities where PHS systems can be installed.

Underground PHS uses a lower reservoir located below ground, which can consist of old mineshafts, depleted natural gas formations, tanks, or excavated caves. Such configuration could enable the introduction of PHS in flat regions. It could also potentially lower environmental impact. In addition, the almost vertical penstock would reduce energy losses as water can flow without friction. There is no underground PHS deployment to date. The Mount Hope project, located in Rockaway Township of Morris County, New Jersey, which was first proposed in 1975, intended to use the water from an inactive iron mine of Mount Hope Mine Complex. A closed-loop license was issued in 1992 (P-9401) for the 2000 MW Mount Hope project. [63, 64] However, the license was terminated in 2005, resulting from failure to commence construction. Mount Hope Waterpower Project LLP applied for a new preliminary permit, which was immediately dismissed by FERC in June 2006 on the grounds that they held a license, which they failed to concretize.[65] Finally, Reliable Storage 2, LLC filed an application for a 36-month preliminary permit in 2011 to study the feasibility of the 1000 MW project at Mount Hope.[66] There is no active preliminary permit on for Mount Hope. There were also two other projects 1990s that lost their license also for failure to start construction within timelines. However, a new license was finally issued (P-13123) in 2014 for a 1300 MW closed-loop project in Eagle Mountain, California. This project is also located at an abandoned mine. Such is the 240 MW project proposed in Mineville, New York with an application currently under process, filed in 2015 (P-12635).[67]

Seawater PHS uses the sea as its lower reservoir. Such configuration significantly increases the number of potential sites that would be available. However, some of the main drawbacks of this design include corrosion of the equipment by the sea salt, and ecologic impact

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[62] National Hydropower Association. 2018. "2018 Pumped storage report." (https://www.hydro.org/wp-content/uploads/2018/04/2018-NHA-Pumped-Storage-Report.pdf).

[63] Federal Energy Regulatory Commission. 2019. "Closed-loop pumped storage projects at abandoned mine sites workshop." (Presentation. April 4, 2019. Accessed May 15, 2019. https://www.ferc.gov/CalendarFiles/20190404080302-CLPS%20workshop%20presentation_04042019.pdf).

[64] U.S. Federal Energy Regulatory Commission. 2007. "Order dismissing appeal of annual charges statement and denying request for waiver of annual charges." (Project No. 9401-065. June 21,2007. https://www.ferc.gov/whats-new/comm-meet/2007/062107/H-1.pdf).

[65] U.S. Federal Energy Regulatory Commission. 2006. "Order dismissing preliminary permit application." (Project No. 12641-000. June 15, 2006. https://www.ferc.gov/whats-new/comm-meet/061506/H-1.pdf).

[66] U.S. Federal Energy Regulatory Commission. 2011. "Order issuing preliminary permit and granting priority to file license application." (Project No. 14114-000. August 1, 2011. https://www.nrc.gov/docs/ML1409/ML14093A284.pdf).

[67] Federal Energy Regulatory Commission. 2019. "Closed-loop pumped storage projects at abandoned mine sites workshop." (Presentation. April 4, 2019. Accessed May 15, 2019. https://www.ferc.gov/CalendarFiles/20190404080302-CLPS%20workshop%20presentation_04042019.pdf).

from mixing sea salt water to the upper reservoir. The first seawater PHS unit is the Okinawa Yanbaru seawater pumped storage power station located in Kunigami, Okinawa, Japan, which has been operational since 1999, and is rated at 30 MW.[68] In 2015, United Power Corp. filed a preliminary permit with FERC for a 30 MW project that would use seawater from the Pacific Ocean to power the installation based on the south coast of Maui Island, Hawaii.[69]

Other concepts are also under developments such as the aquifer PHS that uses permeable aquifers, which have reservoir-like characteristics, as the lower reservoir. There had been no project built following this configuration by 2015. The "Energy Islands" PSH design is built directly on the water using a ring dike to store the excess energy of the wind turbine of the North Sea. Finally, in-ground storage pipe PHS (Figure 45) consists on a large storage shaft housing a large piston built from pancakes of concrete and iron allowed to move vertically without friction. A return pipe allows for the water to be "pumped" up and flow down in order to store and generate electricity. Prototypical layouts enable up to 2.4 GW per 2.5-acre footprint, with shafts extending 2,000 meters below the surface.[70]

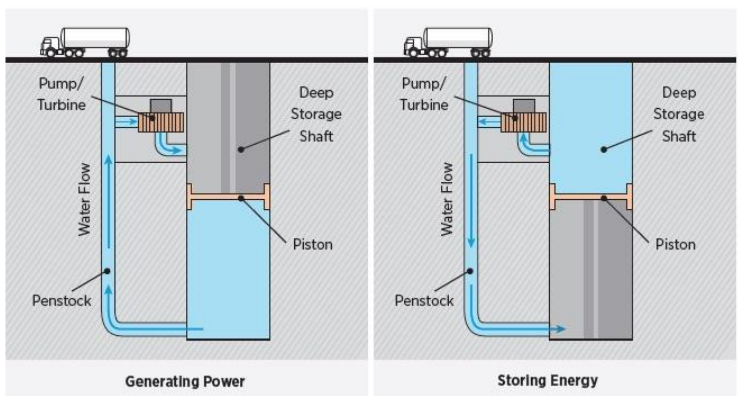

Figure 45: Schematics of an in-ground storage pipe pumped hydro storage system during power generation (left) and energy storage (right).[71]

Finally, modular PHS may have many benefits over large designs. Modular PHS would be smaller, more easily deployable, of lower investment costs, more easily financed, of lower development risk, potentially shorter permitting/licensing/construction process, less environmental impact. Designs of potential modular PHS have already been developed. However, the benefits of modularization have not yet been clearly quantified and may not outweigh the economies of scale inherent in the previously large-scale installation. In addition,

[68] S. Pritchard. 2019. "Japanese pumped storage embraces the ocean waves." (*Water Power & Dam Construction.* August 14, 2000. Accessed May 15, 2019. https://www.waterpowermagazine.com/features/featurejapanese-pumped-storage-embraces-the-ocean-waves/).
[69] Hydro Review. 2015. "FERC receives permit application for seawater-powered Hawaii pumped-storage." (January 21, 2015. Accessed May 15, 2019. https://www.hydroworld.com/articles/2015/01/ferc-receives-permit-application-for-seawater-powered-hawaii-pumped-storage.html).
[70] National Hydropower Association. 2018. " 2018 Pumped storage report." (https://www.hydro.org/wp-content/uploads/2018/04/2018-NHA-Pumped-Storage-Report.pdf).
[71] National Hydropower Association. 2018. " 2018 Pumped storage report." (https://www.hydro.org/wp-content/uploads/2018/04/2018-NHA-Pumped-Storage-Report.pdf).

competition other ES technologies is, more specifically with the fast growing Li-ion batteries that offer flexible alternatives for distributed storage applications.

Although PHS is an old and mature ES technology, many developments in engineering and design underway can further advance the technology: by expanding existing capabilities over a wider operating range, enabling new capabilities, and by enabling new geographical sites. One of its main advantages compared to competing technologies is its proven track record and reliability. If large amounts of energy and power are needed, then PHS surpasses all ES technologies. In contrast, its current lack of flexibility and modularity would prevent access to the DER market, if it comes to materialize. Finally, PHS serves a wide range of applications at lower price (< $150/kWh) compared to competing technologies. The main concern is the lack of suitable sites, especially with the conventional design. As such, exploring advanced designs may provide new opportunities.

Compressed air energy storage (CAES)

Compressed air energy storage is the only other commercial low cost technology, which is analogous to PHS and can generate power outputs in excess of 100 MW, in a single unit. Presently, there are only a few units in operation in the world totaling 450 MW in 2017.[72] However, several facilities are currently either under contract or under construction. Compressed air energy storage can serve many utility applications; such as frequency and voltage control, load shift, peak shaving, and black start services. In addition, it can also help integrate variable renewable power sources, and defer transmission and distribution level investments.

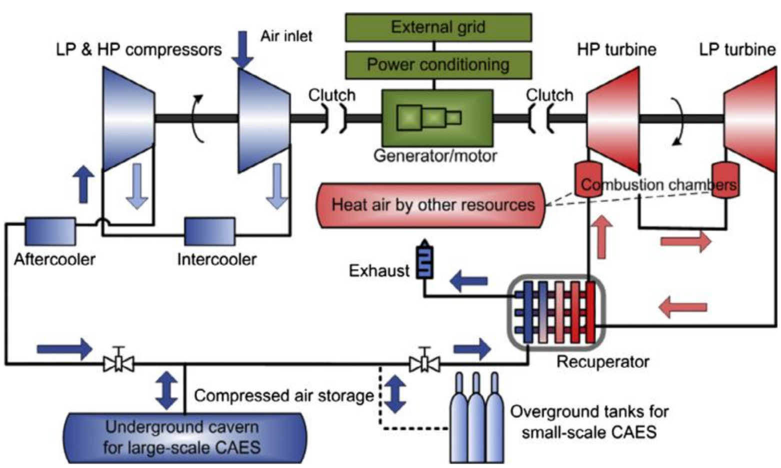

Figure 46: Schematic of a compressed air energy storage system.[73]

During storage (charge), off-peak power air is run though the compressors to be injected into a storage vessel (underground caverns, salt caverns, underground aquifers, or over ground tanks) until it reaches high pressure (Figure 46). The energy remains stored in the form of high-

[72] IRENA. 2017. "Electricity storage and renewables: Costs and markets to 2030." International Renewable Energy Agency, Abu Dhabi. (https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf).

[73] X. Luo, J. Wang, M. Dooner, and D. Clarke. 2015. "Overview of current development in electrical energy storage technologies and the application potential in power system operation." (*Applied Energy.* 137, 511-536, 2015).

pressure air. When power is needed (discharge), the stored compressed air is released, mixed with fuel (such as gas, oil, or hydrogen), combusted, and passed through a turbine. It then expands, releases energy, spins the turbine and produces electrical energy.

There exist two CAES system designs, the diabatic and adiabatic. The former is the only configuration that has been implemented so far. In this system described above, the heat generated during compression is dissipated in the atmosphere, while during expansion air needs to be reheated with fuel, lowering system efficiency. In contrast, in the emerging adiabatic design, the heat is compressed and expanded without the addition of fuel, improving system efficiency.[74]

Technology:

CAES technology has low energy density (2–6 Wh/L) as it requires large air vessels, and power densities range between 0.2 and 0.6 W/L. Energy is typically stored for 2 to 30 hours, and discharges last hours. Self-discharge is not significant, and response time is within minutes. CAES systems have long cycle life (> 10,000) and long lifetime (20–40 years). But system efficiency can be low (40–75%) depending on the configuration.[75, 76]

Environmental Impact:

Diabetic CAES plants emit GHG, although in low quantity relative to conventional gas turbines, equivalent to one-third their output. Newer plants have been able to reduce emissions by using exhaust gas to heat the air. Finally, in newer designs, the adiabatic and isothermal plants, the emissions are completely avoided.[77]

Case Studies:

There exist only two large-scale CAES plants currently in operation in the world. The first system was deployed in Huntorf, Germany, in 1978, while the second was installed in McIntosh, Alabama, in 1991 (Figure 39). These two installations have been operating succesfully since their installation.[78]

The 290 MW system in Germany stores the compressed air in two ""solution-mined"" salt caverns. One cavern is cycled on a diurnal basis, while the second serves as a black start asset in case the nearby nuclear power plant unexpectedly powers down.

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[74] K. Bradbury. 2010. *Energy storage technology review.* (August 2010. https://www.kylebradbury.org/docs/papers/Energy-Storage-Technology-Review-Kyle-Bradbury-2010.pdf).

[75] Schlumberger Business Consulting (SBC) Energy Institute. 2013. "Leading the Energy Transition, The Electricity Storage Factbook*."* (Presentation. September 2013. http://energystorage.org/system/files/resources/sbcenergyinstitute_electricitystoragefactbook.pdf).

[76] International Electrotechnical Commission (IEC). 2011."Electrical Energy Storage Whitepaper." (*IEC White Papers and Technology Reports*. https://www.iec.ch/whitepaper/energystorage/).

[77] Schlumberger Business Consulting (SBC) Energy Institute. 2013. "Leading the Energy Transition, The Electricity Storage Factbook*."* (Presentation. September 2013. http://energystorage.org/system/files/resources/sbcenergyinstitute_electricitystoragefactbook.pdf).

[78] A. A. Akhil, G. Huff, A. B. Currier, B. C. Kaun, D. M. Rastler, S. Bingqing Chen, A. L. Cotter, D. T. Bradshaw, and W. D. Gauntlett. 2014. "DOE/EPRI Electricity storage handbook in collaboration with NRECA." (Sandia Report, SAND2015-1002, September 2014; https://prod-ng.sandia.gov/techlib-noauth/access-control.cgi/2015/151002.pdf).

The 110 MW plant in Alabama also uses a solution-mined salt cavern. The cavern can discharge for 26 hours. The main application of this facility is peak shaving.

There are several in-ground CAES plants in contract or under construction, in Europe and in the United States.

Developments are under way to test other geological structures to overcome the constraints on site availability for CAES systems. Concrete lining tunnels, hard rock caverns, porous rocks, porous sandstone aquifers, are just a few examples of structures that have been tested. Above ground air storage would be of smaller size, with typical capacities in the 3 to 50 MW range, and discharge times of 3 to 5 hours. However costs would be higher than the in-ground installations.[79]

Adiabatic CAES is also attracting a lot of interest for its operation without any use of combustion fuel, improved efficiency, and lower environmental impact. The largest planned demonstration adiabatic CAES facility is a 290 MW project based in Germany called project ADELE. It is a consortium between German utilities RWE and GE, the German Aerospace Center DLR, construction company Zublin, the Fraunhofer IOSB and the University of Magdeburg. However, no demonstration plant has been completed successfully so far.[80]

CAES technology is commercial low cost, at approximately $200/kWh (Figure 43) but which is limited to the availability of suitable geological sites, analogous to pumped hydro. As such, unless such sites exist in New Jersey, CAES may not be an option. However, technological developments may on the long term alleviate site constraints, which may change the suitability of CAES technology over time.

Flywheel energy storage (FES)

While flywheels have existed for centuries, they have been considered as a form of bulk energy storage only in modern history. Flywheel energy storage (FES) is a commercial technology, which consists of a mass rotating within a frictionless container leading to kinetic energy storage. These systems have extremely rapid response times and high efficiency, but short storage times. As such, these FES systems are mainly used for power quality, regulation services, and back-up power supply.[81] By 2017, FES installations totaled 961 MW, globally.[82]

[79] A. A. Akhil, G. Huff, A. B. Currier, B. C. Kaun, D. M. Rastler, S. Bingqing Chen, A. L. Cotter, D. T. Bradshaw, and W. D. Gauntlett. 2014. "DOE/EPRI Electricity storage handbook in collaboration with NRECA." (Sandia Report, SAND2015-1002, September 2014; https://prod-ng.sandia.gov/techlib-noauth/access-control.cgi/2015/151002.pdf).

[80]Energy Storage Sense. CAES: A simple idea but a difficult practice. (http://energystoragesense.com/uncategorized/caes-a-simple-idea-but-a-difficult-practice/).

[81] A. A. Akhil, G. Huff, A. B. Currier, B. C. Kaun, D. M. Rastler, S. Bingqing Chen, A. L. Cotter, D. T. Bradshaw, and W. D. Gauntlett. 2014. "DOE/EPRI Electricity storage handbook in collaboration with NRECA." (Sandia Report, SAND2015-1002, September 2014; https://prod-ng.sandia.gov/techlib-noauth/access-control.cgi/2015/151002.pdf).

[82] Ran Fu, Timothy Remo, and Robert Margolis. 2018. *2018 U.S. Utility-Scale Photovoltaics-Plus- Energy Storage System Costs Benchmark*. (Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71714. https://www.nrel.gov/docs/fy19osti/71714.pdf).

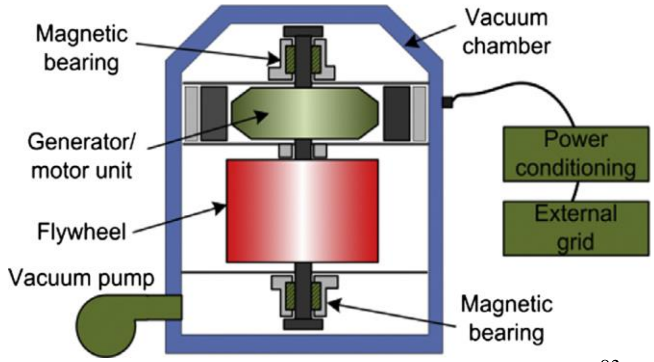

Figure 47: Schematic of a flywheel energy storage system.[83]

The flywheel is usually surrounded by a reversible generator and magnetic bearings, contained within a thick steel vessel for safety and performance (Figure 47). Placing the system under vacuum reduces energy losses through wind shear. During storage (charge), electricity is used to power a motor, which sets a rotor in motion, which keeps spinning at very high speed within the frictionless vessel, until the energy is needed. During discharge, the inertial energy of the rotor is used to drive a generator. Flywheel energy storage systems come in two variations, low (< 10,000 rpm) and high (>10,000) speeds.[84, 85]

Technology:

Flywheel energy storage technology is low specific density (5–30 Wh/kg), low energy density (20–80 Wh/L) and suffers from high self-discharges (up to 20% per day) during standby, as a result of frictional losses. However, FES technology has many beneficial characteristics. It has relatively high power density (5,000 W/L), high cycling efficiencies (80–90%), excellent cycle life (> 100,000 cycles) with no depth of charge impact, and long life (over 25 years) with easy maintenance. Flywheel devices respond very rapidly, within seconds, but they can only store energy for very short periods of times, seconds to minutes.[86, 87]

Environmental Impact:

The FES technology has little environmental impact, the systems are manufactured with benign and inert materials and they produce no emissions.

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[83] X. Luo, J. Wang, M. Dooner, and D. Clarke. 2015. "Overview of current development in electrical energy storage technologies and the application potential in power system operation." (*Applied Energy.* 137, 511-536, 2015).
[84] A. A. Akhil, G. Huff, A. B. Currier, B. C. Kaun, D. M. Rastler, S. Bingqing Chen, A. L. Cotter, D. T. Bradshaw, and W. D. Gauntlett. 2014. "DOE/EPRI Electricity storage handbook in collaboration with NRECA." (Sandia Report, SAND2015-1002, September 2014; https://prod-ng.sandia.gov/techlib-noauth/access-control.cgi/2015/151002.pdf).
[85] Schlumberger Business Consulting (SBC) Energy Institute. 2013. "Leading the Energy Transition, The Electricity Storage Factbook*."* (Presentation. September 2013. http://energystorage.org/system/files/resources/sbcenergyinstitute_electricitystoragefactbook.pdf).
[86] X. Luo, J. Wang, M. Dooner, and D. Clarke. 2015. "Overview of current development in electrical energy storage technologies and the application potential in power system operation." (*Applied Energy.* 137, 511-536, 2015).
[87] International Electrotechnical Commission (IEC). 2011."Electrical Energy Storage Whitepaper." (*IEC White Papers and Technology Reports*. https://www.iec.ch/whitepaper/energystorage/).

Case Studies:

Flywheel energy storage systems are flexible and modular; power and energy can essentially be decoupled. Power is based on the power conversion system, motor, and generator, while energy is dependent on the flywheel mass and speed.[88]

One of the largest FES systems, rated at 23 MW, has been developed and installed by Okinawa Electric Power Company and Toshiba, in Japan in 1985. The system serves for frequency control in the Okinawa power grid. By 2012, it had already accumulated over 10,000 charge-discharge cycles.[89]

In the United Stated, a 20 MW plant has been in operation since 2011in Stephentown, New York. Two hundred 100 kW/25 kWh flywheel devices, manufactured by Beacon Power, store a total of 5 MWh over 15 minutes, with an 85% round trip efficiency. The system responds within less than four seconds, and is also used for FR.

Other systems of smaller sizes have also already been deployed in the United States, aiming at improving power quality, either in regional transmission or local distribution siting. Smaller-scale customer-owned systems are also used for supply reserve and resiliency. [90]

In short, FES systems are flexible and scalable; as such it can meet the needs of the behind-the-meter market, as well as of the in front-of-meter market.

Electrical thermal energy storage (TES)

In 2017, thermal energy storage (TES) generated 3.3 GW globally, equivalent to 1.1% of total capacity, and 0.8 GW in the United Stated. Thermal energy storage is based on the concept of storing thermal energy upon heating or cooling a storage medium to be used at a later time for heating and cooling applications, and power generation. Thermal energy storage has become a strategic tool to help balance electric supply and demand, reduce peak demand, integrate variable renewable power sources, and enable customers optimize their EBM. As such, TES technologies could complement other types of ES to more efficiently serve many utility applications, and save costs.

There exist various types of TES systems, which can be classified based on operating temperatures, low versus high, and on the type of storage medium; sensible heat, latent heat and thermo-chemical storage. Sensible heat storage systems store energy upon heating or cooling a storage media. The most commonly and commercially used is low cost water. Hot water tank systems are cost effective solutions that store energy by heating water from solar energy or in co-generation (i.e., heat and power) and release on demand. Such systems are in use in residential,

[88] K. Bradbury. 2010. *Energy storage technology review.* (August 2010. https://www.kylebradbury.org/docs/papers/Energy-Storage-Technology-Review-Kyle-Bradbury-2010.pdf).
[89] IEA-ETSAP and IRENA. 2012. Electricity Storage. Technology Brief (April 2012. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2015/IRENA-ETSAP-Tech-Brief-E18-Electricity-Storage.pdf?la=en&hash=37013F61709E70A427C6AA5C72BC7137DF206B56).
[90] U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).

commercial, and residential sectors However, specific energies are low at 10–50 kWh/t, temperatures are variables during discharges, efficiencies can be low depending on the insulating system (50–90%).[91]

Sensible heat technologies, such as the molten salt and pumped TES, are based on molten salts and solid storage media, to exploit the benefits associated to larger temperature differentials, high heat capacity, high-density, and low vapor pressure, that provide higher performing systems.

Latent heat storage systems store energy using a medium, which changes phase at the operating temperature, such as the solid to liquid transformation. Such systems include ice thermal energy storage. Latent heat storage systems provide higher specific energies (50–150 kWh/t) relative to sensible heat (10–50 kWh/t).

Finally, thermo-chemical energy storage are high energy density (120–250 kWh/t) based on chemical reactions, such as adsorption, to store and release thermal energy.[92] Temperatures remain constant throughout the process. However, these systems are complex and expensive, and are not reviewed herein. Within the context of this report, only thermal systems which use electrical energy to heat or cool are considered to relevant.

Ice electrical energy storage

Ice thermal energy storage (TES) is a proven and mature technology to store cooling and shift electric load to off-peak hours. Energy is stored by freezing water during off-peak hours, and released when air-cooling is needed, usually during peak-hours. Ice TES conduces to EBM. During hot seasons, energy and demand charges are reduced, and total energy consumption is often lowered. Savings vary depending on utility rates.

Ice TES delivers benefits to regional transmission operators and local distribution system utilities by reducing peak load during hot season. Annual electricity demand peaks in the afternoon on the hottest days of the year, when air conditioners in homes and offices are powered on. It is a significant technical challenge for utilities and grid operators to meet such high demand. The additional capacity is sourced from power plants typically through contract for only a few hours a day, which is difficult to predict.[93]

Ice TES can also assist in the integration of renewable power sources. For instance, peak demand and PV output do not overlap perfectly since air conditioning tends to trail later in the

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[91] EA-ETSAP and IRENA. 2013. "Thermal energy storage. Technology brief." (January 2013. Accessed February 14, 2019. https://www.irena.org/DocumentDownloads/Publications/IRENA-ETSAP%20Tech%20Brief%20E17%20Thermal%20Energy%20Storage.pdf).
[92] EA-ETSAP and IRENA. 2013. "Thermal energy storage. Technology brief." (January 2013. Accessed February 14, 2019. https://www.irena.org/DocumentDownloads/Publications/IRENA-ETSAP%20Tech%20Brief%20E17%20Thermal%20Energy%20Storage.pdf).
[93] C. Roselund. 2019. "Ice Energy brings the deep freeze to U. S. energy storage." (*PV magazine*. February 13, 2019. Accessed May18, 2019.https://pv-magazine-usa.com/2019/02/13/ice-energy-brings-the-deep-freeze-to-u-s-energy-storage/)

day relative to the peak of PV output. As such, ice TES could help mitigate air conditioning demand after the sun goes down.[94]

Ice TES's working principle is illustrated in (Figure 48). A chilled water system (chiller) produces solid ice from a water/glycol-based coolant mixture that circulates through a tank and a heat exchanger. The glycol solution, which is always able to circulate through the ice, delivers the stored energy to the cooling coil on demand. Finally, a fan blows air over the coils to disperse the cooling air throughout the space.

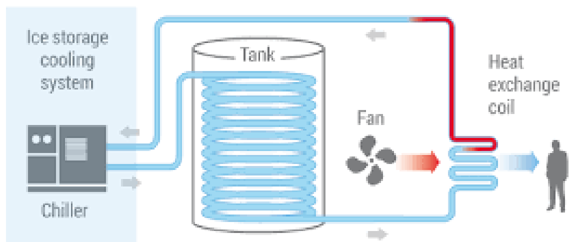

Figure 48: Schematic of an ice thermal energy storage system.[95]

Technology:

Ice TES is a latent heat technology based on melting processes involving energy densities on the order of 100 kWh/m^3, compared to 25 kWh/m^3 typically obtained with sensible heat systems.[96] Ice thermal energy storage systems shift load for typically 6 to 12 hours. They are low-maintenance and durable with over a 20-year lifetime.

Environmental Impact:

Ice TES systems are made of non-hazardous and non-flammable materials that can be recyclable. As such, the environmental impact is minimal.

Case Studies:

Ice TES technology is deployed globally. The systems configuration can vary, depending on the targeted market. Centralized systems target large-scale applications, such as district cooling systems, large industrial plants, combined heat and power plants, and renewable power plants. In contrast, distributed systems are mostly applied to smaller-scale domestic and commercial buildings.[97]

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[94] C. Roselund. 2019. "Ice Energy brings the deep freeze to U.S. energy storage." (pv mazine. February 13, 2019. Accessed May 17, 2019. https://pv-magazine-usa.com/2019/02/13/ice-energy-brings-the-deep-freeze-to-u-s-energy-storage/).
[95] Calmac. "How thermal energy storage works." (Calmac website accessed May 17, 2019. http://www.calmac.com/how-energy-storage-works).
[96] EA-ETSAP and IRENA. 2013. "Thermal energy storage. Technology brief." (January 2013.. https://www.irena.org/DocumentDownloads/Publications/IRENA-ETSAP%20Tech%20Brief%20E17%20Thermal%20Energy%20Storage.pdf).
[97] Navigant Research. 2018. "North American Annual Power Capacity Deployments of Commercial & Industrial Thermal Energy Storage Systems Expected to Near 70 MW in 2027." (Press Release. Accessed March 27, 2019.

The ice TES system manufacturer Calmac (Trane/Ingersoll Rand), founded in 1947 and based in Fair Lawn, New Jersey, has installed a total of 9.5 MW and over 70 MWh of projects in New Jersey, since 1988. Calmac specializes in centralized systems for large-scale institutional, commercial and industrial markets. Some examples include:

- West Long Branch School District: 150 kW/1.2 MWh
- McGinniss Middle School, Perth Amboy: 225 kW/1.8 MWh
- Perth Amboy High School: 300 kW/2.4 MWh
- Louis Brown Rutgers Athletic Center: 375 kW/3.0 MWh

Perth Amboy school district will be installing another 250 kW/2 MWh unit this summer.

To date, the primary value of in New Jersey is cost savings, based mainly on demand charge reduction (from utility and PJM). As mentioned above, driver for thermal adoption will vary significantly with demand charge rates. In addition, ice TES may be a low cost option, compared to alternative options, to address power limitations, such as for Rutgers Athletic Center installation. Ice TES costs amount to $310/kWh.

There is an opportunity for considerable growth for ice TES in the large-scale market in New Jersey. High demand charges, particularly in Northern New Jersey, where demand charges are the highest, combined to many industries, businesses, and institutions, could provide many opportunities.[98] As the behind-the-meter distributed energy storage market matures, residential customers in New Jersey may also seek low cost ice TES systems that can provide cost and energy savings. As such, there is also potential growth in this market sector in New Jersey.

Ice Energy, founded in 2003, manufactures Ice Bear for the residential, commercial and industrial sectors, but it also directly serves utility companies. In February 2019, it completed the first phase of its contract with the utility Southern California Edison (SCE) to deploy 1,200 systems of ice TES at businesses and industrial facilities across the SCE territory. The final project will amount to 25.6 MW and 130 MWh, at a 6h-rating. The first phase consisted in the fabrication of 100 units totaling 1.9 MW. Under the terms of this agreement, Ice Energy supplies and installs the systems free of charge to the property and business owners, while the utility SCE pays to operate the units to manage load shifting and meet peak demand.[99]

Ice Energy had previously entered other partnership agreements, mostly in California, including a five-year contract from Riverside Public Utilities to provide 5 MW of behind-the-meter ice TES units. Riverside Public Utilities' purpose is to help integrate its increasing reliance on renewable energy resources, while maintaining low energy costs for its customers.[100]

In 2017, Ice Energy and Genbright were awarded a $3 million-contract by the Massachusetts Department of Energy Resources (DOER) to provide over 200 residential behind-

https://www.navigantresearch.com/news-and-views/north-american-annual-power-capacity-deployments-of-commercial-industrial-thermal-energy-storage-sy).

[98] Calmac. Personal communications.

[99] C. Roselund. 2019. "Ice Energy brings the deep freeze to U.S. energy storage." (pv mazine. February 13, 2019. Accessed May 17, 2019. https://pv-magazine-usa.com/2019/02/13/ice-energy-brings-the-deep-freeze-to-u-s-energy-storage/).

[100] U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).

the-meter energy storage systems, totaling 1 MW, on the island of Nantucket.[101] Residents can then purchase the Ice Bear units from Ice Energy at a discounted price.[102]

Ice TES, through its penetration of the residential, institutional, commercial, and industrial markets, as well as its agreements with utilities, could become one of the strategic assets to a portfolio of ES technologies to meet the needs of the modern and future electric grid. Ice TES's negative aspects such as its inability to address other needs such as electrical resiliency, deployability, and FR, is balanced with core positive attributes of intrinsic safety and low cost relative to batteries.

Molten salt energy storage

Molten salt thermal energy storage (TES) is a commercial, low-cost, large-scale technology, which typically stores energy from heat generated from concentrating solar plants. However, such systems are not considered electrical energy storage as, in this case, the system operates as an energy conversion system. But developments are currently underway to determine a path towards electrical thermal storage.

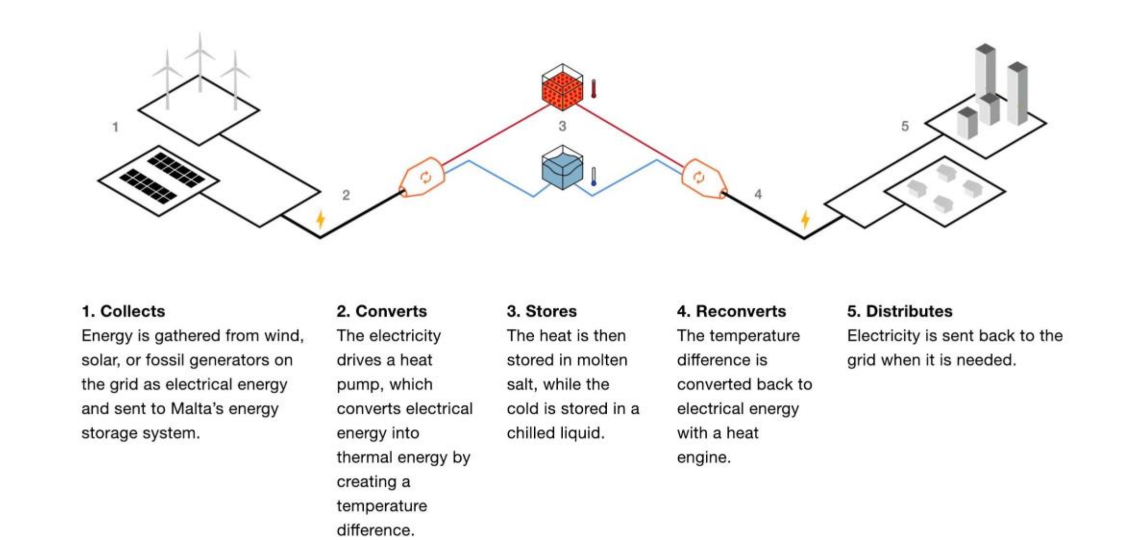

Figure 49: Working principle of Malta system based on molten salt energy storage.[103]

The molten salt system comprises two tanks. Molten salts are typically mixtures of 60% sodium nitrate and 40% potassium nitrate. Upon ES, the electrical energy gathered from the concentrating solar plant is directed to the 290°C cold tank, heats the molten salts that is sent to the hot tank at 570°C. During discharge, the hot salt it pumped through a superheater to a steam generator, producing steam that drives a turbine, producing electricity.

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[101] C. Ryan. 2017. "Ice Energy, Genbright to deploy 1MW of ice energy storage in Nantucket." (June 20, 2017. Accessed May 17, 2019. https://www.energy-storage.news/news/ice-energy-genbright-to-deploy-1mw-of-ice-energy-storage-in-nantucket).
[102] Ice Energy. Nantucket Program. (Accessed May 17, 2019. https://www.ice-energy.com/programs/nantucket/).
[103] S. Hanley. 2018. "Google X spins off Malta molten salt energy storage business." (*Clean Technica*. December 21, 2018. Accessed March 27, 2019. https://cleantechnica.com/2018/12/21/google-x-spins-off-malta-molten-salt-energy-storage-business/).

Technology:

Molten salt TES are centralized high power installation than can exceed 300 MW. The systems are able to store the energy for up to 15 hours and discharge times typically range between 7 to 10 hours, at high efficiency (80–90%). Response time is within minutes. However, molten salts should be maintained above freezing temperature to maintain good operation. Finally, systems lifetime is long (30 years).[104]

Environmental Impact:

Molten salts, typically a mixture of sodium nitrate and potassium nitrate, are non-flammable and non-toxic, but they can be corrosive, therefore they need to be disposed of accordingly.

Case Studies:

Molten salt TES is a commercial technology with proven benefits already demonstrated with the integrating of variable solar with concentrating solar plants. For instance, the SolarReserve's Crescent Dunes Solar Energy Facility, located in Tonopah, Nevada, was the first utility-scale molten salt TES facility to feature advanced molten salt power tower ES capabilities. Commissioned in 2015, the 110 MW-facility, coupled with ten hours of thermal storage generates total of 1,110 MWh of ES, is capable of powering 75,000 homes in Nevada during peak demand periods, day and night, whether or not the sun is shining.[105] In a path towards electrical to thermal storage, Google X has been developing a prototype system operating at lower temperatures while targeting suitable efficiencies and conventional low cost materials. The Malta prototype based on four vertical tanks using salts and antifreeze (Figure 49) was able to store energy for more than 6 hours and can be charged thousands of times before its performance begins to degrade, giving it an estimated service life of more than 20 years. The heat stored in the molten salt can be converted back to electricity on an as-needed basis at any time.[106] Emerging technologies may enable larger penetration of molten salt TES.

Pumped heat electrical energy storage

Pumped thermal energy storage (TES) is an emerging technology currently being developed to store energy. The energy can be delivered on demand, as either, or as a combination of high-grade heat, cryogenic thermal energy or electricity.[107] The concept is similar to that of pumped hydro storage, but instead of pumping water over a height differential, pumped thermal storage pumps heat over a temperature differential, where the storage material is a solid.

[104] Schlumberger Business Consulting (SBC) Energy Institute. 2013. "Leading the Energy Transition, The Electricity Storage Factbook." (Presentation. September 2013. http://energystorage.org/system/files/resources/sbcenergyinstitute_electricitystoragefactbook.pdf)
[105] U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).
[106] S. Hanley. 2018. " Google X spins off Malts molten salt energy storage business." (Clean Technica. December 21, 2018. Accessed March 27, 2019. https://cleantechnica.com/2018/12/21/google-x-spins-off-malta-molten-salt-energy-storage-business/).
[107] Sir Joseph Swan Center for Energy Research. National Facility for Pumped Heat Energy Storage. (Accessed May 19, 2019. http://www.isentropic.co.uk/).

Pumped TES can provide voltage regulation, supply reserve and participate in arbitrage at the transmission or distribution level.[108]

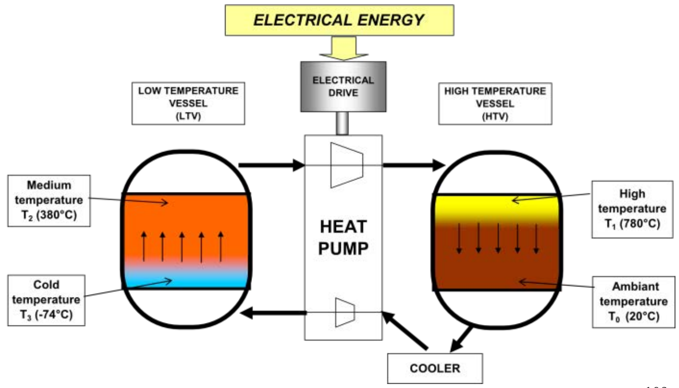

Figure 50: Schematic of a pumped thermal energy storage system.[109]

A pumped TES system consists of two tanks containing mineral gravel under inert atmosphere, typically argon (Figure 50). In storage mode (charge), the argon is compressed to 12 bar, heats to 500°C, enters the top of the "high temperature" tank, and flows down slowly. In the process, the particulate in the tank heat up and the argon cools down. As a result, the argon at the bottom of the tank is still at 12 bar, but is now at ambient temperature. At this point, it is expanded back to ambient pressure, and cools down to -106°C. It then enters the "low temperature" tank, cools the particulate at the bottom of the tank, and heats up, exits the tank at the top at ambient temperature and pressure (Figure 50).

To generate energy (discharge), the processes are reversed. Ambient argon enters the "low temperature" tank, cools, is compressed, and moves to the "high temperature" tank, heats to 500°C while maintaining its pressure. It only returns to ambient pressure in the expander that driver the generator and produces energy (Figure 50).[110]

Technology:

Pumped TES systems' ranges are 100 kW–200 MW in power and 500 kWh–1000 MWh in energy. Expected characteristics include 15–30 kWh/ton energy densities, 3–6 hour discharge times, high efficiencies (75–80%)[111], 1–2 second response time, long cycle life (> 15,000), and long lifespan (20–30 years).[112]

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[108] European Association for Storage of Energy. Energy Storage. Pumped Heat Electrical Storage. (Accessed May 19, 2019.http://ease-storage.eu/wp-content/uploads/2016/07/EASE_TD_Mechanical_PHES.pdf).
[109] Energy Storage Sense. "Energy storage technologies. Pumped thermal energy storage (PTES)" (Accessed May 17, 2019. http://energystoragesense.com/pumped-thermal-energy-storage-ptes/).
[110] The Engineer. 2019. "Newcastle University connects first grid-scale pumped head energy storage system." (January 9, 2019. Accessed May 19, 2019. https://www.theengineer.co.uk/grid-scale-pumped-heat-energy-storage/).
[111] The Engineer. 2019. "Newcastle University connects first grid-scale pumped head energy storage system." (January 9, 2019. Accessed May 19, 2019. https://www.theengineer.co.uk/grid-scale-pumped-heat-energy-storage/).
[112] European Association for Storage of Energy. Energy Storage. Pumped Heat Electrical Storage. (Accessed May 19, 2019. http://ease-storage.eu/wp-content/uploads/2016/07/EASE_TD_Mechanical_PHES.pdf).

Environmental Impact:

Pumped TES systems are made of non-hazardous and non-flammable materials that can be recyclable. As such, the environmental impact is minimal.

Case Studies:

Isentropic (United Kingdom) has received £15 million funding from the Energy Technology Institute to develop and build a pumped TES prototype. The team at the Sir Joseph Swan Center for Energy Research at Newcastle University has finalized the first 150 kW/600 kWhr grid-scale system that was designed, manufactured and installed on site. The team reported operation of the system in both expansion and compression modes, as well as switch between discharge and charge modes in a few milliseconds. Efficiencies have reached 60–65% efficiency, level consistent with the prototype design specification. Product development is expected to continue.[113]

This emerging technology based on low cost materials with no siting requirements and flexible power delivery options may be a strategic solution in the long term.

Electrochemical energy storage

In electrical electrochemical energy storage, electricity is stored in chemical form using electrons and ions as charge carriers. Various rechargeable batteries technologies have been utilized in grid applications. The rechargeable lithium-ion (Li-ion), lead-acid (Pb-acid), and nickel-cadmium (NiCd), and nickel metal hydride (NiMH) operate at ambient temperature. In contrast, the sodium sulfur (NaS) and sodium nickel chloride (so called “ZEBRA”) batteries operate at elevated temperatures above 270°C. Flow batteries and capacitors constitute additional types of energy storage that serve the large-scale utility market. The electrochemical energy storage technologies assessed over the span of this project are listed in Error! Reference source not found.

[113] The Engineer. 2019. “Newcastle University connects first grid-scale pumped head energy storage system.” (January 9, 2019. Accessed May 19, 2019. https://www.theengineer.co.uk/grid-scale-pumped-heat-energy-storage/).

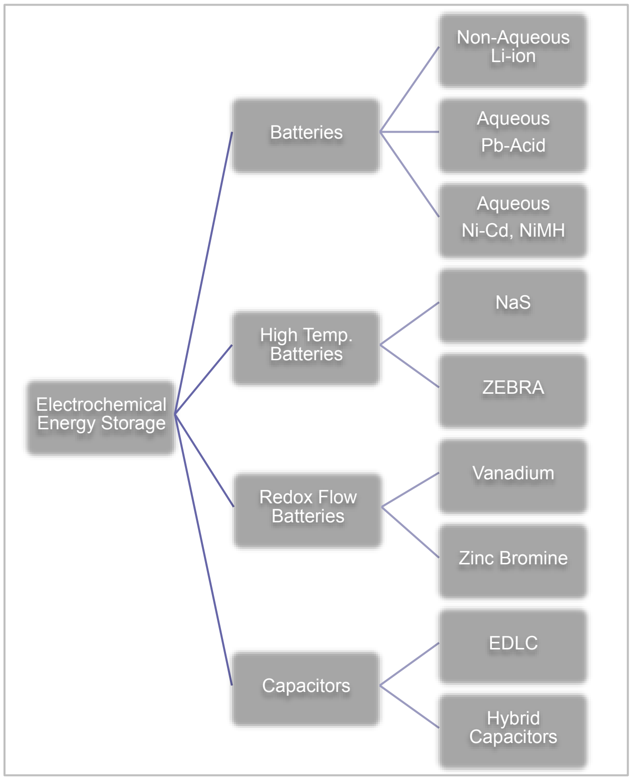

Figure 51: List of electrochemical energy storage technologies reviewed over the span of the project.

While electrochemical energy storage was marginally used for grid applications until 2011, since then many technologies have been successfully deployed and its market share has accelerated quickly and even grown exponentially since 2015 (Figure 52). Although still small in size at 1.9 GW globally and 680 MW in the United States,[114] the electrochemical energy storage market segment has become the most rapidly growing segment, stimulated by decreasing costs and improving performances and as such deserves thorough analysis. Although it is difficult to generalize the advantages of electrochemical energy storage, one quality factor, which defines this segment of energy storage is charge storage efficiency.

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[114] IRENA. 2017. "Electricity storage and renewables: Costs and markets to 2030." International Renewable Energy Agency, Abu Dhabi. (https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf).

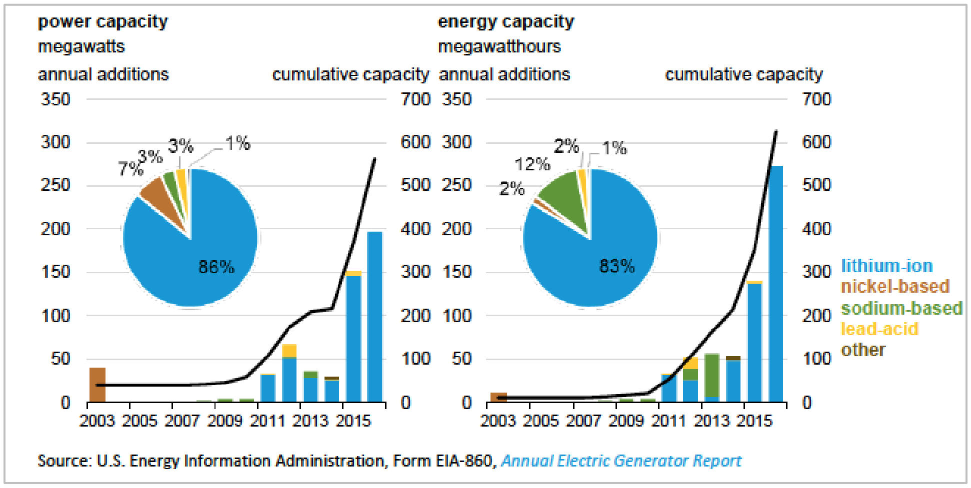

Figure 52: Electrochemical battery storage power (MW) and energy (MWh) in the United States between 2013 and 2016.[115]

Batteries

Regardless of their chemistries, the fundamental process involved in batteries is the transformation of chemical energy into electrical energy. This process is reversible in rechargeable secondary batteries, and if electricity is provided to the battery, the chemical energy is restored. A battery is composed of several cell in series and/or in parallel in order to provide the required application voltage and capacity. Battery characteristics, performance, and costs are highly dependent on chemistries as discussed below.

Lithium-ion (Li-ion) non aqueous batteries

Li-ion battery technology is the most rapidly growing ES market segment for grid applications in the past decade as illustrated in (Figure 52). The National Renewable Energy Laboratory (NREL) [116] reported in its "2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark" that the Li-ion ES capacity grew at a compound annual growth rate of 173 % in terms of cumulative capacity between 2008 and 2015. According to MacKenzie, Li-ion technology dominated the market with over 90 % of the MW capacity of the quarterly ES deployment at least since end of 2015 (Figure 52) and 97.5 % in Q3 of 2018. By mid-2017, Li-ion totaled approximately 1.1 GW globally amounting to 59 % of electrochemical energy storage operation installed capacity (Figure 52). In short, the implementation of Li-ion technology for grid-level applications over the past decade has been strong; stimulated by decreasing costs and improving performance.

[115] EIA. 2018. "U.S. Battery Storage Market Trends." (U.S. Energy Information Administration. www.eia.gov2018).
[116] Ran Fu, T. R., and Robert Margolis. 2018. U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark. (National Renewable Energy Laboratory. www.nrel.gov/publications).

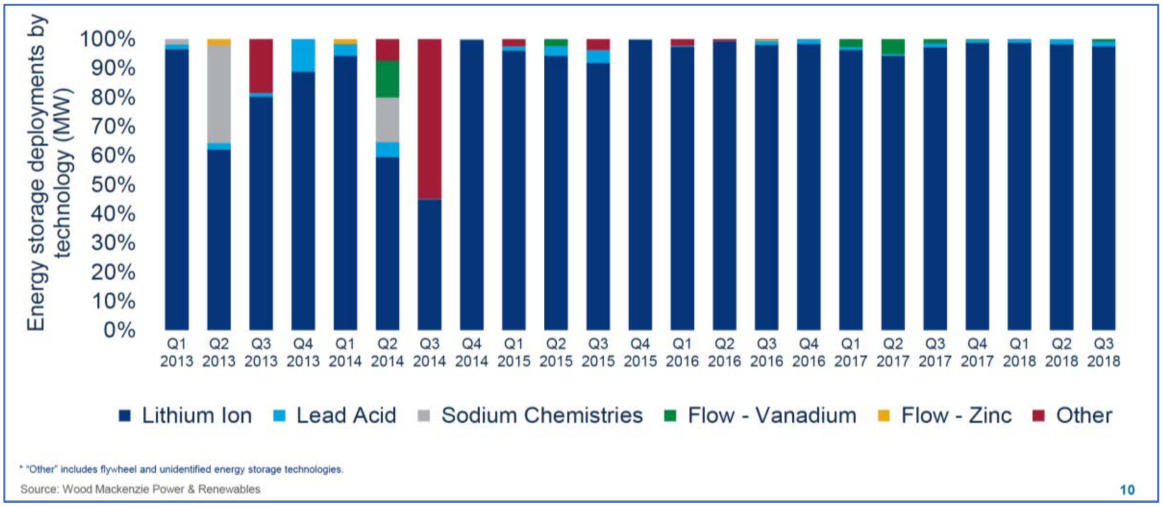

Figure 53: 2013-2018 quarterly energy storage deployment by technology, in percentage. [117]

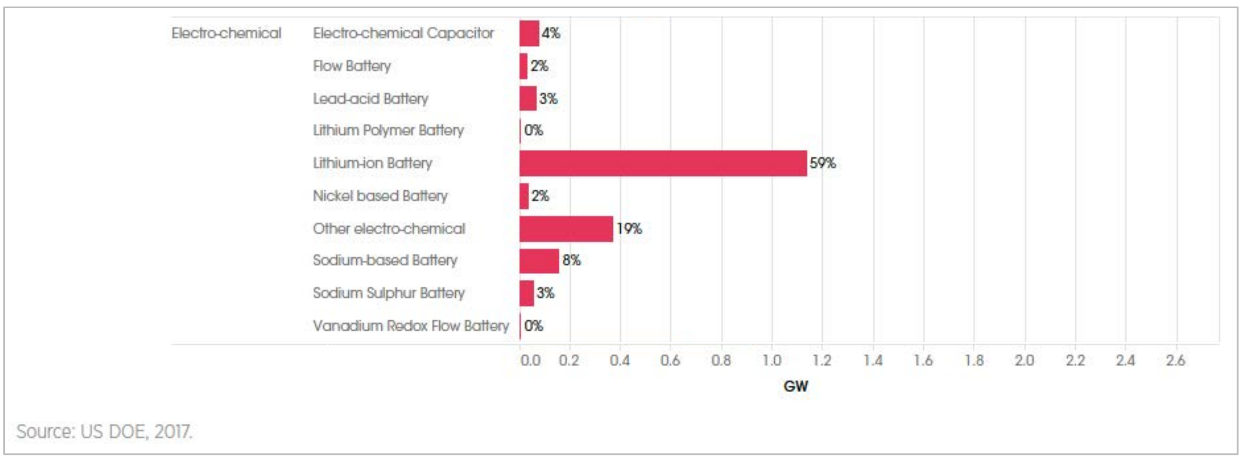

Figure 54: Breakdown of the electrochemical energy storage global power capacity in mid-2017. (adapted from[118]*)*

Present day Li-ion batteries consist of rechargeable devices based on intercalation electrodes, a carbon-based negative electrode and a lithium metal oxide positive electrode, exchanging Li^+-ions migrating through the electrolyte upon cycling (Figure 54). During charge, lithium ions are extracted from the positive electrode (or cathode) structure into the electrolyte. This process constitutes the chemical part of the reaction. Electrons are concurrently extracted from the positive electrode into the external electric circuit. Meanwhile, the reverse processes occur at the negative electrode (or anode). Lithium ions are inserted from the electrolyte into the negative structure while the external electric circuit supplies electrons. During discharge, all processes involved are reversed. The technology first commercialized by Sony in 1991 has since

[117] Dan Finn-Foley. 2019. "State of the U. S. Energy Storage Industry; 2018 and Trends to Watch." Wood Mackenzie Power & Renewables. (Prepared for the Energy Storage Technology Advancement Partnership (ESTAP) Webinar Series. Feb 28, 2019. https://www.cesa.org/webinars/state-of-the-u-s-energy-storage-industry-2018-year-in-review/).

[118] IRENA. 2017. "Electricity storage and renewables: Costs and markets to 2030." International Renewable Energy Agency, Abu Dhabi. (https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf).

grown to become ubiquitous, from personal electronics, to electric vehicles, space applications, and now also grid applications.

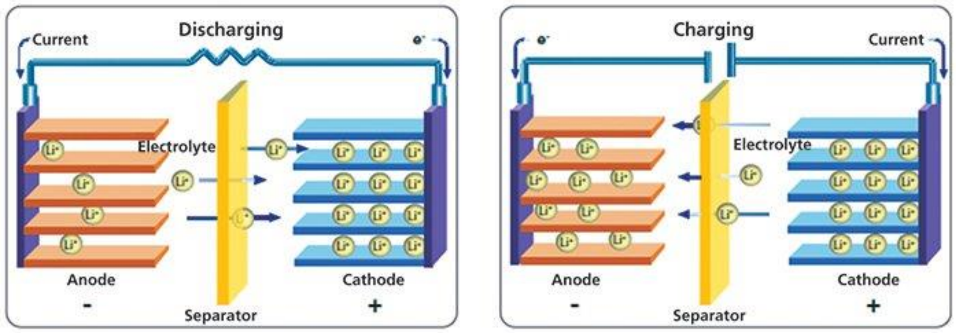

Figure 55: Schematics of a Li-ion battery showing the movements of Li-ions and electrons upon charge (right), and discharge (left).[119]

Chemistries:

A review of the different chemistries of the Li-ion technology and their implementation into energy storage systems for grid application is discussed in Appendix C – Element 3: Supporting Materials.

Technology:

Li-ion battery technology, through its rich chemistry, offers a wide range of grid-level ES system performance and cost characteristics. Li-ion batteries have good overall performance characteristics compared to competing technologies of today, including: high energy (70-270 Wh/kg and 200-700 Wh/L) and power densities (2000-10000 W/L), low self-discharge (0.05-0.2% per day), the highest round-trip efficiencies (>90%, DC-based and 85%, AC-based), relatively good cycle life (> 3000), good calendar life (> 10 years), and very short response time (millisecond). Li-ion battery technology offers advantageous properties over competing technologies, such as flexibility, scalability, and market versatility. However, safety concerns exist related to thermal stability, overcharge and internal pressure buildup, as well as intolerance to deep discharges,[120] which require additional thermal and battery management systems, and fire protection systems (see Figure 56) increase the installation footprint and cost.

[119] P. Voelker. 2014. "Trace Degradation Analysis of Li-ion Battery Components." (*R&D Magazine*. April 22, 2014. https://www.rdmag.com/article/2014/04/trace-degradation-analysis-lithium-ion-battery-components).
[120] U.S. Department of Energy. 2013. (*Grid Energy Storage 2013*. December 2013. https://www.energy.gov/sites/prod/files/2014/09/f18/Grid%20Energy%20Storage%20De cember%202013.pdf).

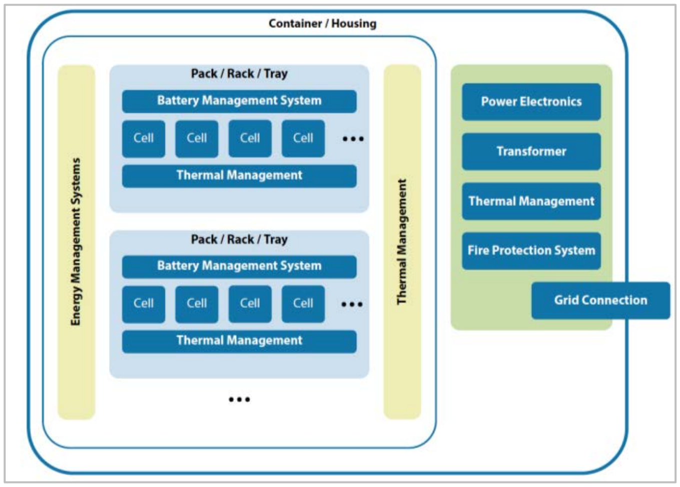

Figure 56: Schematics of battery storage systems and its various components. [121]

<u>Environmental Impact</u>

In order to minimize the environmental impact of the increasingly large number of Li-ion batteries bound to retire, it is well understood that adequate recycling protocols need to be developed in order to retrieve the valuable materials and safely dispose of the harmful substances. Many recycling processes aiming at recovering the metal valuables have already been developed, and some have even been industrialized. However, recycling processes are highly chemistry specific. As such, the diversity of the Li-ion battery chemistries and the constant evolution of the Li-ion technology make the development of recycling processes more challenging. Legislation to accelerate the standardization of the recycling process is also needed.[122]

Some companies have begun looking at the feasibility of using EV batteries that have gone beyond their useful lifetime for EVs for use as part of a large scale battery for utility applications. This is driven by the fact that many EV batteries are replaced when the battery still has considerable life, albeit at lower capacity, left in the battery pack. Some examples mentioned in the case studies below.

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[121] IRENA. 2017. "Electricity storage and renewables: Costs and markets to 2030." International Renewable Energy Agency, Abu Dhabi. (https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf).

[122] Bin Huang, Zhefei Pan, Xiangyu Su, and Liang An. 2018. "Recycling of lithium-ion batteries: Recent advances and perspectives." (*Journal of Power Sources*. 399 (2018): 274-286).

Case Studies:

By mid-2017, approximately 1.1 GW of Li-ion energy storage power capacity (IRENA[123]) – or up to 1.5 GW by the end of 2017 (NREL)[124] – was operational worldwide. While Li-ion market share increased rapidly, Li-ion technology has also advanced rapidly. The early Li-ion utility-system, Altairnano-PJM Lyons Li-ion Battery Ancillary Services Demo, deployed in 2008 in Lyons, Pennsylvania, was rated at 1MW in power and 0.25 MWh in energy ([77], Table 15). In contrast, the most extensive system in operation today achieved 100 MW and 129 MWh and was installed at the Hornsdale Power Reserve in Australia [6], resulting in an increase factor of 100 in rating within ten years. However, larger systems are already underway with the Vistra Moss Landing project in California ([1],Error! Reference source not found.**)** to be commissioned in 2020 to achieve a 300 MW/1200 MWh rating, an additional increase of over three times the rating of today's largest facility.

Li-ion's technical readiness, along with its highly scalable modular configuration, has enabled rapid scalability, leading to the drastic growth mentioned above. Indeed, two years after the 1 MW/0.25 MWh was commissioned in Pennsylvania, ABB installed a 20 MW/5 MWh system in Chile ([47], Table 13), while the AES Energy Storage deployed a 32 MW/8 MWh system in West Virginia ([20], Table 12**)** and was the largest Li-ion based systems when it started its operation in 2011 (Figure 57). Figure 57 shows how, in the case of the AES Laurel Mountain system, Li-ion batteries are arranged into modules, which themselves are assembled into trays that make up racks that are housed into cooled 2 MW containers thereby enabling scalability. Indeed, Li-ion and most battery configurations are flexible in configuration. The 100MW/129MWh system at the Hornsdale Power Reserve in Australia consists of Powerpacks from Tesla. The Powerpacks' ratings at 50 kW/210 kWh are quite small compared to the 2 MW AES Energy Storage containers at the Laurel Mountain facility. As such, the "Powerpacks farm" consists of about 645 Powerpacks (Figure 58), along with the required electronic, fire, and management systems. As such, installations can take different shapes and configurations to serve better the actual site and market they need to serve.

[123] IRENA. 2017. "Electricity storage and renewables: Costs and markets to 2030." International Renewable Energy Agency, Abu Dhabi. (https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf).

[124] Ran Fu, Timothy Remo, and Robert Margolis. 2018. *2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark*. (Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71714. https://www.nrel.gov/docs/fy19osti/71714.pdf.)

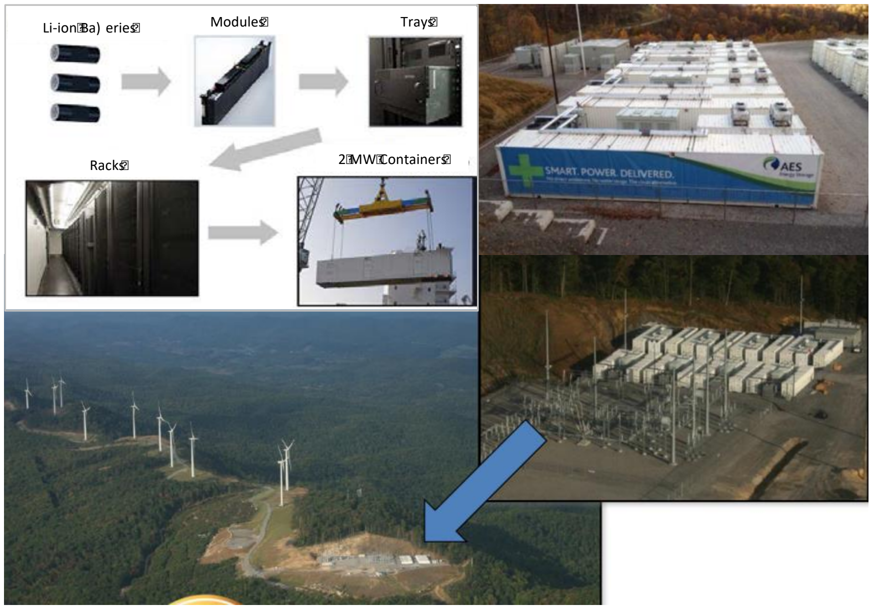


Figure 57: Li-ion battery system components,[125] pictures of the Laurel Mo*u*ntain s*i*te in West Virginia at various magnifications showing the 2 MW AES energy storage containers and localization (blue arrow) with respect to the 98 MW wind farm. [126]

The modularity of the Li-ion technology is especially critical to provide the DERs for an optimized grid. Energy system manufacturers continuously work on developing new and improved solutions to gain an edge over their competitors. A critical need that has been mentioned by several of New Jersey stakeholders is portability of the systems. Portability enables one to address transient needs, whether planned (i.e., maintenance, supplement for restricted transmission) or unplanned (i.e., resiliency). Standalone units exist with integrated power electronics, energy management systems, battery management systems, thermal management systems, and fire suppression systems. Several vendors, such as Fluence, Kokam, GE, and Hitachi, already offer such platforms, although configurations of the different components may vary within the container. These configurations are being pushed forward also significantly to decrease installation time and costs, and to improve flexibility. One step further to portability, Kokam already offers a "mobility energy storage system" as shown in Figure 58. Size, and therefore application, appear limited at the moment, requiring further development in portability.

[125] M. Bernardes. 2016. Armazenamento de energia: sistema de baterias de Lítio. (In *Tecnologia e Sustentabilidade*. http://blogs.pini.com.br/posts/tecnologia-sustentabilidade/armazenamento-de-energia-sistema-de-baterias-de-litio-371918-1.aspx).
[126] P. Kathpal. 2012. "Energy Storage: A Clean Capacity Alternative, AES Energy Storage." (Presented at NCSL Energy Supply Task Force, Denver, 2012).

Figure 58: Tesla 50 kW/ 201 kWh Powerpack-based energy storage system adjacent to the 315 MW wind farm of the Hornsdale Power Reserve, in Australia, owned and operated by French company Neoen. Picture obtained from [127].

The Li-ion based systems also provide flexibility in terms of duration times, as the size of the system can adjust them. Based on the 65 use cases of installation currently in operation of our survey in Table 12 through Table 15, the Li-ion energy systems in operation worldwide have an average rating of 23.3 MW in power, 20.9 MWh in capacity, and 1.06h (1h 4min) in duration time. In contrast, NREL reported in 2018 that utility-scale (> 1 MW) Li-ion systems in the United States averaged 9.9 MW in power and 17. 2 MWh in capacity with an average duration of 1.7h (Table 11). [128] The difference resides in the presence of international systems in our dataset with a similar outcome that shows a recent trend toward short duration time systems. Interestingly, California has most of the energy-oriented 4h-systems currently in operations in the United States. Also, the majority of the new systems coming online in California still consist of 4h-systems based on their intrinsic usefulness for enabling renewables and peak shifting applications versus frequency regulation.

Table 11: Li-ion energy storage in the United States by sector from 2008 to 2017. [129]

Sector	Total number of projects	Total kW	Total kWh	Average duration (hours)	Average system power rating (kW)	Average system energy (kWh)
Residential (< 10 kW)	18	116	278	2.4	6	15
Commercial (10–1,000 kW)	182	49,161	101,183	2.1	270	556
Utility-Scale (> 1,000 kW)	49	494,764	844,418	1.7	9,934	17,233
Total U.S.	**249**	**544,041**	**945,879**	**1.8**	**2,153**	**3,799**

[127] S. Alvarez. 2018. "Tesla's big battery in Australia is starting an energy storage movement." (*TeslaRati*. September 28, 2018. https://www.teslarati.com/tesla-powerpack-farm-australia-energy-storage-movement/).
[128] Ran Fu, Timothy Remo, and Robert Margolis. 2018. *2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark*. (Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71714. https://www.nrel.gov/docs/fy19osti/71714.pdf.)
[129] Ran Fu, Timothy Remo, and Robert Margolis. 2018. *2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark*. (Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71714. https://www.nrel.gov/docs/fy19osti/71714.pdf.)

Similarly, all of the surveyed installations, which recently came online and are coming online in Australia, are 4h-duration systems. It seems to show an upcoming trend towards longer systems. MacKenzie recently quoted that 4h-systems are becoming the norm for the front-of-the-meter market, while average behind-the-meter durations inch toward three hours.[130] As indicated in response to CEA Element 1, our analysis confirms similar results. However, installations' characteristics remain site and application specific, including such optimal duration to achieve the best benefits for all stakeholders.

Applications:

Li-ion batteries' favorable technical characteristics, such as short response time, excellent efficiency, combined to configuration flexibility, and scalability stemming from its modular design, open a wide range of potential opportunities across all the different market segments. Indeed, the Li-ion systems reviewed herein provide use case of ancillary, transmission, bulk energy, renewable integration, and customer services as shown in Table 12.

Li-ion energy storage systems are adequate for ancillary services and, more specifically, for those with duration times within 4h. Table 12 provides use cases for all ancillary services. Interestingly, frequency regulation is a market where Li-ion battery energy storage has become increasingly competitive as costs decreased. All of the power-oriented Li-ion systems reviewed participate in the FR market. Longer duration systems also participate as facilities "stack" services in order to increase revenue if the market structure allows it.

Li-ion technology is particularly well suited to enhance the integration of variable renewable energy resources. Li-ion energy storage could support local variable renewable energy generation in distribution networks, palliate grid congestion, and balance the power variable renewable energy in order to provide a stable and resilient grid. Table 12 lists Li-ion installations that currently provide ramping control, renewable energy time shift, and renewable capacity firming.

[130] Dan Finn-Foley. 2019. "State of the U. S. Energy Storage Industry; 2018 Year in Review and Trends to Watch." Wood Mackenzie Power & Renewables. (Prepared for the Energy Storage Technology Advancement Partnership (ESTAP) Webinar Series. Feb 28, 2019. https://www.cesa.org/webinars/state-of-the-u-s-energy-storage-industry-2018-year-in-review/).

Table 12: List of selected Li-ion battery storage systems with power ratings in the 31.5 to 300 MW range.

Ref.	Location	Project Name	Paired Grid Resource	Commiss.	Siting	Business Model	Power	Capacity	Duration	Ancillary Services					T. Services	Bulk Energy Services		Renewable Integration Services			Customer Services	
#				Year		Owner	MW	MWh	h:mm	FR	Electric Supply Reserve Cap.	Voltage Support	Black Start	Load Following	T. Congestion Relief	Electric Energy Time Shift	Electric Supply Cap.	Ramping	Renewable Energy Time Shift	Renewable Cap. Firming	Electric Bill Mgt	Resiliency
1	United States, CA, Moss Landing	Vistra Moss Landing Energy Storage Project	-	2020		Utility	300	1200	4:00			✓										
2	United States, CA, Moss Landing	Moss Landing Energy Storage Project		2020		Utility	182.5	730	4:00			✓										
3	United States, CA, Long Beach	Alamitos Energy Storage Array		2021		Third-Party	100	400	4:00								✓					
4	Australia, SA, Morgan	Riverland Solar Storage Project - Lyon Group	330 MW PV	N/A			100	400	4:00										✓	✓		
5	Australia, SA, Roxby Downs	Kingfisher Project	120 MW PV	2020		Third-Party	100	200	2:00										✓	✓		
6	Australia, SA, Horsndale	Hornsdale Power Reserve	315 MW Wind	2017		Utility	100	129	1:17	✓										✓		
7	United States, CA, Morgan Hill	Hummingbird Energy Storage Project		2020		Utility	75	300	4:00			✓										
8	United Kingdom	Roosecote Energy Storage		2018		Customer	49	24.5	0:30													
9	Germany	Jardelund "EnspireMe"		2016		Customer	48	50	1:02	✓						✓		✓	✓			
10	South Korea	Gyeongsan Substation		2016		Utility	48	12	0:15	✓		✓			✓							
11	Japan	Minami-Soma Substation	-	2016		Utility	40	40	1:00	✓		✓										
12	United Kingdom	Glassenbury Battery Storage Project		2017		Utility	40	28	0:41	✓												
13	Japan	Nishi-Sendai Substation	-	2016		Utility	40	20	0:30	✓		✓										
14	United States, TX, Goldsmith	Notrees Battery Storage Project (initially Pb-acid, Li-ion updgrate in 2016)	153 MW Wind	2013	T	Utility	36	24	0:40	✓						✓		✓				
15	South Korea	Non-Gong Substation	-	2016		Utility	36	13	0:22	✓												
16	United States, CA, Orange County	Convergent- SCE		2020		Utility	35	140	4:00								✓					
17	United Kingdom	Foresight Group Port of Tyne 35 MW ESS - RES (UK)		initially 2018		Customer	35	23	0:40	✓												
18	United States, CA, El Centro	Imperial Irrigation District (IID) BESS - GE	solar/geothermal /biomass/ hydro	2016	T	Customer	33	20	0:36	✓	✓		✓	✓				✓				
19	South Korea	Ul San Substation		2017		Utility	32	12	0:23	✓												
20	United States, W. VA, Elkins	AES Laurel Mountain Energy Storage	98 MW Wind	2011	T	Third-Party	32	8	0:15	✓								✓				
21	United States, W. VA, Rupert	Beech Ridge Wind Storage	100.5 MW Wind	2015		Third-Party	31.5	12.2	0:23	✓								✓				
22	United States, IL, Marseilles	Grand Ridge Energy Storage	210 MW Wind + 20 MW PV	2015		Third-Party	31.5	12.2	0:23	✓									✓			
			Contracted, Under construction						< 1h	1-2h	4h											

Table 13: List of selected Li-ion battery storage systems with power ratings in the 20 to 30 MW range.

"T" stands for Transmission, "Pri. D." stands for Primary Distribution and "Sec. D." stands for Secondary Distribution.

Ref.				Commiss.		Business Model	Power	Capacity	Duration	Ancillary Services					T. Services	Bulk Energy Services		Renewable Integration Services			Customer Services	
#	Location	Project Name	Paired Grid Resource	Year	Siting	Owner	MW	MWh	h:mm	FR	Electric Supply Reserve Cap.	Voltage Support	Black Start	Load Following	T. Congestion Relief	Electric Energy Time Shift	Electric Supply Cap.	Ramping	Renewable Energy Time Shift	Renewable Cap. Firming	Electric Bill Mgt	Resiliency
23	United States, CA, Escondito	Escondido Substation	Escondido Substation	2017	Pri. D	Utility	30	120	4:00	✓						✓			✓	✓		
24	Australia, VIC, Ballarat	Ballarat Area Terminal Station (BATS)		2018		Customer	30	30	1:00						✓					✓		
25	Australia	Newman Power Station - Alinta Energy	178 MW Gas Fired Plant	2018		Third-Party	30	11.4	0:23	✓		✓										
26	Australia, SA, Yorketown	Dalrymple		2018		Third-Party	30	8	0:16	✓		✓										✓
27	South Korea	West-Ansung (Seo-Anseong) Substation		2015		Utility	28	7	0:15	✓		✓			✓							
28	Australia, SA, Barmera	Lake Bonney Energy Storage	278.9 MW Wind	2019		Third-Party	25	52	2:05											✓		
29	Australia, VIC, Kerang	Gannawarra Energy Storage	60 MW PV	2018		Customer	25	50	2:00						✓					✓		
30	United States, AK, Anchorage	Anchorage Energy Storage		2016	T	Utility	25	14	0:34		✓			✓		✓						
31	United Kingdom	Enel S.p.A. Tynemouth		2018		Customer	25	12.5	0:30	✓												
32	South Korea	Shin-Yongin Substation		2014		Utility	24	12	0:30	✓		✓			✓							
33	South Korea	Shin-Gimje Substation		2016		Utility	24	9	0:23	✓		✓			✓							
34	South Korea	Uiryeong Substation		2016		Utility	24	6	0:15	✓		✓			✓							
35	South Korea	Shin-GyeRyong Substation		2016		Utility	24	6	0:15	✓		✓			✓							
36	United Kingdom	Pen y Cymoedd Storage	228 MW Wind (onshore)	2018			22	16	0:45	✓								✓				
37	Australia, QLD, Lakeland	Cape York 20 MW/80 MWh- 55 MW Solar PV- Lyon Group	55 MW PV	2019	T	Third-Party	20	80	4:00										✓	✓		✓
38	United States, CA, Pomona	Pomona Energy Storage Facility	44.5 MW Gas Fired Plant	2016	T	Third-Party	20	80	4:00								✓					
39	United States, CA, Ontario	Southern California Edison Mira Loma Substation		2017		Utility	20	80	4:00								✓					
40	Australia, VIC	Bulgana Green Energy Hub Victoria	194 MW Wind	2019		Third-Party	20	34	1:42								✓					
41	United Kingdom	Broxburn -RES		2018		Third-Party	20	22	1:06	✓												
42	United States, IN, Indianapolis	IPL Advancion Energy Storage Array - Harding St. Thermal Generation Plant	Thermal Power Plant	2016	T	Utility	20	20	1:00	✓												
43	United States, CA, Beacon	Beacon Battery Storage	570 MW PV + 490 MW PV expansion	2018		Utility	20	10	0:30	✓	✓			✓						✓		
44	United States, IL, DeKalb	Lee DeKalb Energy Storage	217.5 MW Wind	2015		Third-Party	20	10	0:30	✓												
45	United States, IL, Kern County	Marengo Project		2018		Third-Party	20	10	0:30	✓												
46	Chile	Cochrane Thermal Power Station Storage System	532 MW Coal-Hybrid Power Plant	2017	Pri. D	Third-Party	20	6.75	0:20							✓	✓					
47	Chile	AES Angamos Storage Array	544 MW Thermal Power Plant	2011	T	Third-Party	20	5	0:15	✓	✓											
			Contracted, Under construction						< 1h	1-2h	4h											

Table 14: List of selected Li-ion battery storage systems with power ratings in the 10 to 10.9 MW range.

Ref.				Commiss.		Business Model	Power	Capacity	Duration	Ancillary Services					T. Services	Bulk Energy Services		Renewable Integration Services			Customer Services	
#	Location	Project Name	Paired Grid Resource	Year	Siting	Owner	MW	MWh	h:mm	FR	Electric Supply Reserve Cap.	Voltage Support	Black Start	Load Following	T. Congestion Relief	Electric Energy Time Shift	Electric Supply Cap.	Ramping	Renewable Energy Time Shift	Renewable Cap. Firming	Electric Bill Mgt	Resiliency
48	United States, IL, McHenry County	McHenry Battery Storage Project		2015	Pri. D	Third-Party	19.8	7.8	0:24	✓							✓					
49	United States, IL Joliet	Jake Energy Storage		2015		Third-Party	19.8	7.8	0:24	✓												
50	United States, IL, West Chicago	Elwood Energy Storage Center		2015		Third-Party	19.8	7.8	0:24	✓												
51	United States, PA, Somerset County	Meyersdale Energy Storage		2015		Third-Party	18	9	0:30	✓												
52	United States, ME, Yarmouth	Wyman Station	822 MW Oil-fired Plant	2016			16.2	8.1	0:30	✓												
53	South Korea	Shin-ChungJu Substation		2016		Utility	16	6	0:23	✓		✓			✓							
54	Germany	Lünen Energy Storage	507 MW Co-generation Plant	2016		Utility	15	23	1:32	✓												
55	Germany	Walsum Energy Storage	560 MW Co-generation Plant	2016	T	Utility	15	23	1:32	✓												
56	Germany	Bexbach Energy Storage	780 MW Coal Power Plant	2016	T	Utility	15	23	1:32	✓												
57	Germany	Volklingen-Fenne Energy Storage	466 MW Co-generation Plant	2016	T	Utility	15	23	1:32	✓												
58	Germany	Weiher Energy Storage	724 MW Co-generation Plant	2016	T	Utility	15	23	1:32	✓												
59	Germany	Herne Energy Storage	960 MW Co-generation Plant	2016	T	Utility	15	23	1:32	✓												
60	Germany	Daimler AG 15 MWh		2016		Customer	15	15	1:00	✓												
61	Germany	WEMAG Schwerin Battery Park - Younicos		2014	Sec. D	Utility	15	15	1:00	✓		✓	✓									
62	United States, HI, Kaua'i	Kaua'i Dispatchable Solar Storage	12 MW PV	2017		Third-Party	13	52	4:00							✓			✓			
63	Germany	Daimler 2nd Life Storage - The Mobility House (Lünen (2))		2016		Third-Party	13	12.8	1:00	✓						✓					✓	
64	South Korea	GS E&R-LG Chem (Yeongyang)		2016		Customer	12.5	24	1:55											✓		
65	Chile	Los Andes Substation Battery Energy Storage		2009	T	Third-Party	12	4	0:20	✓	✓											
66	United States, HI, Kula	Auwahi Wind Farm Storage	21 MW Wind	2012		Third-Party	11	4.4	0:24									✓				
67	United States, PA, Somerset County	Green Mountain Energy Storage - NextEra		2015		Third-Party	10.4	10.4	1:00	✓										✓		
68	Germany	Feldheim Regional Regulating Power Station	72 MW Wind	2015		Third-Party	10	10	1:00	✓						✓				✓		
			Contracted, Under construction						< 1h	1-2h	4h											

Table 15: List of selected Li-ion battery storage systems with power ratings in the 1 to 8 MW range.

Ref.	Location	Project Name	Paired Grid Resource	Commiss.	Siting	Business Model	Power	Capacity	Duration	Ancillary Services					T. Services	Bulk Energy Services		Renewable Integration Services			Customer Services	
#				Year		Owner	MW	MWh	h:mm	FR	Electric Supply Reserve Cap.	Voltage Support	Black Start	Load Following	T. Congestion Relief	Electric Energy Time Shift	Electric Supply Cap.	Ramping	Renewable Energy Time Shift	Renewable Cap. Firming	Electric Bill Mgt	Resiliency
68	Germany	Feldheim Regional Regulating Power Station	72 MW Wind	2015		Third-Party	10	10	1:00	✓						✓				✓		
69	United States, CA, Techapi	Tehachapi Wind Energy Storage Project - Southern California Edison	4500 MW Wind	2014	T	Utility	8	32	4:00	✓	✓	✓			✓		✓			✓		
70	United States, CA, El Cajon	El Cajon Storage		2017	Pri. D	Utility	7.5	30	4:00							✓	✓		✓	✓		
71	United States, HI, Anahola	Kauai Island Utility Cooperative & REC Solar	12 MW PV	2015	Pri. D	Utility	6	4.63	0:46	✓		✓								✓		
72	Autralia, WA, Kalbarri	Kalbarri Microgrid Energy Storage	PV, Wind	2019		Utility	5	2	0:24	✓		✓										
73	United States, WA, Glacier	Glacier Battery Storage		2016	T	Utility	2	4.4	2:12													✓
74	United States, NJ,Atlantic City	ACUA Treatment Plant - Viridity Energy	7.5 MW Wind + 500 kW PV	2018		Customer	1	1.05	1:05	✓									✓	✓		✓
75	United States, NJ, Pennington	Hopewell Valley High School *Pilot program*	876 kWPV (rooftop)	2015		Utility	1	0.5	0:30	✓									✓	✓		
76	United States, TX, Luccock	Center For Commercialization of Electric Technology (CCET)		2013	T	Utility	1	1	1:00	✓	✓	✓						✓		✓		
77	United States, PA, Lyons	Altairnano-PJM Lyons Li-ion Battery Ancillary Services Demo		2008		Third-Party-Owned	1	0.25	0:15	✓									✓			
			Contracted, Under construction						< 1h	1-2h	4h											

Li-ion technology also participates in the transmission infrastructure market segment that includes transmission congestion relief and transmission upgrade deferral. However, none of the Li-ion systems in the use case list of Table 12 through Table 15 provides any transmission upgrade deferral service. Upgrade deferrals require from 1h to 8h-discharge range as such longer duration systems such as hydro may be more cost effective compared to Li-ion if all other parameters such as location requirements are met.

Several use cases of bulk energy services are listed in Table 12 through Table 15, including both electric energy time shift and electric supply capacity market segments. The main benefit of the Li-ion technology over the more traditional technologies, such as hydro-pumped and compressed air energy storages, is its flexibility so that its systems can be installed locally, wherever it is more convenient within the grid network.

Finally, customer energy management services are related to the use of ES to enhance customer's power quality and reliability, resiliency, and EBM located downstream from the ES location. A few use cases of Table 12 through Table 15 report the use of their Li-ion energy storage system for resiliency. The Daimler 2nd Life Storage system ([63], Table 14) is an example of behind-the-meter installation that participates in EBM. Li-ion energy storage systems are very well adapted for behind-the-meter applications in the residential, commercial, and industrial sectors. Many relatively small, scalable systems (Tesla, LG Chem., Sonnen, Varta, BYD, Sony) already have islanding capability so that they can become the source of power during grid outages, and they can last long periods of times, especially when paired with a variable renewable energy resource.

Costs:

Decreasing costs have also contributed to the rapid Li-ion market growth observed in the past decade. Figure 59 illustrates the Li-ion systems cost and price structures of stationary battery storage.[131] For system costs, in addition to the battery pack costs, one has to consider all additional components. Indeed, for large systems, battery cells only make up 35% of large-scale systems' costs (Figure 60)[132] as one needs to consider the balance of system (BOS), the power of conversion system (PCS) and engineering, procurement, and construction (EPC). Finally, to obtain full price other developer costs, overheads, and margins also apply. These site-specific costs may be quite high in New Jersey and may likely trend the cost of such systems to the higher end of the spectrum. As such, modular systems which have as much of the design and engineering, fabrication, and integration completed by the manufacturer before delivery may be an attractive route for New Jersey installations especially if the systems can be installed vertically in a stacked arrangement. Li-ion battery pack costs have been consistently decreasing

[131] I. Tsiropoulos, D. Tarvydas, and N. Lebedeva. 2018. *Li-ion batteries for mobility and stationary storage applications – Scenarios for costs and market growth*. EUR 29440 EN. (Publications Office of the European Union, Luxembourg, 2018, ISBN 978-92-79-97254-6, doi:10.2760/87175, JRC113360).
[132] IRENA. 2017. "Electricity storage and renewables: Costs and markets to 2030." International Renewable Energy Agency, Abu Dhabi. (https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf).

thanks to a parallel adoption by the EV market as illustrated in Figure 61.[133] Figure 62, which shows Li-ion battery stationary system costs for 2016 and 2017, also demonstrates the same spread in reported cost values for the renowned sources listed, indicating that the cost is design and project-specific, making a generalization difficult.[134]

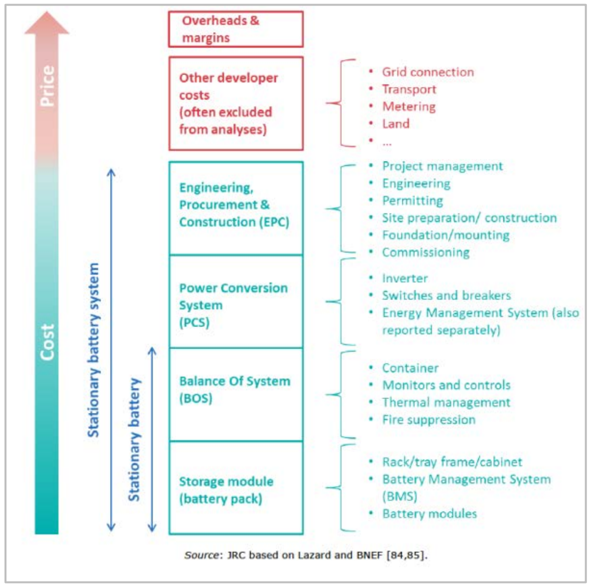


Figure 59: Illustrative system cost and price structure of stationary battery storage.[135]

[133] Dan Finn-Foley. 2019. "State of the U. S. Energy Storage Industry; 2018 Year in Review and Trends to Watch." Wood Mackenzie Power & Renewables. (Prepared for the Energy Storage Technology Advancement Partnership (ESTAP) Webinar Series. Feb 28, 2019. https://www.cesa.org/webinars/state-of-the-u-s-energy-storage-industry-2018-year-in-review/).

[134] I. Tsiropoulos, D. Tarvydas, and N. Lebedeva. 2018. *Li-ion batteries for mobility and stationary storage applications – Scenarios for costs and market growth*. EUR 29440 EN. (Publications Office of the European Union, Luxembourg, 2018, ISBN 978-92-79-97254-6, doi:10.2760/87175, JRC113360).

[135] I. Tsiropoulos, D. Tarvydas, and N. Lebedeva. 2018. *Li-ion batteries for mobility and stationary storage applications – Scenarios for costs and market growth*. EUR 29440 EN. (Publications Office of the European Union, Luxembourg, 2018, ISBN 978-92-79-97254-6, doi:10.2760/87175, JRC113360).

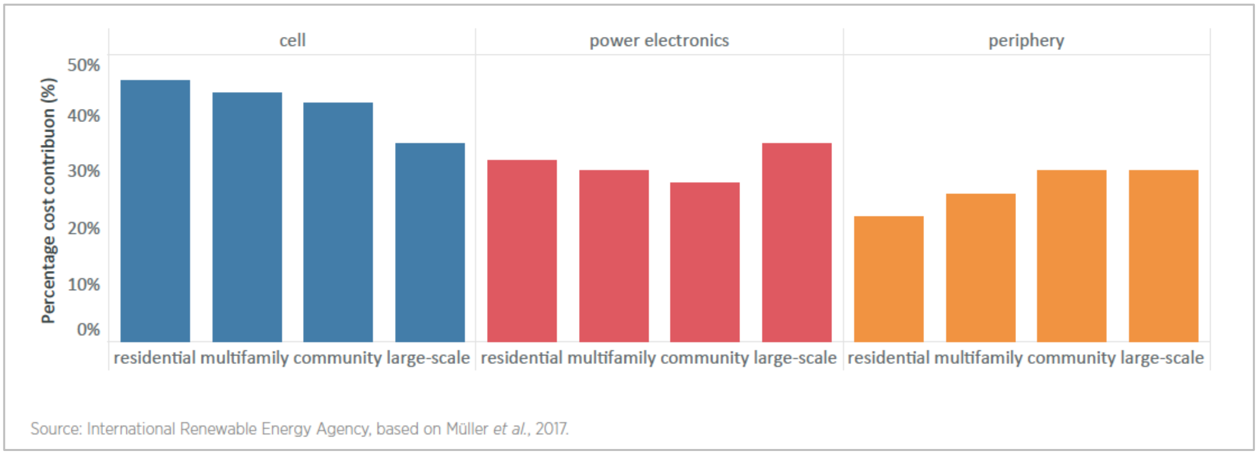


Figure 60: Cost component distribution of Li-ion battery energy storage systems for different storage sizes, 2016.[136]

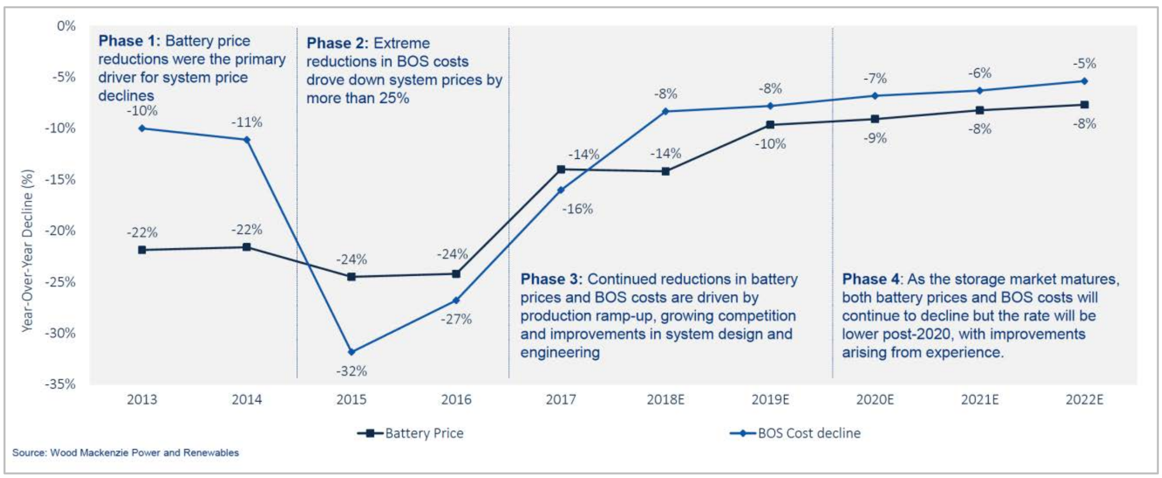


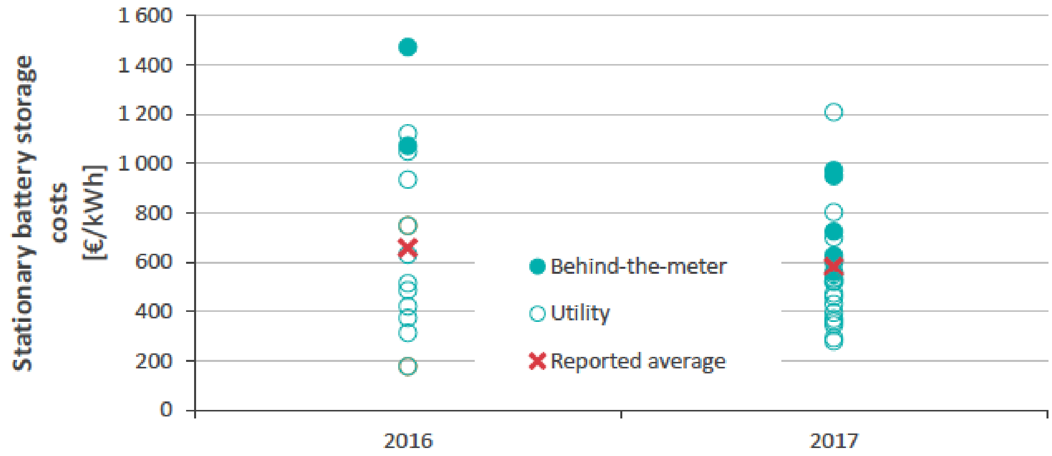
Figure 61: Year-over-year decline price and balance of system cost over 2013 to 2022 expressed in percentage.[137]

As such, we have provided in Table 16 a review of the CapEx costs for twenty-five of the installations we have surveyed to have specific costs correlated to *actual* use cases for benchmarking purposes. For the installations commissioned in the 2016-2018 period, on average, < 1h-systems cost $1,156/kW or $2,704/kWh, 1-2h-systems cost $1,996/kW or $1,154/kWh, and 4h-systems cost $2,563/kW or $641/kWh. Costs per unit of power (i.e., $/kW) decrease as duration time decrease, while costs per unit of energy (i.e., $/kWh) decrease as duration time increase. Our results were similar to those generated in 2017 by the US Energy Information Administration (EIA)[138] whose costs were slightly lower, possibly because they based their values on installations smaller than 14 MW and 17 MWh.

[136] IRENA. 2017. "Electricity storage and renewables: Costs and markets to 2030." International Renewable Energy Agency, Abu Dhabi. (https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf).
[137] Dan Finn-Foley. 2019. "State of the U. S. Energy Storage Industry; 2018 Year in Review and Trends to Watch." Wood Mackenzie Power & Renewables. (Prepared for the Energy Storage Technology Advancement Partnership (ESTAP) Webinar Series. Feb 28, 2019. https://www.cesa.org/webinars/state-of-the-u-s-energy-storage-industry-2018-year-in-review/).
[138] EIA. 2018. "U.S. Battery Storage Market Trends." (U.S. Energy Information Administration. www.eia.gov2018).

Table 16: List of capital expenditure for Li-ion battery storage systems.
*Notes: * indicates the conversion from € 100,000,000 for the 90 MW German installation, 6 x 15 MW (systems [54, 59]) using IRS average rate for 2016, ^ indicates the conversion from € 12,800,000 using IRS average rate for 2016 for installation [68], " indicates that a value of $42,500,000 was entered for system [38] whose installation cost estimation was reported in the $40,000,000-45,000,000 range [7]*

Ref.	Location	Project Name	Paired Grid Resource	Commiss.	Siting	Business Model	Tech	Power	Capacity	Duration	Capital Expenditure (CAPEX)	CAPEX /kW	CAPEX /kWh
#				Year		Owner	Chem.	MW	MWh	h:mm	$	$/kW	$/kWh
4	Australia, SA, Morgan	Riverland Solar Storage Project Lyon Group	330 MW PV	N/A			Li-Ion	100	400	4:00	300,000,000	3,000	750
5	Australia, SA, Roxby Downs	Kingfisher Project	120 MW PV	2020		Third-Party	Li-Ion	100	200	2:00	150,000,000	3,000	750
18	United States, CA, El Centro	Imperial Irrigation District (IID) BESS GE	solar/geothermal /biomass/ hydro	2016	Transmission	Customer	Li-Ion	33	20	0:36	35,000,000	1,061	1,750
20	United States, W. VA, Elkins	AES Laurel Mountain Energy Storage	98 MW Wind	2011	Transmission	Third-Party	Li-Ion (LFP)	32	8	0:15	29,000,000	906	1,450
24	Australia, VIC, Ballarat	Ballarat Area Terminal Station (BATS)		2018		Customer	Li-Ion	30	30	1:00	38,600,000	1,287	1,287
25	Australia	Newman Power Station Alinta Energy	178 MW Gas Fired Plant	2018		Third-Party	Li-Ion (NMC)	30	11.4	0:23	45,000,000	1,500	3,947
26	Australia, SA, Yorketown	Dalrymple		2018		Third-Party	Li-Ion	30	8	0:16	30,000,000	1,000	3,750
28	Australia, SA, Barmera	Lake Bonney Energy Storage	278.9 MW Wind	2019		Third-Party		25	52	2:05	38,000,000	1,520	731
29	Australia, VIC, Kerang	Gannawarra Energy Storage	60 MW PV	2018		Customer	Li-Ion	25	50	2:00	34,700,000	1,388	694
30	United States, AK, Anchorage	Anchorage Energy Storage		2016	Transmission	Utility		25	14	0:34	30,200,000	1,208	2,157
38	United States, CA, Pomona	Pomona Energy Storage Facility	44.5 MW Gas Fired Plant	2016	Transmission	Third-Party	Li-Ion	20	80	4:00	42,500,000"	2,125	531
42	United States, IN, Indianapolis	IPL Advancion Energy Storage Array Harding St. Thermal Generation Plant	Thermal Power Plant	2016	Transmission	Utility	Li-Ion	20	20	1:00	26,000,000	1,300	1,300
43	United States, CA, Beacon	Beacon Battery Storage	570 MW PV + 490 MW PV expansion	2018		Utility	Li-Ion	20	10	0:30	19,200,000	960	1,920
45	United States, IL, Kern County	Marengo Project		2018		Third-Party	Li-Ion	20	10	0:30	20,000,000	1,000	2,000
48	United States, IL, McHenry County	McHenry Battery Storage Project		2015	Primary Distribution	Third-Party	Li-Ion	19.8	7.8	0:24	20,000,000	1,010	2,564
49	United States, IL Joliet	Jake Energy Storage		2015		Third-Party	Li-Ion (LFP)	19.8	7.8	0:24	20,000,000	1,010	2,564
50	United States, IL, West Chicago	Elwood Energy Storage Center		2015		Third-Party	Li-Ion (LFP)	19.8	7.8	0:24	20,000,000	1,010	2,564
54	Germany	Lünen Energy Storage	507 MW Co-generation Plant	2016		Utility	Li-Ion	15	23	1:32	106,382,979*	1,182	925
55	Germany	Walsum Energy Storage	560 MW Co-generation Plant	2016	Transmission	Utility	Li-Ion	15	23	1:32			
56	Germany	Bexbach Energy Storage	780 MW Coal Power Plant	2016	Transmission	Utility	Li-Ion	15	23	1:32			
57	Germany	Volklingen-Fenne Energy Storage	466 MW Co-generation Plant	2016	Transmission	Utility	Li-Ion	15	23	1:32			
58	Germany	Weiher Energy Storage	724 MW Co-generation Plant	2016	Transmission	Utility	Li-Ion	15	23	1:32			
59	Germany	Herne Energy Storage	960 MW Co-generation Plant	2016	Transmission	Utility	Li-Ion	15	23	1:32			
68	Germany	Feldheim Regional Regulating Power Station	72 MW Wind	2015		Third-Party	Li-Ion	10	10	1:00	13,617,021^	1,362	1,362
69	United States, CA, Techapi	Tehachapi Wind Energy Storage Project Southern California Edison	4500 MW Wind	2014	Transmission	Utility	Li-Ion	8	32	4:00	50,000,000	6,250	1,563
71	United States, HI, Anahola	Kauai Island Utility Cooperative & REC Solar	12 MW PV	2015	Primary Distribution	Utility	Li-Ion (NCA)	6	4.63	0:46	7,000,000	1,167	1,512
72	Autralia, WA, Kalbarri	Kalbarri Microgrid Energy Storage	PV, Wind	2019		Utility	Li-Ion	5	2	0:24	6,800,000	1,360	3,400
73	United States, WA, Glacier	Glacier Battery Storage		2016	Transmission	Utility	Li-Ion	2	4.4	2:12	9,800,000	4,900	2,227
74	United States, NJ, Atlantic City	ACUA Treatment Plant Viridity Energy	7.5 MW Wind + 500 kW PV	2018		Customer	Li-Ion	1	1.05	1:05	1,390,320	1,390	1,324
76	United States, TX, Luccock	Center For Commercialization of Electric Technology (CCET)		2013	Transmission	Utility	Li-Ion (LMO)	1	1	1:00	2,000,000	2,000	2,000
			Contracted, Under construction							<1h	1-2hrs	4h	



Source: JRC based on Schmidt et al. [57], BNEF [85], IRENA [83], IEA [63], Deutsche Bank [65], Lazard [84] McKinsey [86] and Navigant [87].

Figure 62: Li-ion battery stationary system cost in 2016 and 2017 in €/kWh.[139]

While Li-ion systems' costs have been decreasing, Li-ion systems' costs remain high compared to some competing technologies. One must consider a reduction of all costs involved in the system installation as the Li-ion battery cell is not the dominant cost in almost all large-scale applications. Aggregation of the different elements of the battery systems into containers enabling pre-assembly constitutes one of the major approaches to cut costs further. Cutting installation costs, including labor costs is critical for New Jersey. Such an approach is critical as a decrease of Li-ion battery prices and BOS cost reductions are estimated to be slowing down (see Figure 61).

Implementation in New Jersey

Finally, focusing on the state of New Jersey, only a small number of Li-ion batteries have been deployed so far. As part of its Solar 4 All® Pilot Program, PSE&G deployed three Li-ion based systems that support the facilities paired with solar and maintain resiliency loads during prolonged power outages, and, upon restoration of power, operation automatically returns to the Normal Operation mode.[140] The 1 MW/0.5 MWh Hopewell Valley High School Pilot system ([75], Table 15) commissioned in 2015 serves as a community warming/cooling place for the public during an extended power outage. The 400 kW/200 kWh Cooper University Hospital system in service since 2016 operates refrigerators for vital pediatric medicines in case of emergency. The 574 kWh Tesla system at the Department of Public Works (DPW) in the

[139] I. Tsiropoulos, D. Tarvydas, N. Lebedeva. 2018. *Li-ion batteries for mobility and stationary storage applications – Scenarios for costs and market growth*. EUR 29440 EN. (Publications Office of the European Union, Luxembourg, 2018, ISBN 978-92-79-97254-6, doi:10.2760/87175, JRC113360).

[140] PSE&G. 2018. "PSE&G Solar 4 All® - Pilot Program, Grid Security / Storm Preparedness."PSE&G. (PowerPoint presentation. https://www.pjm.com/-/media/committees-groups/subcommittees/ders/20180326/20180326-item-05-pseg-solar-4-all-example.ashx).

Borough of Pennington has been in service since 2018 to help keep the building operational during an extended power outage.[141] While the main focus of the Solar 4 All® Pilot Program was to deploy large-scale grid connected solar in New Jersey, enabled by loans to PSE&G and authorized by NJ BPU,[142] it enabled critical pilot programs, such as those that focused on the integration of various ES with solar as described herein. However, the Solar 4 All® Pilot Program is still limited in scope and size. A 2 MW system is also noted to exist in Somerset County, and we are still currently working with PSE&G to acquire more information to determine its function within the network.

In 2014, 22 entities applied to the FY2015 NJCEP Renewable Electric Storage Incentive Solicitation. Projects maximized their score based on three main criteria: 1) resiliency by locating a public and critical facility, 2) technical feasibility by using demonstrated technologies, and 3) financials by being net metered, potentially reducing demand charges and participating in the PJM frequency regulation (FR) market. The only one out of the thirteen applicants awarded incentives and that completed a project was Viridity Energy, which built a 1 MW/1.05 MWh Li-ion based system at the Atlantic City Utility Authority (ACUA) wastewater treatment plant ([74], Table 15) on the Atlantic City Electric (ACE) network. According to the NJ BPU Order Docket No 001502023, the ACUA applicant was awarded an incentive of $417, 096 for a $1,390,320 project cost. This case clearly illustrates that incentives or costs are not the only issues or the main issue preventing the implementation of ES in New Jersey. Regulation issues with the utilities and PJM are significant factors. Indeed, in this case, the PJM change in regulation preventing behind-the-meter systems from participating in the FR market led twelve of the projects to relinquish their awards.[143] The ACUA project was reconfigured to be both behind- and in-front-of-the-meter to be able to participate in the FR market.

Finally, Ormat Technologies, through Viridity Energy has just completed the construction of two in-front-of-the-meter 20 MW/20 MWh Li-ion systems located in Plumsted Township and Alpha, New Jersey. The facilities are owned and operated by Viridity Energy to provide ancillary services to assist PJM Interconnection, in balancing the electric grid, and will also be available as a capacity asset. The projected average revenue for 2019 amounted to $7–8 million, mainly from ancillary services. The projects' revenues may vary from period to period as they are based on spot prices.[144] We are currently not aware of any incentive from the NJ BPU towards the construction of these two facilities, which could demonstrate that investors may be willing to start investing in ES in New Jersey.

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[141] PSE&G. 2018. "PSE&G Solar Storage Project in Service at Pennington DPW Building." (*PSE&G Newsroom.* May 17, 2018. https://nj.pseg.com/newsroom/newsrelease6).

[142] New Jersey Board of Public Utilities Clean Energy Program website. (Accessed May 5, 2019. http://www.njcleanenergy.com).

[143] Private communication with NJ BPU, April 3, 2019.

[144] Ormat Technologies. 2018. "Ormat's Viridity to Begin Construction of 40MWh Energy Storage Systems in New Jersey." *(Globe Newswire*. April 16, 2018. Accessed May 13, 2019. https://www.globenewswire.com/news-release/2018/04/16/1472396/0/en/Ormat-s-Viridity-to-Begin-Construction-of-40MWh-Energy-Storage-Systems-in-New-Jersey.html)

Lead-acid aqueous batteries

Lead-acid batteries were discovered 150 years ago (Figure 39**)** and are the oldest and most commercially mature rechargeable battery technology in the world. They are low energy density compared to competing battery technologies, including Li-ion. Despite this attribute, there have been significant advances leading to the development of various designs with different characteristics, cost, and performance serving a multitude of applications, both mobile and stationary. As such, lead-acid batteries hold the largest share of the broad rechargeable battery market.[145] With respect to utility applications, according to the 2018 NREL report, there exist 79 lead acid installations worldwide, totaling 194 MW in power and 216 MWh in capacity with an average duration of 1.1 hours.[146]

Technology:

The most common type of lead-acid battery consists of the low cost "Starting, Lighting, and Igniting (SLI)" design used to power engine starters in the automobile, naval, and aeronautical sectors. In addition, lead-acid batteries are utilized to provide uninterruptable power supply (UPS) to telecommunication towers, data networks, and anything that needs continuous power in case of power failure. Finally, lead-acid batteries have also been successfully adopted in small-scale domestic, commercial, and industrial energy storage applications, as well as utility-scale installations deployed as early as the late 1980s. Although Li-ion currently dominates the ES for grid applications, Figure 53 reveals that lead-acid technology was still deployed in the third quarter of 2018, although at a very small percentage. By 2018, the global installed capacities of lead-acid energy storage systems amounted to 194 MW and 217 MWh, with an average system rating of 2.5 MW in power, 2.7 MWh in energy, and 1.1 h-duration.[147]

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[145] Christophe Pillot. 2017. "The Rechargeable Battery Market and Main Trends 2016-2025." (Avicienne. PowerPoint presented at 33rd International Battery Seminar and Exhibit. Fort Lauderdale, FL. March 20, 2017. http://cii-resource.com/cet/FBC-TUT8/Presentations/Pillot_Christophe.pdf).

[146] Ran Fu, Timothy Remo, and Robert Margolis. 2018. *2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark*. (Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71714. https://www.nrel.gov/docs/fy19osti/71714.pdf.)

[147] Ran Fu, Timothy Remo, and Robert Margolis. 2018. *2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark*. (Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71714. https://www.nrel.gov/docs/fy19osti/71714.pdf.)

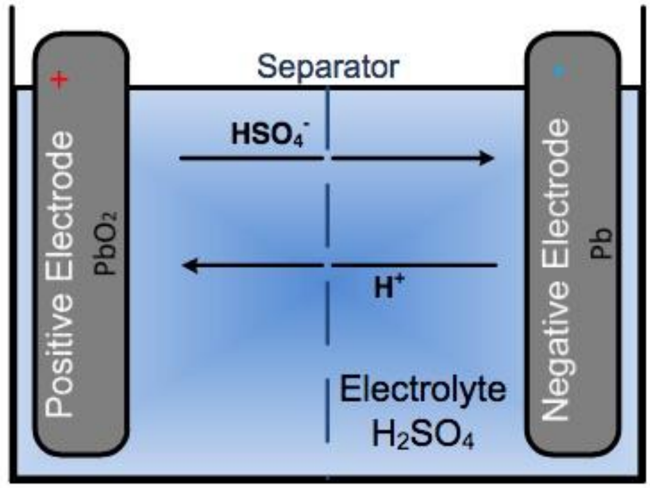

Figure 63: Working principles of a lead-acid battery.[148]

As illustrated in Figure 63, lead-acid batteries are composed of stacked cells of a metallic lead (Pb) negative electrode and a lead dioxide (PbO_2) positive electrode, separated by a highly porous separator immersed in aqueous sulfuric acid solution, typically 37% sulfuric acid by weight. Upon discharge, both electrodes generate lead sulphate ($PbSO_4$) concomitant to the dilution of the acid concentration of the electrolyte solution due to the formation of water and consumption of acid species. Upon charge, all reactions are reversible, including the release of the acid species and intake of water, enabling the electrolyte to regain its initial concentration.

Environmental Impact:

Lead acid batteries contain large quantities of toxic lead and corrosive sulfuric acid. However, lead acid batteries, inclusive of the electrodes, electrolytes, and even its polymer casing, are now almost 100% recyclable. The sulfuric acid is neutralized and the lead is recycled. 99% of the cells are collected and recycled in a closed loop system; standard regulations and processes are already in place since lead is the most efficiently recycled commodity metal in the European Union and in the United States.[149]

[148] Dirk and Fuchs Sauer, Georg and Lunz, Benedikt and Matthias Leuthold. 2012. *Technology Overview on Electricity Storage - Overview on the potential and on the deployment perspectives of electricity storage technologies.* On behalf of Smart Energy for Europe Platform GmbH (SEFEP), Institute for Power Electronics and Electrical Drives (ISEA), RWTH Aachen University Chair for Electrochemical Energy Storage Systems. DOI: 10.13140/RG.2.1.5191.5925).
[149] G. J. May, A. Davidson, and B. Monahov. 2018.“ Lead batteries for utility energy storage: A review.” (Journal of Energy Storage, vol. 15, p. 145-157, 2018).

*Table 17: List of selected lead-acid battery storage systems installed in the United States and in Japan showing reference number used for discussion, location, project name, (de)-commissioning year, power and capacity rating, duration time, siting, business model, total installation cost then per unit of power and energy, and the type of batteries that were used. Systems not highlighted are advanced VRLA batteries, highlighted in blue are based on flooded lead-acid batteries, highlighted in green are based on UltraBattery® hybrid batteries, and finally highlighted in red are advanced lead carbon hybrid supercapacitors. The capacity and duration noted with * were derived from reference [150] stating 3 MW of ancillary services could be provided for up to 22 minutes.[151]*

Ref.	Location	Project Name	Paired Grid Resource	Commiss.	Power	Capacity	Duration	Siting	Business Model	Capital Expenditure (CAPEX)	CAPEX /kW	CAPEX /kWh	Type of Lead-Acid Battery
#				Year	MW	MWh	h:mm		Owner	$	$/kW	$/kWh	
1	Puerto Rico, San Juan	Puerto Rico Electric Power Authority (PREPA) Battery System		1994 (decom. 1999)	20	14	0:42	Primary Distribution	Utility-Owned	$20,300,000	$1,015	$1,450	*Flooded Lead Acid* (flat plate), General Electric
2	Puerto Rico, San Juan	PREPA BESS 2		2004	20	14	0:40	Primary Distribution	Utility-Owned	$11,500,000	$575	$821	*Flooded Lead Acid* (tubular positive plate), General Electric
3	California, Chino	SCE Chino Battery Storage Project		1988 (decom. 1997)	10	40	4:00		Utility-Owned				*Flooded Lead Acid,* Exide Technologies
4	Japan, Shiura	Shiura Wind Farm Battery Storage Project	15.4 MW Wind	2009	4.5	10.5	2:20		Third-Party-Owned	-	-	-	*Advanced VRLA,* Hitachi
5	Japan, Yuza	Yuza Wind Farm Battery Storage Project	15.4 MW Wind	2010	4.5	10.5	2:20		Third-Party-Owned	-	-	-	*Advanced VRLA,* Hitachi
6	Pennsylvenia, Lyon Station	East Penn Manufacturing *Demonstration* Project for Ancillary Services	-	2012	3.6	0.75*	4:48*		Customer-Owned	-	-	-	*UltraBattery® Hybrid battery,* Ecoult/ East Penn Manufacturing
7	Alaska, Metlakatla	Metlakatla Battery Storage Project (Cell replacement in 2008)		1997	1	1.4	1:24	Primary Distribution	Utility-Owned	$2,319,978	$2,320	$1,657	*Advanced VRLA,* GNB Industrial Battery (now Exide Technologies)
8	New Mexico, Los Alamos	NEDO New Mexico Smart Grid *Demonstration* Project		2009	0.8	0.8	1:00		Third-Party-Owned				*Advanced VRLA,* Hitachi
9	North Carolina, Statesville	Crescent Electric Membership Cooperative BESS		1987 (decom. 2002)	0.5	0.5	1:00		Utility-Owned				*Flooded Lead Acid,* GNB Industrial Battery (now Exide Technologies)
10	New Jersey, Hillside	Hillside Energy Storage System (at undisclosed facility)	575 kw PV	2014	0.5	0.5	1:00		Customer-Owned	-	-	-	*Advanced Lead-Acid Carbon Hybrid Supercapacitor,* Axion Power International
11	New York, Brooklyn	Brooklyn	100 kW PV	2010	0.1	0.4	4:00		Customer-Owned	-	-	-	*Advanced VRLA,* Hitachi

Case Studies:

The first battery energy storage utilized for electric utility applications on the US Electric grid was the 500 kW/500 kWh Crescent Membership Cooperative lead-acid battery storage system commissioned in 1987 in Statesville (North Carolina) for peak shaving purposes. The system fabricated by GNB Industrial Battery (now Exide Technologies) was originally installed in 1983 at the Battery Energy Test Facility (BEST) at PSE&G in New Jersey as a joint venture of EPRI and the US DOE to establish a laboratory for testing large stationary batteries for electric utility applications. After testing over a few hundred cycles, it was purchased by the Electric Membership Cooperative (EMC) and moved to North Carolina ([9], Table 17).[152] The system comprised "flooded or vented (VLA)" type cells also fabricated by GNB Industrial Battery. These cells, which are vented and contain excess electrolyte, require periodic watering in order to prevent electrolyte depletion that would lead to battery failure. In addition, extend deep cycling should be avoided. The system operated from 1987 to 2002 and surpassed its 8-year

[150] U.S. Department of Energy. "East Penn Manufacturing Delivers New Battery Technology for Electrical Grid Support." Smart Grid Demonstration Program Fact Sheet. https://www.smartgrid.gov/files/East_Penn_Manufacturing-Delivers-New-Battery-Technology-Electrical-Grid-Support.pdf).

[151] U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).

[152] U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).

warranty and projected 2,000-cycle life. It was de-commissioned in May 2002 after a significant battery overcharge and therefore likely damage.[153] Its good performance was attributed to its robust construction, regular maintenance, and operation within its design characteristics (i.e., shallow cycling).[154]

Larger installations quickly followed, such as the South California Edison Battery Storage System deployed in Chino, California in 1988 and rated at 10 MW/40 MWh ([3], Table 17). At the time of its completion, the system was the largest utility battery energy storage in the world. The system contained GL-35 industrial flooded cells fabricated by Exide. Battery monitoring and management systems were included to optimize and prolong life. As such, temperature and acid level indicators were added, as well as automatic watering systems and air agitation to reduce electrolyte depletion and stratification, respectively.[155, 156] The system remained operational for nine years, slightly exceeding the eight-year warranty/projection. The system was a jointly sponsored project by the Electric Power Research Institute (EPRI), the Department of Energy, and the International Lead Zinc Research Organization (ILZRO), with Southern California Edison (SCE) as the host utility. The 4h-duration system served as an experimental facility to test and finally demonstrate the ability to perform wide range of grid applications including local area black start, peak shaving, load leveling, load following, T&D deferral, transmission line stability, VAR control and voltage support. The project successfully demonstrated lead-acid energy storage systems are capable of performing various services over an extended period of time. [157, 158]

The limits of the flooded batteries are well illustrated with the Puerto Rico Electric Power Authority (PREPA) battery system ([1], Table 17) installed in San Juan in 1994 for daily operation in a frequency control and spinning reserve mode. The battery system was chosen over combustion turbine-based generator for its faster response critical to prevent blackouts in an "island' system. The system was based on the 1987 German BEWAG system based on flooded cells with flat positive electrodes based on its good track record. However, the system was cycled more frequently than initially planned, leading to the premature aging of the batteries. This use mode resulted in the positive plate electrodes growth, which caused cell cracks, leaks, short circuits, and, ultimately, early battery failure. As a consequence the system was de-commissioned in 199l.[159, 160] The cells were replaced by flooded cells with tubular positive electrodes, and the system was re-commissioned in 2004 ([2], Table 17) to provide reserve capacity in response to a system disturbance and power factor correction when needed. However,

153 U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).
154 A. A. Akhil, G. Huff, A. B. Currier, B. C. Kaun, D. M. Rastler, S. Bingqing Chen, A. L. Cotter, D. T. Bradshaw, and W. D. Gauntlett. 2014. "DOE/EPRI Electricity storage handbook in collaboration with NRECA." (Sandia Report, SAND2015-1002, September 2014; https://prod-ng.sandia.gov/techlib-noauth/access-control.cgi/2015/151002.pdf)
155 Michael L. Jaeck. (ed.). 1989. *Primary and secondary lead processing.* (Proceedings of the International Symposium on Primary and Secondary Lead Processing. Permagon Press, 1989).
156 G. J. May, A. Davidson, and B. Monahov. 2018. " Lead batteries for utility energy storage: A review." (Journal of Energy Storage, vol. 15, p. 145-157, 2018).
157 U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).
158 D. H. Doughty, P. C. Butler, A. A. Akhil, N. H. Clark, and J. D. Boyes, 2010. "Batteries for large scale stationary electrical energy storage." (*The Electrochemical Society Interface*. Fall 2010 https://www.electrochem.org/dl/interface/fal/fal10/fal10_p049-053.pdf).
159 U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).
160 M. Farber de Anda, J. D. Boyes, and W. Torres. 1999. *Lessons learned from the Puerto Rico battery energy storage system*. (Sandia Report, SAND99-2232, September 1999, https://www.osti.gov/servlets/purl/12662).

a fire stopped operations within two years of commissioning. Ongoing litigation paralyzed the system, which continues to sit idle.[161]

Lead-acid batteries with fundamentally contrasting constructions have also been deployed to further improve large-scale ES system performance. The "Valve-Regulated Lead Acid (VRLA)" cells are sealed and comprise a minimal amount of electrolyte, either immobilized liquid trapped in a glass fiber mat (AGM) or gelled (GEL). As opposed to the flooded design, these cells are essentially maintenance-free. VRLA AGM ABSOLYTE IIP lead acid cells by GNB Industrial Battery (now Exide Technologies) were deployed in the 1.0 MW/1.4 MWh (90 min) Metlakatka battery system commissioned in 1997 in Alaska ([7], Table 17). The system was paired to a hydroelectric and diesel generator mainly for voltage regulation and displacement of diesel generation (DG). The system operated successfully within the prescribed limits of the cells for 12 years (1997–2008) with the original set of cells and continues to function after cell replacement. Exide Technology reported the cost benefit analysis (CBA) performed over the 1997–2008 period, resulting in cost savings of $6.6 millions.[162] In addition, Exide Technologies evaluated the cells retrieved from the Metlakatka battery system and stated that there was little evidence of degradation and, as such could project a 15-year lifetime in similar applications.[163]

Hitachi claimed 17-year life projections for its VRLA "LL1500-W" batteries for applications including output stabilization from smart grids, from wind and solar generation, or any other source of power generation. Its battery development approach focused on positive electrodes of enhanced durability derived from high-density active material and strongly corrosive resistant alloy plates, in addition to silica electrolyte additives that prevent sulfation. These cells were deployed in several installations in Japan such as two 4.5 MW/10.5 MWh systems to stabilize wind power generation, in Shiura deployed in 2009 ([4], Table 17) and in Yuaza installed in 2010 ([5], Table 17).[164] Smaller units have also been installed in the U.S., a 800kW/800kWh demonstration system in Los Alamos, New Mexico ([8], Table 17) partially funded by the department of the U. S. Department of Energy's Smart Grid Demonstration Program, and a 100 kW/400 kWh customer-owned system in Brooklyn, New York ([11], Table 17).

While carbon had previously been added as an additive to the electrodes, other approaches have integrated carbon in the negative electrode in significant amounts in order to further improve performance. Integration of carbon in the negative electrode enabled the VRLA cells to operate at partial depth of discharge for extended periods of time, with fewer refresh

[161] U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).
[162] Bharadwaj, S. 2012. "Clean energy storage for grid load leveling" The Metlakatla battery energy storage system twelve years of success." Exide Technologies. (PowerPoint presented at IRENA Conference, Port Vila, July 2012. https://www.irena.org//media/Files/IRENA/Agency/Articles/2012/Jul/7_Srinivas_Bharadwaj.pdf?la=en&hash=CFAA1E2C146BBA314516CA630C3E3D6F725552A4).
[163] A. A. Akhil, G. Huff, A. B. Currier, B. C. Kaun, D. M. Rastler, S. Bingqing Chen, A. L. Cotter, D. T. Bradshaw, and W. D. Gauntlett. 2014. "DOE/EPRI Electricity storage handbook in collaboration with NRECA." (Sandia Report, SAND2015-1002, September 2014; https://prod-ng.sandia.gov/techlib-noauth/access-control.cgi/2015/151002.pdf)
[164] M. Terada and H. Takabayashi. 2011. "Industrial storage device for low carbon society." (*Hitachi Review*. Vol. 60, No .1, p. 22-27, 2011).

cycles.[165] Such characteristic is essential for grid applications such as smoothing and frequency regulation. However, addition of large contents of carbon further lowers the devices energy densities, a big hurdle to these types of devices. Two different technologies went to market: 1) Axion Power International substituted the lead negative electrode entirely for carbon, leading to a hybrid asymmetric supercapacitor, as illustrated in Figure 64. In contrast, Ecoult (East Penn Manufacturing) substituted the lead negative electrode only partially with carbon, resulting in a hybrid system, as shown as the commercially traded UltraBattery® in Figure 64.

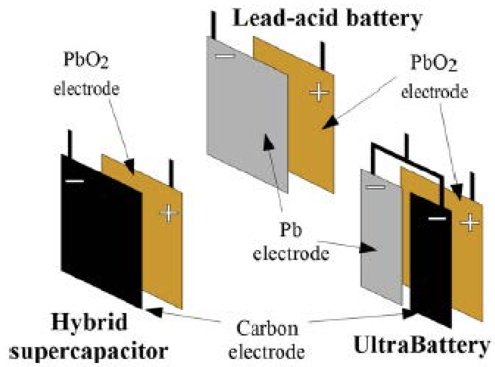

Figure 64: Types of lead-acid based technologies with carbon in the negative electrodes.[166]

Axion Power International claimed its hybrid asymmetric supercapacitor devices offered a high rate, a factor 4 increase in cycle life over conventional VRLA, and improved ability of cells to balance their performance within a string of cells. Unfortunately, the technology was plagued by two main drawbacks. The energy density was much lower than that obtained with the conventional lead acid technology and the voltage range was wider resulting in an increase in costs associated to the direct current/alternating current (dc/ac) conversion system. Although three systems were installed in the U.S., including one in New Jersey (based on the DOE database), Axion Power International filed for bankruptcy in 2018.[167] A 500 kW/500 kWh deployed in Hillside, New Jersey, is customer-owned and paired to a 575 kW PV system ([10], Table 17). Its main applications include black start, frequency regulation, solar generation shifting, and capacity firming.

The UltraBattery® by Ecoult (acquired by East Penn Manufacturing) has been reported to provide some advantages over conventional VRLA lead-acid batteries as it 1) prevents irreversible sulfation of the negative plate in partial state of charge cycling and eliminates the need for intermittent conditioning cycles, 2) has improved high-rate charge, 3) has better self-balancing of cells in series strings, and 4) has an energy density and voltage profile on discharge similar to that of a lead–acid battery. UltraBattery® hybrid devices have been deployed in several installations, including a 3.6 MW system commissioned in 2012 in Lyon Station,

[165] B.B. McKeon, J. Furukawa, and S. Fenstermacher. 2014. "Advanced lead-acid batteries and the development of grid-scale energy storage systems." (*Proceedings of the IEEE*. Vol. 102, No. 6, p. 951- 963, 2014.
[166] J. Lach, K. Wróbel, P. Podsadni, and A. Czerwiński. 2019. "Applications of carbon in lead-acid batteries: a review." (*Journal of Solid State Electrochemistry*. Vol. 23, p. 693-705, 2019).
[167] S. Federoff. 2018. "Axion Power files for chapter 7 bankruptcy." (*Pittsburg Business Times*. August 15, 2018. https://www.bizjournals.com/pittsburgh/news/2018/08/15/axion-power-files-for-chapter-7-bankruptcy.html).

Pennsylvania, to be used for frequency regulation ([6], Table 17). The system operates at 81% AC-based efficiency. The original cells are still performing well, and one string has been replaced with an optimized 2nd generation model of the UltraBattery® and redesigned rack. UltraBattery® hybrid devices deployed in several grid and renewable integration projects have demonstrated the ability to operate in reserve power mode, and they can switch from ancillary support to full islanded microgrid mode to provide power continuity in case of grid failure.[168, 169]

Xtreme Power founded in 2004, claimed that its cheap "super dry" PowerCell using a fiberglass technology, designed in the 1990s, would disrupt the ES industry.[170] Xtreme Power did not provide any detailed information on its PowerCell chemistry or its actual performance but claimed its key characteristics consisted of energy density like a Li-ion battery, power like a capacitor, low internal resistance and long cycle life over a broad range of state of charge, and improved safety compared to Li-ion.[171] By 2013, Xtreme Power had installed 77 MW of its PowerCells worldwide,[172] including the Notrees Battery Storage Project in Goldsmith, Texas, commissioned in 2013 ([14], Table 12). However, many of these installations consisted of pilot projects or were funded through third parties, such as the Department of Energy's smart grid stimulus program. Unfortunately, the 15 MW Xtreme Power battery system installed in Hawaii at Kahuku Wind Farm in March 2011 and supported by a U.S. DOE Office of Electricity loan guarantee was destroyed by fire on August 2012.[173] The combination of the shadow of the fire contradicting its safety robustness claim and the tight competition of the field led Xtreme Power to file for bankruptcy in 2014.[174] Its assets were sold to the German company Younicos. A few of the Xtreme Power systems have been decommissioned. In addition, PowerCell batteries have been replaced by Li-ion batteries in at least two systems in the U.S. within five years of installation. The Notrees system's PowerCell cells ([14], Table 12) have been replaced for Samsung cells within three years. The 3 MW/0.9 MWh Pillar Mountain system commissioned in 2012 in Kodiak Island, Alaska exchanged its batteries in 2017.

Summary:

In summary, lead-acid batteries have been demonstrated in many grid applications for short and long durations, over extended periods of time. There has been significant progress over the past decades to address power handling and longevity performance. Lead-acid batteries have achieved longer cycle life (250–2500) and longer lifetime (3–15 years) with low self-discharge (0.1 to 0.4% per day). Newer systems are also more efficient, in the 80% range (70–82%, AC-

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[168] G. J. May, A. Davidson, and B. Monahov. 2018. "Lead batteries for utility energy storage: A review." (*Journal of Energy Storage* vol. 15, p. 145-157, 2018).
[169] East Penn Manufacturing. 2015. "Grid-scale energy storage demonstration of ancillary services using the UltraBattery® technology." (*Smart Grid Program, Final Technical Report*. Award Number DE-OE0000302. https://www.smartgrid.gov/files/OE0000302_EastPenn_FinalRep.pdf).
[170] St. J. John. 2009. "Xtreme Power: Super Dry Battery." (*Greentech Media.* November 25, 2009 https://www.greentechmedia.com/articles/read/xtreme-power-super-dry-battery#gs.8r3woq).
[171] True Sustainable. "Xtreme Power batteries." (Accessed May 5, 2019. http://truesustainable.com/energy-storage/xtreme-power-batteries.html#.XMdX-aZ7nHc).
[172] St. J. John. 2013. "Xtreme Power to sell battery factory, focus on software." (*Greentech Media*. April 5, 2013. https://www.greentechmedia.com/articles/read/xtreme-power-to-sell- battery-factory-focus-on-software#gs.8r6yd8).
[173] U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).
[174] St. J. John. 2014. "Bankrupt grid battery alert: Xtreme Power bought by Germany's Younicos." (*Greentech Media.* April 14, 2014. https://www.greentechmedia.com/articles/read/bankrupt-grid-battery-alert-xtreme-power-bought-by-germanys-younicos#gs.8rbovj).

based). However, energy densities are low compared to competing battery energy storage (such as Li-ion, NaS, ZEBRA) with 30–50 Wh/kg in specific energy, 50–80 Wh/L in energy density, and 90–700 W/L in power density. Overall, lead-acid batteries' characteristics remain inferior to those of Li-ion batteries, and the use of hazardous lead may restrict the locations of the system.

Table 17 shows the PREPA battery system (42-minute duration) costs $1,450 per kWh, while the Metklaka system (1h 24min duration) was higher at $1,657, most likely due to the more remote location. The replacement of the PREPA batteries in 2004 amounted to $821 per kWh. The cost of the advanced sealed lead acid batteries required for the utility-scale systems serving several applications come at a premium with respect to the low cost SLI batteries, thereby significantly diminishing the economic benefit over Li-ion technology, whose costs have been rapidly decreasing. The lead-acid technology has been deployed only sporadically since 2013 (Figure 52). With the exception of the 4th quarter of 2013 when it was deployed at more than 10%, lead acid technology was deployed at a few percent of the global quarterly installed capacacity. In 2017**,** the lead-acid technology only constituted 3% of the electrochemical global capacity (Figure 52), much lower than the 59% of Li-ion technolology, which is still rapidly growing.

However, there is still some interest in the lead-acid technology as they are reliable (if operated within prescribed conditions), safer since they are based on an aqueous electrolyte and non-flammable active materials, and, finally, are currently almost 100% recyclable. A pre-competitive R&D agreement was signed in October 2018 by the Department of Energy's Argonne National Laboratory with the Advanced Lead Acid Battery Consortium, a team of 14 industrial members, to further improve lead-acid batteries performance.[175]

[175] S. Koppes. 2018. "Battery mainstay headed for high-tech makeover." (Argonne National Laboratory. Press Release October 16, 2018. https://www.anl.gov/article/battery-mainstay-headed-for-hightech-makeover).

Nickel-based aqueous batteries

By 2017, nickel-based aqueous batteries constituted 2% of the global rechargeable electrochemical energy storage total installed capacity (Figure 40**)** in contrast, Li-ion which captured the largest market share, represented 59%. With respect to utility installations, NREL reported a total of six projects amounting to 30.3 MW in power and 7.9 MWh.[176]

Nickel-cadmium (NiCd) batteries

Technology:

Nickel-cadmium batteries invented in 1899 are based on a nickel hydroxide (NiOOH) positive electrode and a cadmium (Cd) metal negative electrode immersed in a potassium hydroxide (KOH) electrolyte (Figure 65**)**. They have been developed in many form factors, including typical small size AA and 9V batteries but also larger size flooded and portable sealed designs. NiCd batteries served many different application markets, including consumer portable electronics, and medical, automobile, industrial, and aeronautic sectors.

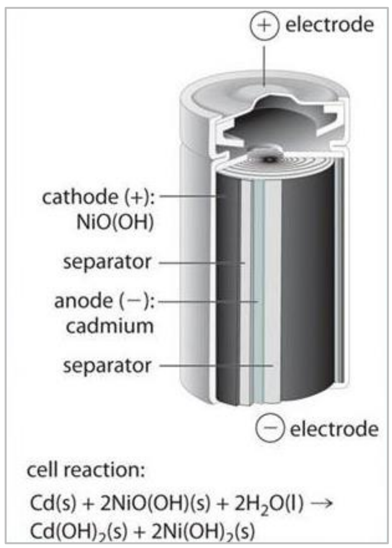

Figure 65: Spiral wound NiCd schematic and overall cell reaction.[177]

The oldest design consists of the flooded pocket-plate construction, which may exhibit positive attributes for utility applications. They provide a low maintenance system with demonstrated reliable operation over extended cycling (>2000) and periods of time (8–25 years depending on cycling conditions). They are very robust, as they withstand physical and electrical abuse, such as overcharging, reversal, and short-circuiting. They have small self-discharge (0.2–

[176] Ran Fu, Timothy Remo, and Robert Margolis. 2018. *2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark*. (Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71714. https://www.nrel.gov/docs/fy19osti/71714.pdf).
[177] ChemHub. "Electro-chemistry/ Secondary Cells / Nickel Cadmium battery/ Lead-acid storage battery." (YouTube Video. 4:02. Published March 22, 2017. https://www.youtube.com/watch?v=Q0VSVy-IIM).

0.6% per day),[178] which can be mitigated with the application of a float charge[179] and therefore exhibit excellent long-term storage. In addition, they exhibit a relatively high discharge rate (60% at 5C) and can operate over a wide temperature range (-50°C to 50°C). Regarding the memory effect induced by shallow discharging, a simple periodic electrical conditioning restores performance. However, it has low specific energy (20–56 Wh/kg) and energy density (40–110 Wh/kg).[180]

Environmental Impact:

Although most industrial NiCd batteries are currently recycled today, the extreme toxicity and thus environmental unfriendliness of cadmium remains a major concern.[181] As such, if NiCd batteries are not recycled, they must be disposed of as hazardous waste.

Case Studies:

The only utility-owned large-scale NiCd energy storage system currently in operation in the U.S. is located in Fairbanks, Alaska. The Golden Valley Electric Association (GVEA) commissioned the system to serve as voltage support, power system stabilizer, spinning reserve, and reserve power for Fairbanks in the event of an outage on the transmission line connecting Fairbanks to Anchorage. Performance at low temperature was critical in the decision process leading to the choice of the NiCd technology.

The 25 MW/6.25 MWh system which started operations in 2003 contains 13,760 Saft Nife® SBH 920 high-performance flooded pocket-plate cells with an expected lifetime of more than 20 years. The system delivers the rated power of 27 MW for 15 minutes which gives GVEA the time to start up local generation in time of emergency black outs. Efficiencies ranged between 72–78% over an operating temperature range of – 40 to 50°C. In the first two years, the system prevented 81 power outages, totaling an estimated 15 hours of outage time.[182] "In Alaska, where winter temperatures drop below -50 F, preventing such outages can be a matter of life and death," according to Tim DeVries, project manager for GVEA. In 2018, it responded to 59 events. The system has been operating reliably and efficiently since it came online 15 years ago. Good maintenance enabled by highly reliable and accurate battery monitoring has been essential to achieve such durability.[183] Total cost of the 15-minutes system (i.e., short duration) including installation and disposal of the batteries by Saft, amounted to $35 million,[184] equivalent to a $1,400 per kW and $ 5,600 per kWh. The remote location of the site certainly raises costs but

[178] X. Luo, J. Wang, M. Dooner, and D. Clarke. 2015. "Overview of current development in electrical energy storage technologies and the application potential in power system operation." (*Applied Energy.* vol.137, p.511-536, 2015).
[179] K. Bradbury. 2010. *Energy storage technology review.* (August 2010. https://www.kylebradbury.org/docs/papers/Energy-Storage-Technology-Review-Kyle-Bradbury-2010.pdf).
[180] David Linden and Thomas B. Reddy. 1995. *Handbook of Batteries*. Third Edition. (McGraw-Hill, 1995).
[181] K. Bradbury. 2010. *Energy storage technology review.* (August 2010. https://www.kylebradbury.org/docs/papers/Energy-Storage-Technology-Review-Kyle-Bradbury-2010.pdf).
[182] GVEA. "Battery Energy Storage System (BESS)" (Accessed May 5, 2019. http://www.gvea.com/energy/bess).
[183] S. Blankinship. 2006. "World's largest battery storage system marks second year of operation." (*Power Engineering*. January 01, 2006. https://www.power-eng.com/articles/print/volume-110/issue-1/dg-update/worldrsquos-largest-battery-storage-system-marks-second-year-of-operation.html).
[184] S. Blankinship. 2006. "World's largest battery storage system marks second year of operation." (*Power Engineering*. January 01, 2006. https://www.power-eng.com/articles/print/volume-110/issue-1/dg-update/worldrsquos-largest-battery-storage-system-marks-second-year-of-operation.html).

NiCd batteries are also more expensive than lead-acid batteries.

A smaller system rated at 3 MW/6 MWh was installed in Bonaire (Netherlands), a small island off Venezuela, in 2010. Paired to a 11 MW wind farm and 14 MW diesel generator, it also serves as electric supply reserve capacity and black start in case of emergency blackouts, time shift, and supply capacity.[185]

Although these systems are performing well and within expectations, low energy density, limited economic incentive, and the high toxicity of cadmium limit the use of the NiCd technology for future utility-scale applications.

Nickel-metal hydride (NiMH) batteries

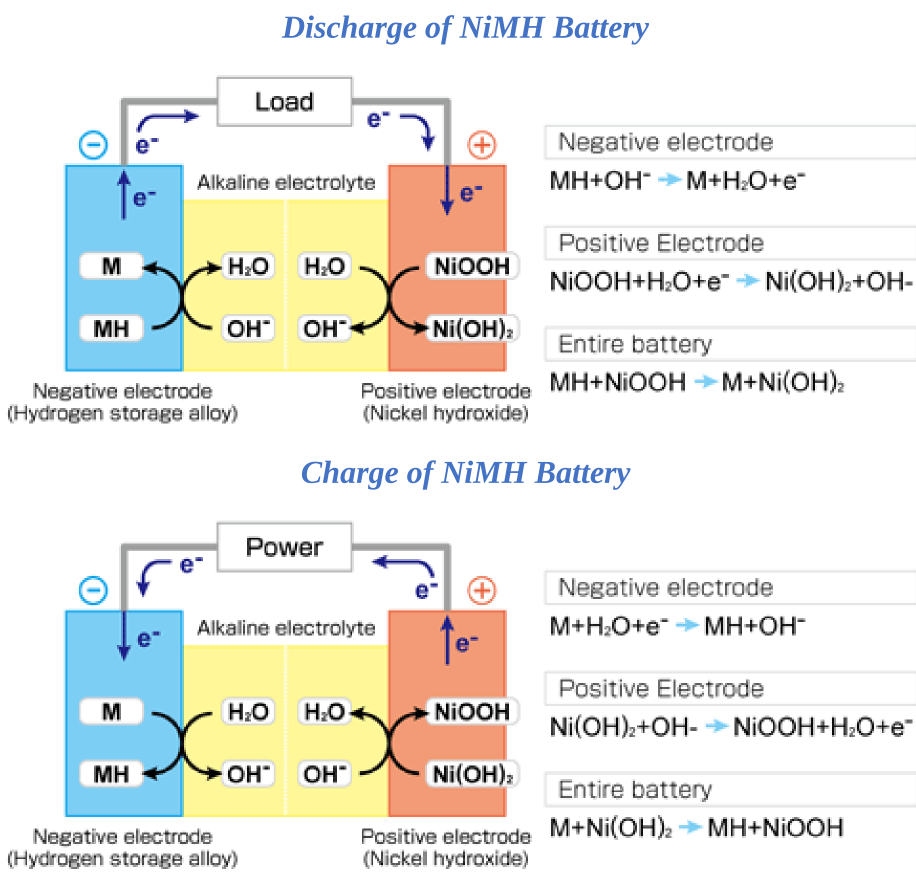

Figure 66: Working principles of a NiMH battery discharge (top) and charge (bottom).[186]

[185] U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).
[186] Kawasaki. "Battery Energy Storage System, Frequently Asked Questions" (Accessed April 28, 2019. http://global.kawasaki.com/en/energy/solutions/battery_energy/questions/index.html).

Technology:

The NiMH battery, a newer chemistry, is similar to the NiCd battery except that a hydrogen-absorbing metal alloy is used as the negative electrode instead of cadmium. The use of a hydrogen alloy as the negative electrode significantly increases the energy density and diminishes the memory effect relative to NiCd. Its working principle is illustrated in Figure 66. As such, NiMH batteries provide several benefits over the NiCd technology, such as higher specific energy (40–90 Wh/kg) and energy density (80–250 Wh/L),[187, 188] rapid recharge capability, and minimal environmental impact, as it is devoid of cadmium metal. Cycle life (at 80% depth of discharge) extended to 600–1200 cycles with ten years' lifetime. However, its high self-discharge rate of 5–20% per day and its sensitivity to deep cycling has been reported as the main cause that precludes its use in utility-scale applications.[189] While it has not been used for grid applications, it has extensively been utilized in a wide range of other applications in the commercial, industrial, automotive and aerospace sectors. Li-ion technology has, however, now captured a significant part of the NiMH share in these markets.

Environmental Impact:

The NiMH batteries using a hydrogen alloy instead of cadmium are more environmentally friendly than their NiCd counterparts.

[187] David Linden and Thomas B. Reddy. 1995. *Handbook of Batteries*. Third Edition. (McGraw-Hill, 1995).
[188] International Electrotechnical Commission (IEC). 2011."Electrical Energy Storage Whitepaper." (*IEC White Papers and Technology Reports*. https://www.iec.ch/whitepaper/energystorage/).
[189] Luo, X. , J. Wang, M. Dooner, and D. Clarke, 2015. "Overview of current development in electrical energy storage technologies and the application potential in power system operation." (*Applied Energy.* vol.137, p.511-536, 2015).

High temperature batteries

The rechargeable high temperature batteries discussed herein are based on sodium metal and offer attractive characteristics for large-scale energy storage applications. While many sodium-based batteries have been proposed over the years, two variants based on a beta-alumina solid-state electrolyte concept dominated the field. The sodium sulfur (NaS) and sodium nickel chloride (or ZEBRA) batteries, were developed further and brought to market. These batteries need to remain at high temperature (270 to 350°C) to operate. Indeed, above 270°C, all (for NaS) or portions (for ZEBRA) of the electrode materials exist in a molten state, which provide sufficient ionic conductivity to diffuse through the solid-state electrolyte. A core advantage of these cells, beyond the low-cost Na, is that the individual cell can be made to be very large capacity thanks to the high diffusion rates. This further reduces cost and complexity of manufacture relative to chemistries such as Li-ion.

Sodium Sulfur (NaS) Batteries

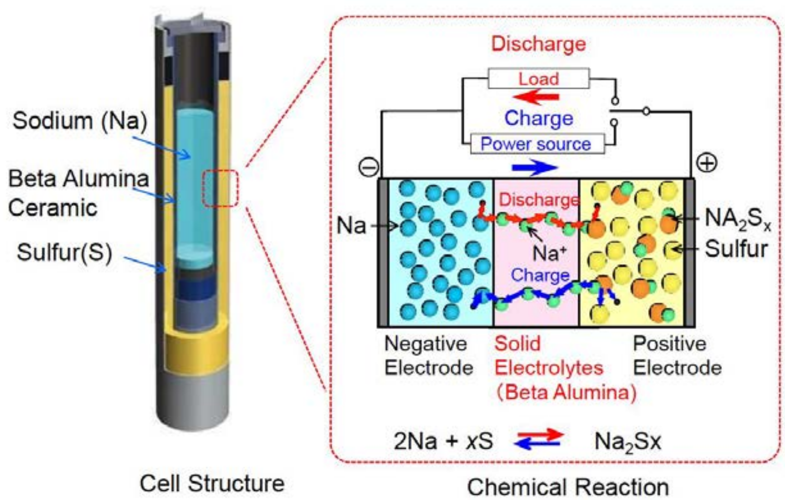

Figure 67: Schematics of a basic NaS cell structure and working principles of the NaS battery.[190]

Figure 67 shows a schematic of a basic NaS cylindrical cell with the sodium (Na) negative electrode at the core and the sulfur (S) positive electrode on the outside separated by the beta-alumina ceramic separator. During operation in the 270 to 350°C temperature range, both electrodes are in the molten state. Upon discharge, sodium and sulfur react to form immiscible polysulfides, which progressively convert into higher sulfide content components as free sulfur is consumed. Reactions are reversed upon charge.

[190] T. Hatta. 2018. "NAS Sodium Sulfur Battery Energy Storage, NGK Insulators." (PowerPoint presented at Asia Clean Forum, June 4-8, 2018. http://asiacleanenergyforum.pi.bypronto.com/2/wp-content/uploads/sites/2/2018/06/Tetsuya-Hatta-NAS-Battery.pdf).

Ford Motor Company pioneered the technology in the 1966 to power its early electric car models. There were several NaS battery developers for stationary applications that included Ford Aerospace, NGK Insulators Ltd (NGK in collaboration with Tokyo Electric Power Co. (TEPCO)), Yuasa Corp., Hitachi Ltd, Highes, and Silent Power Ldt.[191] Most of these entities terminated their effort, and NGK is currently the dominant player in the NaS battery market and provided the NaS batteries for most of the energy storage systems listed in Table 18 installed worldwide between 2004 and 2019. TEPCO's and NGK declared their interest in 1983 (Figure 39) and started a collaboration in 1984 in search of cells capable of generating enough capacity for use in load leveling and peak shaving applications for up to 8h durations. NGK's NaS cells went to market in 2002.[192]

Technology:

NaS batteries exhibit very desirable attributes, including good energy density (150–370Wh/L), long cycle life (4500–5000 cycles at 90% depth of discharge), long life time (15 years), long discharge time (typically > 6 hours), small electrochemical self-discharge (0.05–1% per day), relatively high energy efficiency (75% AC-based), have fast response (milliseconds), insensitivity to ambient conditions (sealed heat-temperature system), high capacity per cell, and flexible operation, as cells are functional over a wide range of conditions (rate and depth of discharge). In addition, NaS batteries use cheap raw materials so there is a potential for low cost. In terms of the NaS technology limitations, freeze-thaw durability, associated to the use of a ceramic electrolyte with limited fracture toughness that can be subjected to high levels of thermally driven mechanical stress, can be a concern. As such, NaS cells are ideal for utility applications in continuous use as the cells will not have to go through the deleterious thermal excursions. These batteries should be designed with safety considerations related to the presence of corrosive molten salts and operations at high temperatures. A thermal management system (TMS) is added in NGK/to maintain and control the temperature of the cells within the battery in order to continue operations and prevent system failure. There are two distinct modes: during normal operation and idle periods it minimizes heat loss, while during high-power discharges it dissipates the exothermic reaction heat to prevent the temperature from reaching too high levels or from creating undesirable temperature differentials within the battery.[193] However, if the system is used daily, the batteries' heat maintain the systems temperature as long as the system is properly insulated. Finally, cells are hermetically sealed with durable seals for safety and packaged into modules of 50 kWh surrounded with sand for added thermal capacitance, packing stability, and to limit oxidation in case of cell failure (Figure 68).[194] In 2011, the NGK system installed at the Tsukuba Plant (Tokyo, Japan) of Mitsubishi Materials Corporation caught fire,[195] resulting in a temporary halt of the manufacture of the NGK NaS batteries while the incident was under investigation. Based on the results of this investigation, NGK claimed to have voluntarily

[191] David Linden and Thomas B. Reddy. 1995. *Handbook of Batteries*. Third Edition. (McGraw-Hill, 1995).
[192] NGK Insulators Ldt. 2007. "Sodium-sulfur batteries for energy storage – Load leveling & renewable energy." (PowerPoint Presentation. June 2007. http://promexico.me/Rubenius/NGK%20NAS%20Batteries.pdf).
[193] David Linden and Thomas B. Reddy. 1995. *Handbook of Batteries*. Third Edition. (McGraw-Hill, 1995).
[194] A. A. Akhil, G. Huff, A. B. Currier, B. C. Kaun, D. M. Rastler, S. Bingqing Chen, A. L. Cotter, D. T. Bradshaw, and W. D. Gauntlett. 2014. "DOE/EPRI Electricity storage handbook in collaboration with NRECA." (Sandia Report, SAND2015-1002, September 2014; https://prod-ng.sandia.gov/techlib-noauth/access-control.cgi/2015/151002.pdf).
[195] E. Wesoff. 2011. "Exploding sodium sulfur batteries from NGK energy storage. Exploding – and not in a good way. An emerging market faces growing pains as renewables address the globe's largest challenge." (*Greentech Media*. November 01, 2011. https://www.greentechmedia.com/articles/read/exploding-sodium-sulfur-batteries-from-ngk-energy-storage#gs.8k04z6)

implemented safety enhancement measures, including an improved monitoring system, under the guidance of the Fire and Disaster Management Agency.[196]

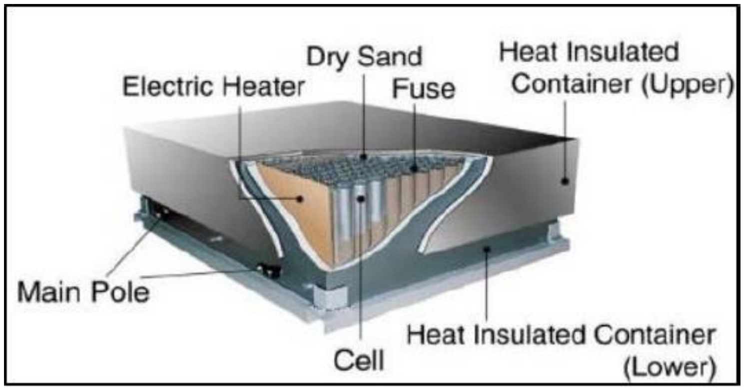

Figure 68: NaS battery module components.[197]

Environmental Impact:

Over 98% of the NaS materials can be recycled, and only sodium requires recycling as a hazardous material because of its flammability in contact with air.[198] As such, the environmental impact is minimal.

Case Studies:

NGK has reported a total global installation of 530 MW in power (360 MW being domestic) and 3,700 MWh in capacity over more than 200 sites.[199] Selected ES systems deployed over the 2004–2019 period listed in Table 18 show systems of various sizes including renewable generation sites, transmission lines, substations and behind-the-meter as indicated by the siting in transmission but also in primary and secondary distribution, by the utility-, third party-, or customer-ownership, and the pairing with renewable energy sources and thermal plants. The systems range from 1 MW/6 MWh pilot projects in Berlin, Germany, and in Los Alamos, New Mexico, installed in 2012 ([25] & [26], Table 18) to the largest electrochemical energy storage system in the world inaugurated in January 2019 in Abu Dhabi, United Arab Emirates and rated at 108 MW/648 MWh ([1], Table 18).

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196 U.S. DOE Global Energy Storage Database. (Accessed May 5, 2019. https://www.energystorageexchange.org/).

197 Electrical Power Research Institute (EPRI). 2009. *1 MW / 7.2 MWh NaS Battery Demonstration and Case Study Update*. (EPRI ID: 1017814. EPRI. Palo Alto, CA. December 2009).

198 C.H. Dustmann, Bito A. Safety, J. Garche, C. Dyer, P. Moseley, Z. Ogumi, D. Rand and B. Scrosati, Editors. 2009. (*Encyclopedia of Electrochemical Power Sources*. Vol 4. Amsterdam: Elsevier, p. 324–333, 2009).

199 T. Hatta. 2018. "NAS Sodium Sulfur Battery Energy Storage, NGK Insulators." (PowerPoint presented at Asia Clean Forum, June 4-8, 2018. http://asiacleanenergyforum.pi.bypronto.com/2/wp-content/uploads/sites/2/2018/06/Tetsuya-Hatta-NAS-Battery.pdf).

Table 18: Selected NaS energy storage systems already installed, worldwide. [200]
*List shows reference number used for discussion, location, project name, commissioning year, power and capacity rating, duration time, siting, business model, CAPEX cost, CAPEX per unit of power and energy, and battery vendor as well vendor for system integration. * The cost of 100 million Euros cost for the Terna systems was converted to USD using the average yearly rate from the IRS for 2013.*

Ref.	Location	Project Name	Paired Grid Resource	Commiss.	Siting	Business Model	Power	Capacity	Duration	CAPEX	CAPEX /kW	CAPEX /kWh	Energy Storage Tech.
#				Year		Owner	MW	MWh	h:mm	$	$/kW	$/kWh	System / Battery
1	United Arab Emirates, Abu Dhabi	ADWEA Abu Dhabi		2019		Utility	108	648	6:00				NGK Insulators
2	Japan, Kyusyu, Fukuoka	Buzen Substation	PV	2016		Utility	50	300	6:00				Mitsubishi Electric Corp. / NGK Insulators
3	Japan, Aomori, Rokkasho	Rokkasho Village	51 MW Wind	2008	Transmission	Third-Party	34	245	7:00				NGK Insulators
4	Italy, Campania, Flumeri	Terna SANC Flumeri		2015	Transmission	Utility	12	80	6:40				NGK Insulators
5	Italy, Campania, Miscano	Terna SANC Ginestra		2015	Transmission	Utility	12	80	6:40	127,713,921*	3,649	550	NGK Insulators
6	Italy, Campania, Scampitella	Terna SANC Scampitella		2015	Transmission	Utility	10.8	72	6:40				NGK Insulators
7	Japan, Ibaraki, Hitachinaka	Hitachi Automotive Plant System		2004		Customer	9.6	58	6:00				NGK Insulators
8	Japan, Tokyo, Ota-ku	Morigasaki Water Treatement Plant Energey Facility		2004		Customer	8	58.4	7:18				
9	Japan, Shimane, Nishinoshima	Chugoku Electric Power hybrid BESS Oki Islands *Demonstration Project*	2MW / 700 kWh Li-ion	2015		Utility	4.2	25.2	6:00				NGK Insulators
10	United States, TX, Presidio	Presidio Energy Storage System - American Electric Power		2010	Transmission	Utility	4	32	8:00	15,000,000	3,750	469	NGK-Locke, Inc. (JP)
11	Japan,Okinawa Miyakojima	Miyako Island Mega-Solar *Demonstration Project*	4 MW PV, Wind, Thermal Plant	2010	Transmission	Utility	4	28.8	7:12				
12	United States, CA, San Jose	Yerba Buena Battery Energy Storage *Pilot Project*		2014	Primary Distribution	Utility	4	28	7:00	18,000,000	4,500	643	NGK Insulators
13	Germany, Lower Saxony, Niedersachsen	Niedersachsen Hybrid Energy Storage *3 Year Demonstration Project*	7.5 MW / 2.5 MWh Hitachi Li-ion	2018		Utility	4	20	5:00				NGK Insulators
14	United States, CA, Vacaville	Vaca/Dixon Battery Energy Storage *Pilot Project*		2012	Primary Distribution	Utility	2	14	7:00	11,000,000	5,500	786	NGK Insulators
15	United States, W. VA, Milton	Milton Battery Energy Storage System		2008	Primary Distribution	Utility	2	12	6:00				American Electric Power /NGK Insulators
16	United States, IN, Churubusco	Churubusco Battery Energy Storage System		2008	Primary Distribution	Utility	2	12	6:00				American Electric Power /NGK Insulators
17	United States, OH, Bluffon	Bluffon Battery Energy Storage System		2008	Primary Distribution	Utility	2	12	6:00				American Electric Power /NGK Insulators
18	United States, W. VA, Charelston	Charleston Battery Energy Storage System		2006	Primary Distribution	Third-Party	1.2	7.2	6:00				American Electric Power /NGK Insulators
19	United Arab Emirates, Dubai	Mohammed bin Rashid Al Maktoum Solar Park	PV Park	2018		Customer	1.2	7.2	6:00				NGK Insulators
20	United States, MI, Luvernes	XCEL NGK MinnWind Wind-to-Battery Project	11 MW Wind	2008	Transmission	Utility	1	7.2	7:12	4,600,000	4,600	639	S&C Electric Company / NGK Insulators
21	United States, CA, Avalon	SCE Catalina Island Energy Storage		2012	Primary Distribution	Utility	1	7.2	7:12	6,108,000	6,108	848	NGK Insulators
22	France, Reunion, St. Andre	Reunion Island Pegase Project	10 MW PV, 2 MW PV, 11 MW Wind	2009		Utility	1	7.2	7:12				Bourbon Lumiere / NGK Insulators
23	Canada, BC, Field	BC Hydro Field Battery Energy Storage		2013	Transmission	Utility	1	6.5	6:30				S&C Electric Company / NGK Insulators
24	United States, NY, Garden City	Long Island Bus BESS - New York Power Authority		2009	Secondary Distribution	Customer	1	6.5	6:30	4,300,000	4,300	662	NGK Insulators
25	United States, NM, Los Alamos	Los Alamos - Collaborative Smart Grid Project *Demonstration Project*	PV, Smart Grid, Lead Acid Batteries	2012	Primary Distribution	Third-Party	1	6	6:00				NGK Insulators
26	Germany, Berlin	Berlin-Adlershof Project *Pilot Project*	200 kW/200 kWh lithium-ion	2012	Secondary Distribution	Customer	1	6	6:00				Younicos & Vattenfall / NGK Insulators

[200] U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).

The ADWEA Abu Dhabi system is also the "world's largest Virtual Battery Plant." The 6h-duration system consists of 15 smaller 6 h-duration systems that have been deployed across 10 locations, which either can be controlled as a single plant or individually. The rationale behind the selection of the NaS battery technology for the Abu Dhabi site, was: 1) NaS batteries are lower cost than Li-ion batteries for 6h discharge times, 2) NaS batteries are less sensitive to external temperature than Li-ion batteries since they are insulated to operate at high temperatures and should result in more robust cycling in sites located in hot climates, such as Abu Dhabi, 3) NaS batteries are robust and therefore appropriate for daily use at full depth of discharge, which make generation investment deferral possible, and 4) NaS batteries are lower cost compared to thermal generation plants.[201]

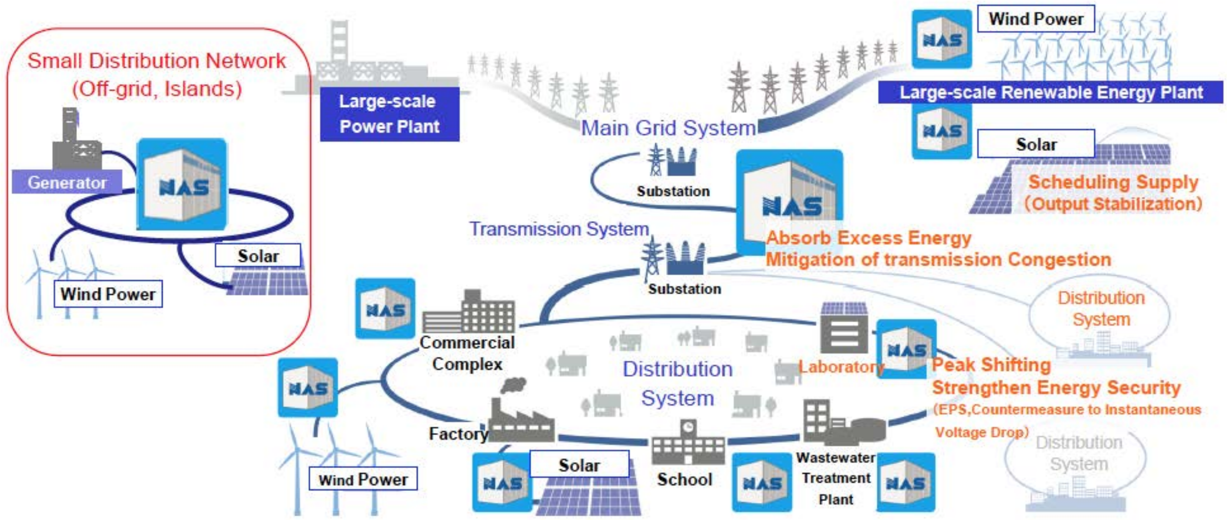

Figure 69: Selected applications for NaS battery systems as reported by NGK Insulators Ldt.[202]

NaS battery systems have been used for a wide range of grid applications, as illustrated by Table 19 and Figure 69. Since the NaS is a long duration technology, systems can be used to stack services, as shown in Table 19. Within transmission/distributions service applications, they have been used to absorb excess energy for mitigation of transmission congestion and for T/D upgrade deferral. They have also been deployed to perform all ancillary services, including frequency regulation, voltage support, load following, black start but also electric supply reserve capacity. They have also been utilized to integrate, stabilize, and time shift solar and wind. NaS have also been demonstrated to improve the efficiency of diesel generators and reduce air pollutants and greenhouse gases. Finally, they operate as back-up power supply as small distribution off-grid networks. Behind-the-meter, they can also provide some cost savings through bill management services ([7] & [8], Table 19).

[201] Colthorpe, A. "UAE integrates 648 MWh of sodium sulfur batteries in one swoop." (*Energy Storage News*. January 28, 2019. https://www.energy-storage.news/news/uae-integrates-648mwh-of-sodium-sulfur-batteries-in-one-swoop).
[202] T. Hatta. 2018. "NAS Sodium Sulfur Battery Energy Storage, NGK Insulators." (PowerPoint presented at Asia Clean Forum, June 4-8, 2018. http://asiacleanenergyforum.pi.bypronto.com/2/wp-content/uploads/sites/2/2018/06/Tetsuya-Hatta-NAS-Battery.pdf).

New "hybrid" systems combining both NaS and Li-ion technologies are currently being evaluated in demonstration projections of various sizes. The underlying concept is to use the long duration NaS battery to stabilize large, slow fluctuations, while the short-duration li-ion battery would absorb rapid, small fluctuations. In addition, NaS provide robustness and durability that Li-ion may lack. A few systems are already in operation, in a joint pilot project. Younicos and Vattenfall have installed a 1 MW/6 MWh NaS battery system and a smaller 200kW/200kWh Li-ion battery system at Younicos headquarters in Berlin in 2012 ([26], Table 19). In 2015, Chugoku Electric Power initiated its demonstration project at the Oki Islands, Japan, of a 4.2 MW/25.2 MWh NaS system combined to a 2 MW/700 kWh Li-ion system ([9], Table 19). Finally, the Niedersachsen hybrid energy storage three-year demonstration project with a 4 MW/20 MWh NaS battery and a 7.5 MW/2.5 MWh Li-ion battery started its operation in Germany in 2018 ([13], Table 19).

The costs of seven systems installed between 2009 and 2015 vary between $469 and $848 per kWh with an average of $657 per kWh (Table 18). The NaS technology has the potential to be on par or cheaper than Li-ion and possess desirable attributes for the grid market. The NaS technology constitutes a robust alternative or complementary technology to Li-ion for grid applications.

Table 19: Selected NaS energy storage systems and applications.
Table also shows reference number used for discussion, location, project name, commissioning year, power and capacity rating, duration time, siting, and business model.[203]

Ref.	Location	Project Name	Paired Grid Resource	Commiss.	Siting	Business Model	Power	Capacity	Duration	Ancillary Services					T&D Services		Bulk Energy Services		Renewable Integration Services			Customer Services
#				Year		Owner	MW	MWh	h:mm	Freq. Regulation	Electric Supply Reserve Cap.	Voltage Support	Black Start	Load Following	T. Congestion Relief	T/D Upgrade Deferral	Electric Energy Time Shift	Electric Supply Capacity	Ramping	Ren. Energy Time Shift	Ren. Capacity Firming	Electric Bill Mngt
1	United Arab Emirates, Abu Dhabi	ADWEA Abu Dhabi		2019		Utility	108	648	6:00								✓					
2	Japan, Kyusyu, Fukuoka	Buzen Substation	PV	2016		Utility	50	300	6:00	✓											✓	
3	Japan, Aomori, Rokkasho	Rokkasho Village	51 MW Wind	2008	Transmission	Third-Party	34	245	7:00		✓									✓	✓	
4	Italy, Campania, Flumeri	Terna SANC Flumeri		2015	Transmission	Utility	12	80	6:40	✓		✓			✓							
5	Italy, Campania, Miscano	Terna SANC Ginestra		2015	Transmission	Utility	12	80	6:40	✓		✓			✓							
6	Italy, Campania, Scampitella	Terna SANC Scampitella		2015	Transmission	Utility	10.8	72	6:40	✓		✓			✓							
7	Japan, Ibaraki, Hitachinaka	Hitachi Automotive Plant System		2004		Customer	9.6	58	6:00								✓					✓
8	Japan, Tokyo, Ota-ku	Morigasaki Water Treatement Plant Energey Facility		2004		Customer	8	58.4	7:18								✓					✓
9	Japan, Shimane, Nishinoshima	Chugoku Electric Power hybrid BESS - Oki Islands *Demonstration Project*	2MW / 700 kWh Li-ion	2015		Utility	4.2	25.2	6:00			✓									✓	
10	United States, TX, Presidio	Presidio Energy Storage System - American Electric Power		2010	Transmission	Utility	4	32	8:00		✓					✓		✓				
11	Japan,Okinawa Miyakojima	Miyako Island Mega-Solar *Demonstration Project*	4 MW PV, Wind, Thermal Plant	2010	Transmission	Utility	4	28.8	7:12	✓											✓	
12	United States, CA, San Jose	Yerba Buena Battery Energy Storage *Pilot Project*		2014	Primary Distribution	Utility	4	28	7:00	✓							✓				✓	
13	Germany, Lower Saxony, Niedersachsen	Niedersachsen Hybrid Energy Storage *3 Year Demonstration Project*	7.5 MW/ 2.5 MWh Hitachi Li-ion	2018		Utility	4	20	5:00								✓			✓		
14	United States, CA, Vacaville	Vaca/Dixon Battery Energy Storage *Pilot Project*		2012	Primary Distribution	Utility	2	14	7:00	✓				✓			✓				✓	
15	United States, W. VA, Milton	Milton Battery Energy Storage System		2008	Primary Distribution	Utility	2	12	6:00		✓					✓	✓					
16	United States, IN, Churubusco	Churubusco Battery Energy Storage System		2008	Primary Distribution	Utility	2	12	6:00		✓					✓	✓					
17	United States, OH, Bluffon	Bluffon Battery Energy Storage System		2008	Primary Distribution	Utility	2	12	6:00		✓					✓	✓					
18	United States, W. VA, Charelston	Charleston Battery Energy Storage System		2006	Primary Distribution	Third-Party	1.2	7.2	6:00							✓	✓					
19	United Arab Emirates, Dubai	Mohammed bin Rashid Al Maktoum Solar Park	PV Park	2018		Customer	1.2	7.2	6:00	✓							✓			✓	✓	
20	United States, MI, Luvernes	XCEL NGK MinnWind Wind-to-Battery Project	11 MW Wind	2008	Transmission	Utility	1	7.2	7:12	✓		✓					✓		✓			
21	United States, CA, Avalon	SCE Catalina Island Energy Storage		2012	Primary Distribution	Utility	1	7.2	7:12		✓			✓		✓						✓
22	France, Reunion, St. Andre	Reunion Island Pegase Project	10 MW PV, 2 MW PV, 11 MW Wind	2009		Utility	1	7.2	7:12								✓	✓				
23	Canada, BC, Field	BC Hydro Field Battery Energy Storage		2013	Transmission	Utility	1	6.5	6:30								✓	✓				
24	United States, NY, Garden City	Long Island Bus BESS - New York Power Authority		2009	Secondary Distribution	Customer	1	6.5	6:30		✓		✓			✓	✓					✓
25	United States, NM, Los Alamos	Los Alamos - Collaborative Smart Grid Project *Demonstration Project*	PV, Smart Grid, Lead Acid Batteries	2012	Primary Distribution	Third-Party	1	6	6:00					✓				✓	✓			
26	Germany, Berlin	Berlin-Adlershof Project *Pilot Project*	200 kW/200 kWh lithium-ion	2012	Secondary Distribution	Customer	1	6	6:00	✓												

[203] U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).

Sodium Nickel Chloride (ZEBRA) batteries

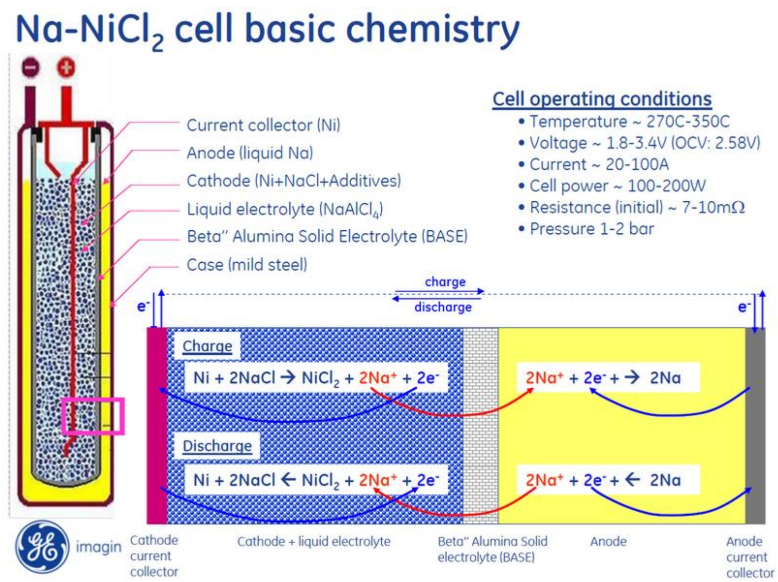

Figure 70: Schematics of a Sodium Nickel Chloride basic cell and its working principles.[204]

Developed in the 1980's, the sodium nickel chloride or ZEBRA battery (Figure 70) is based on a sodium negative electrode and a beta-alumina solid electrolyte, similar to that of the NaS technology. An important difference relative to NaS is that ZEBRA uses a porous solid positive electrode consisting of a mixture of nickel and active nickel chloride impregnated with a molten secondary electrolyte ($NaAlCl_4$) that facilitates transport of sodium ions to/from the beta-alumina electrolyte to/from the reaction site within the electrode. Cells are manufactured in the discharged stated from a mixture of sodium chloride and nickel, which transforms into nickel chloride and sodium upon charge. This improves safety considerations. Reactions are reversed upon discharge. Operating temperatures range over 270–350°C.

Technology:

The ZEBRA battery technology has many benefits. It is based on relatively low cost and abundant materials. The cells, fabricated in the discharged state, are sodium-free and are therefore intrinsically non-toxic, non-explosive and non-flammable, and are safe to handle and ship. Like the NaS technology, the sodium nickel chloride batteries, which are thermally insulated, are independent from ambient conditions.

The ZEBRA battery technology has slightly lower specific energy (100–200 Wh/kg), energy density (150–280 Wh/L), and power density (250–270 W/L) compared to the NaS technology. Due to the ceramic electrolyte, the battery has very little electrochemical self-discharge, however, the elevated operating temperature causes thermal self-discharge; if it is not cycling. Depending on the operation conditions, the thermal loss is compensated by the internal

[204] Green Car Congress (blog). "GE launches Durathon sodium-metal halide battery." (*Green Car Congress*. May 18, 2010. https://www.greencarcongress.com/2010/05/durathon-20100518.html).

electrical loss that is converted to heat so that the overall cell efficiency is 80–95%.[205] AC-based efficiencies can drop below 80%.[206]

The system is very robust, failure tolerant, and thereby maintenance-free. The exothermic heats of reactions are lower than for the NaS technology, and, as such, the temperature of the system is easier to maintain. All materials in the cells have a vapor pressure below 1 bar at its maximum temperature so that no gas should be released. The system also contains lower amounts of corrosive components, making the system safer. Safety is further enhanced by the double-walled and evacuated stainless steel thermal insulation box in which the cells are packaged into approximately 20 kW modules. Finally, there is no freeze / thaw limitation since the thermally induced mechanical stress on the solid-state electrolyte is low, thanks to the cell structure with the positive electrode located at the core (Figure 70), the smaller difference between the ambient temperature and the positive electrode solidification temperature, and lower mismatch in thermal expansion between the secondary and primary electrolyte.

Moreover, if the solid-state separator cracks, then the secondary electrolyte would react with sodium to form sodium chloride salt and aluminum, a safer failure mode than that which occurs in NaS. The cell can also withstand limited overcharge since the secondary electrolyte would react with nickel and provide additional sodium. This additional sodium would enable current to flow even at the end of charge, thereby preventing the voltage to rise further and protecting the solid-state electrolyte from potential failure. [207] When the cells fail they tend to develop low resistance resulting in voltage loss from one cell in the serial connection within the module rather than failure of the complete system.[208] No inter-cell connection or voltage taps is required, and systems can contain long series of batteries.[209] As such, the ZEBRA technology has relatively high cycle life (3000 cycles) and long lifetime (15 years).

<u>Environmental Impact:</u>

ZEBRA batteries are recycled through inexpensive processes. The first step consists of discharging the batteries in order to minimize the sodium content. In the second step, the nickel (II) chloride is reduced to nickel and shredded in equipment similar to that existing in the steel industry. The residual sodium does not cause any problem. In the third step, together with other scrap metals as the main feed, this shredder is fed into an electric arc melting furnace. Finally, the salt, the aluminum chloride, and, the ceramic partition go into the slag. The outgoing products consist of pig iron and slag, which are sold to the market. [210]

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[205] C.H. Dustmann, Bito A. Safety, J. Garche, C. Dyer, P. Moseley, Z. Ogumi, D. Rand and B. Scrosati, Editors. 2009. (*Encyclopedia of Electrochemical Power Sources*. Vol 4. Amsterdam: Elsevier, p. 324–333, 2009).
[206] M. Musio. 2017. "Terna's grid-scale battery storage projects. Results from experimentation." (Terna Group. PowerPoint presented at Nicosia, November 24, 2017. https://www.wesrch.com/energy/paper-details/pdf-TR1YL6000YPOS-terna-s-grid-scalre-battery-storage-projects#page1).
[207] C.H. Dustmann, Bito A. Safety, J. Garche, C. Dyer, P. Moseley, Z. Ogumi, D. Rand and B. Scrosati, Editors. 2009. (Encyclopedia of Electrochemical Power Sources. Vol 4. Amsterdam: Elsevier, p. 324–333, 2009).
[208] International Electrotechnical Commission (IEC). 2011."Electrical Energy Storage Whitepaper." (*IEC White Papers and Technology Reports*. https://www.iec.ch/whitepaper/energystorage/).
[209] David Linden and Thomas B. Reddy. 1995. *Handbook of Batteries*. Third Edition. (McGraw-Hill, 1995).
[210] C.H. Dustmann, Bito A. Safety, J. Garche, C. Dyer, P. Moseley, Z. Ogumi, D. Rand and B. Scrosati, Editors. 2009. (*Encyclopedia of Electrochemical Power Sources*. Vol 4. Amsterdam: Elsevier, p. 324–333, 2009).

It has also more recently been demonstrated that all of the resulting components of the recycling process, which includes nickel, salt, and boehmite, could be recycled. The nickel was reutilized in the stainless-steel industry, while the salt and ceramic was sold as a replacement for limestone used in road construction.

Case Studies:

The initial development of ZEBRA technology almost exclusively targeted the electric vehicle market and was the result of the effort of several integrated entities. In 1998, AEG Anglo Battery Holdings, which consisted of cooperation between the German entity AEG and the South-African Zebra Power Systems (ZPS) company, had advanced the technology to the production-ready level. In 1999, the Swiss company MES-DEA SA acquired the Zebra technology, including the production and development equipment and Beta Research & Development Ltd. In 2010, after successfully developing numerous ZEBRA cell prototypes in its laboratories, FIAMM Energy Technology S. p. A. (initially FIAMM Energy Storage Solutions) acquired MES-DEA SA, the only manufacturing company of sodium nickel chloride batteries in Europe, and founded the FZSONICK SA to produce cells and modules, to market its ZEBRA technology for stationary and grid applications. In 2017, Hitachi Chemical acquired 51% of its shares.[211] In addition, GE had also launched its Durathon sodium metal-halide battery for the UPS and utility markets and had officially inaugurated its new battery plant in New York in 2012.

By 2013, a few utility-scale projects were announced. By the end of 2015, a few systems in the 1 to 5 MW range built and started operations (Table 20). Terna SA, the owner of the Italian high voltage national transmission grid, commissioned a total of three sodium nickel chloride ES systems within 2014–2015. The two larger systems of 1.2 MW and 4.15 MWh were purchased from FIAMM and were installed in 2014 ([3], Table 20) and in 2015 ([4], Table 20), respectively. The smaller system of 1 MW and 2 MWh was purchased from GE and installed in 2014 ([5], Table 20). The Terna battery systems showed 90% efficiency at the module level (DC-based) while the AC-based efficiency dropped to 77–79%. These installations are part of Terna's grid-scale battery storage pilot projects consisting in the evaluation and comparison of several pilot-scales systems of different technologies, which are tested on the Italian grid for a wide range of applications. The ZEBRA systems have been tested for frequency regulation, voltage support, black start, transmission support, and transmission upgrades due to the wind, as the ultimate goal of the project is to increase the security of electricity systems in the Sicily and Sardinia islands with the installation of storage systems for a total 40 MW capacity.[212]

The 1 MW/2 MWh ZEBRA energy system from GE installed in North Cape Canada in 2014 is being used to integrate wind generation from the 10 MW Wind R&D Park located at Wind Energy Institute of Canada facility ([6], Table 20). As such, the systems' main applications consist of renewables capacity firming and renewable energy time shift. The 1.6 MW/4.5 MWh system from FIAMM was installed in French Guiana in 2015 at the Toucan solar plant to improve the quality and reliance of energy delivery and by absorbing excess solar power and delivering it when needed ([2], Table 20). Finally, a 5 MW/10 MWh system from GE was

[211] FIAMM website. (Accessed May 4, 2019. https://www.fiamm.com/en/north-america/company/history/).
[212] U.S. DOE Global Energy Storage Database. (Accessed May 5, 2019. https://www.energystorageexchange.org/).

commissioned in 2015 in the Annobon Island off Equatorial Guinea. The system powers an island-wide microgrid to provide reliable power and supply enough electricity to handle all of the island energy demand in case of power failure. As such, the systems applications consist of grid-connected commercial reliability and quality, grid-connected residential reliability, and microgrid capability.

The Durathon battery production in New York was halted in 2015. “Durathon battery technology is well-suited for certain applications, but isn't cost effective enough compared to other battery technologies," said Horne, GE's spokesperson. [213] However in 2017, GE Technology Development transferred its technology and know-how to a joint venture with a Chinese entity, Chaowei Lvna, based in Zhejiang. The goal is to continue the research, production, and sale of the Durathon battery, targeting the electric vehicle market.[214]

The ZEBRA batteries provide desirable attributes however it is still an emerging technology. The GE 1 MW/2 MWh system currently in operation in Canada ([2], Table 20) was acquired for $3 million resulting in $3,000 per kW and $1,500 per kWh. More information is needed on actual costs. However, at this stage of development and commercialization, ZEBRA technology may not be competitive enough in terms of proven reliability, performance and cost.

Table 20 Selected sodium nickel chloride energy storage systems showing reference number used for discussion, location, project name, commissioning year, power and capacity rating, duration time, siting, business model and applications. [215]

Ref.	Location	Project Name	Paired Grid Resource	Commiss.	Power	Capacity	Duration	Siting	Business Model	Energy Storage Tech.	Applications
#				Year	MW	MWh	h:mm		Owner		
1	Equatorial Guinea, Annobon Island	Annobon Island Microgrid	5 MW PV	2014	5	10	2:00		Third-Party	GE Energy Storage	Grid-Connected Commercial (Reliability & Quality), Grid-Connected Residential (Reliability), Microgrid Capability
2	French Guiana, Montsinéry-Tonnegrande	EDF EN Guiana, Toucan Project	5 MW PV	2015	1.6	4.5	2:48		Utility	FIAMM Energy Technology	Renewables Energy Time Shift
3	Italy, Codrongianos	Terna Storage Lab 1, Sardinia		2014	1.2	4.1	3:27	Transmission	Utility	FIAMM Energy Technology	Frequency Regulation, Voltage Support, Black Start, Transmission Support, Transmission upgrades due to wind
4	Italy, Ciminna	Terna Storage Lab 2, Sicily		2015	1.2	4.1	3:27	Transmission	Utility	FIAMM Energy Technology	
5	Italy, Codrongianos	Terna Storage Lab 1, Sardinia		2014	1	2	2:00	Transmission	Utility	GE Energy Storage	
6	Canada, North Cape	Wind Energy Institute of Canada Wind R&D Park and Storage System for Innovation in Grid Integration	10 MW Wind	2014	1	2	2:00	Secondary Distribution	Customer	GE Energy Storage	Renewables Capacity Firming and Renewables Energy Time Shift

[213] Stanforth, L. 2019. “GE proclaims success, despite battery plant closure.” (*Times Union*. January 12, 2016. https://www.timesunion.com/tuplus-local/article/GE-proclaims-success-despite-battery-plant-6748205.php).
[214] J. Chlinder. 2017. “Patents and know-how power new GE move into China battery market.” (IAM. January 16, 2017. https://www.iam-media.com/patents/patents-and-know-how-power-new-ge-move-china-battery-market).
[215] U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).

Flow batteries

The singularity of flow batteries is that the electroactive species are dissolved in non-flammable liquid electrolytes stored in tanks external to the battery reaction core. This enables isolation of these components allowing unparalleled flexibility in power/energy design. During operation, the electrolytes are pumped to the battery core that consists of two liquid electrode flow compartments separated by an ion selective membrane. During charge, an anolyte is reduced at the negative electrode while the catholyte is oxidized at the positive electrode. The reaction is reversed upon discharge.

While the NASA developed the flow batteries in the 1970's as ES for long-term space flights, they have received a new wave of interest thanks to their potential benefits in scaled grid applications.[216] This is in spite of the obvious limitations related to the more complicated mechanical system requirements compared to conventional batteries to maintain uniform pressures and avoid reactant mass transfer drop.

The most significant benefit of the flow battery design is the decoupling of power and energy. Indeed, the power is determined by the size of the electrodes in the cells as well as the number of cells that are stacked, while the energy is a function of the concentration and volume of the catholytes/anolytes. The system can easily allow the battery to be charged in parallel and discharged in series. The design is flexible, modular and scalable. Another advantage is the very low self-discharge when the electroactive species are stored in the external tanks. Finally, the system response is very fast, in the milliseconds if the system is idle, which increases to a few minutes if the system is completely off. Combined to the long duration capability of the flow cells, it offers the opportunity for a wide range of grid applications. By 2017 more than 322 MW had already been deployed worldwide.[217]

Flow batteries are categorized into redox flow batteries and hybrid flow batteries. All electroactive species are dissolved in the electrolytes in redox flow, while at least one of the electroactive species exist as a solid layer within the battery core in hybrid flow. While various redox couples have been investigated such as the zinc-iron, iron-chromium, the iron-titanium and the polysulfide-bromide, this report focuses on the more mature vanadium redox flow battery and the zinc bromine hybrid flow battery. [218, 219]

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216 International Electrotechnical Commission (IEC). 2011. "Electrical energy storage." (White paper https://www.iec.ch/whitepaper/energystorage/)
217 Ran Fu, Timothy Remo, and Robert Margolis. 2018. *2018 U.S. Utility-Scale Photovoltaics-Plus- Energy Storage System Costs Benchmark*. (Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71714. https://www.nrel.gov/docs/fy19osti/71714.pdf).
218 International Electrotechnical Commission (IEC). 2011. "Electrical energy storage." (White paper https://www.iec.ch/whitepaper/energystorage/)
219 X. Luo, J. Wang, M. Dooner, D. Clarke, "Overview of current development in electrical energy storage technologies and the application pltential in power system operation", Applied Energy, vol.137, p.511-536, 2015

Vanadium redox flow batteries

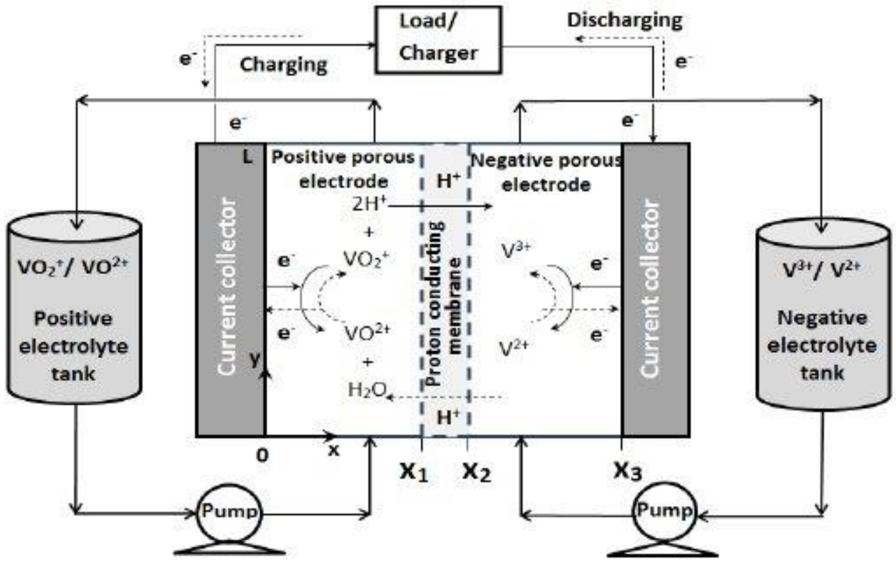

Figure 71: Working principles of a vanadium redox flow battery.[220]

The vanadium redox flow battery technology, pioneered at the University of New South Wales in Australia in the early 1980s and patented in 1986 (Figure 39), is the most mature and the most widely commercialized of all of the flow batteries. The uniqueness of this type of flow battery is that all electroactive species are based on vanadium in different valence state eliminating the risk of cross-contamination through a proton conducting membrane such as Nafion®. Indeed, metal ions crossing through the membrane cannot be completely suppressed would be detrimental to the system's performance if ions are from different metals.

The negative electrolyte (also called anolyte) consists of the V^{3+}/V^{2+} redox couple while the positive electrolyte (catholyte) is the VO_2^+/VO^{2+} associated to the V^{5+}/V^{4+} couple in a mild sulphuric acid solution. The acidity is similar to that of lead-acid batteries. During charge, the V^{3+} ions of the anolyte are reduced to V^{2+} ions at the negative electrode, and the VO^{2+} ions (associated to V^{4+}) of the catholyte are oxidized at the positive electrode into VO_2^+ (associated to V^{5+}) ions (Figure 71). Upon discharge, the reactions are reversed. Electrodes are porous and typically carbon based.

Technology:

The main drawbacks of the vanadium redox flow batteries are low specific energy (15–50 Wh/kg), energy density (20–70 Wh/L) and power density (0.5–2 W/L) due to the large volumes of electrolytes. However, if the large scale and large footprint of the system can be accommodated, flow cells offer many beneficial attributes as we have mentioned. The capacity and power can be decoupled providing flexibility and modularity to the technology. The

[220] C. L. Chen, H. K. Yeoh, M. H. Chakrabarti.2013. "An enhanced one-dimensional stationary model for the all-vanadium redox flow battery." (Proceedings of the 6th International Conference in Process Systems Engineering PSE ASIA), 25 - 27 June 2013, Kuala Lumpur, Malaysia, 2013).

technology also offers high cycle stability and long life. Cycle life is not correlated to depth of discharge; systems have been shown to sustain 13,000 cycles. The life of the system is limited by the cell stack at the core of the system with a 10–12 year lifespan. The external system structure including the pumps, tanks, power electronics and controls have a longer life. The vanadium-based electrolyte should have extremely long life and could eventually be reused with a new battery core, in addition the catholyte and anolyte can be replaced. [221]

The lower AC-efficiency of 65–70% is due to parasitic loss caused by the circulation of electrolyte that requires the use of pumps. Self-discharge is low (0.0–1.0% per day) and is associated to the loss of energy and heat generation in the cell stack when the electrolyte is left in the battery core. However, the battery core is usually elevated above the tanks and electrolytes drained to minimize self-discharge. Response time from this stated of inactivity with the pumped off and the stacks are drained is only a few minutes. If the pumps are idle and the stacks are already primed with electrolytes then the response time is much faster and reduced to a few milliseconds. However, maintaining the system in such idle state generates parasitic loss. The controls and communication systems are the limiting factors, they add to the complexity of the system. Risk of leakage is needs to be considered, robust and hermetic seals are needed to reduce maintenance and achieve long life.

Environmental Impact:

There is no established process yet to recycle vanadium flow cell batteries.[222] However, there is great interest to recycle the large volumes of electrolyte to be re-used in new systems.[223]

Case Studies:

Vanadium redox flow cells systems installed worldwide or under contract and construction in 2017 total 264 MW in rated power.[224] The selected systems listed in Table 21 have an average duration of 3.5 hours and rated power ranging from 500 kW to 200 MW. The five systems deployed in the United States included in Table 21 provide case studies of some of the highest rated power systems. The largest vanadium redox flow system in the United States is located at the Snohomish County Public Utility District substation in Everett, Washington. The system rated at 2 MW and 8 MWh ([8], Table 21) was the largest capacity containerized flow battery in the world at its commissioning in 2017. The system was manufactured by UniEnergy Technologies (UET) in Mukilteo, Washington. The system was designed and build with multiple containment systems within the Doosan container design. It was a conservative approach regarding environmental safety. As an emerging technology combined with a novel containerization design, this project consisted as a research and development project. As such,

[221] A. A. Akhil, G. Huff, A. B. Currier, B. C. Kaun, D. M. Rastler, S. Bingqing Chen, A. L. Cotter, D. T. Bradshaw, and W. D. Gauntlett. 2014. "DOE/EPRI Electricity storage handbook in collaboration with NRECA."(*Sandia Report, SAND2015-1002, September 2014*. https://prod-ng.sandia.gov/techlib-noauth/access-control.cgi/2015/151002.pdf)
[222] L. Unterreiner, V. Jülch and S. Reith.2016. "Recycling of battery technologies – Ecological impact analysis using life cycle assessment (LCA)." (*Energy Prcocedia*. 10th International Renewable Energy Storage Conference, IRES 2016, 15-17 March 2016, Düsseldorf, Germany).
[223] Patent Application CN106340657A, Method for recycling vanadium electrolytic solution
[224] DOE Global Energy Storage Database. 2019. https://www.energystorageexchange.org/

design and manufacture has taken longer on this project than on more mature technologies. [225,226] The system was paired with solar generation as such it is used for integration and stabilization of the renewable power source and peak shifting. It also manages transmission constraints, mitigates energy imbalances and serves as voltage support and load following. Finally it also participates in energy arbitrages.[227] A 1 MW/0.5 MWh Li-ion battery was also deployed at the same site and cost for both systems amounted to $15 million. The Washington State Department of Commerce's Clean Energy Fund provided $7 million in funding. The Public Utility District received an additional $1 Million from the Clean Energy Fund for a partnership with the Bonneville Power Administration and the University of Washington to optimize the use of energy storage and demand response.[228]

The only other MW-scale system in the United Stated is also located in Washington at the Washington State University in Pullman ([10], Table 21). The 1 MW/3.2 MWh system also manufactured by UniEnergy Technologies (UET) is owned by Avista Utilities and is used for load following, frequency regulation, conservation voltage regulation, energy time shift, supply reserve capacity on the distribution circuit in Pullman. The system is also reported to support Avista's customer Schweitzer Engineering Laboratories with power supply without interruptions and black start. As with the system in Everett, the Washington State Department of Commerce's Clean Energy Fund provided some funding for the project. Governor Inslee and the Washington State Department of Commerce's Clean Energy Fund contributed with $3.2 million and Avista provided $3.8 million in matching funds for a total of $7 million. [229] The Washington State has been actively supporting the deployment of utility-scale vanadium redox flow systems through its State Department of Commerce's Clean Energy Fund.

Finally, it seems that there is more interest in vanadium redox flow batteries for ES in the United States as the Canadian company CellCube, which develops and manufactures vanadium redox flow batteries, has announced in March 2019 that it had signed an agreement with an unnamed US based energy asset development company to manufacture up to 100 MW of ES for deployment in the U.S.[230] CellCube's president Stefan Schauss stated in December 2018 that the costs of its 4h-vanadium redox flow batteries might decrease by 50% within four years from

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[225] SnoPDU Mesa 2 Vanadium Flow Battery Fact Sheet. (Accessed May 10, 2019). https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=7&ved=2ahUKEwi05tqzlpHiAhWriOAKHRxUD8YQFjAGegQIBhAC&url=http%3A%2F%2Fwww.commerce.wa.gov%2Fwp-content%2Fuploads%2F2018%2F08%2FEnergy-MESA2-FactSheet_082418.docx&usg=AOvVaw3p_bebbuKrz5vO1yZp2_Sx).

[226] Energy Storage Association (ESA). 2017. "UET and Snohomish county PUD dedicate the world's largest capacity containerized flow battery." March 29, 2017. (Accessed May 09, 2019. http://energystorage.org/news/esa-news/uet-and-snohomish-county-pud-dedicate-worlds-largest-capacity-containerized-flow).

[227] SnoPDU Mesa 2 Vanadium Flow Battery Fact Sheet. (Accessed May 10, 2019. https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=7&ved=2ahUKEwi05tqzlpHiAhWriOAKHRxUD8YQFjAGegQIBhAC&url=http%3A%2F%2Fwww.commerce.wa.gov%2Fwp-content%2Fuploads%2F2018%2F08%2FEnergy-MESA2-FactSheet_082418.docx&usg=AOvVaw3p_bebbuKrz5vO1yZp2_Sx).

[228] Snohomish County Public Utility District No. 1, PUD Energy Storage Program. (Accessed May 10, 2019. https://www.snopud.com/PowerSupply/energystorage.ashx?p=2142).

[229] G. Meyers. 2016. "Avista utilities develops energy storage projects in Washington." (*Clean Technica*. March 15, 2016. https://cleantechnica.com/2016/03/15/avista-utilities-develops-energy-storage-project-washington/).

[230] CISION PR Newswire. 2019. "CellCube unveils 100 MW energy storage partnership in US." March 14, 2019. (Accessed April 14, 2019. https://www.prnewswire.com/news-releases/cellcube-announces-100-mw-energy-storage-project-in-us-300811704.html).

$300, potentially boosting its uptake over Li-ion batteries.[231] Navigant Research put flow batteries utility scale average installed costs for bulk energy storage services at approximately $550/kWh for 2018 expected to drop to $300/kWh by 2023 (Figure 43). [232]

Table 21: List of selected vanadium redox flow battery storage systems that are already installed or are under construction. The list presents a reference number used for discussion, location, project name, commissioning year, power and capacity rating, duration time, siting, business model, applications, and energy storage vendors. [233]

Ref.	Location	Project Name	Paired Grid Resource	Commiss.	Siting	Business Model	Power	Capacity	Duration	Ancillary Services					Bulk Energy Services		Renewable Integration Services			Customer Services	Energy Storage Tech.
#				Year		Owner	MW	MWh	h:mm	FR	Electric Supply Reserve Cap. - Spinning	Voltage Support	Black Start	Load Following	Electric Energy Time Shift	Electric Supply Capacity	Ramping	Renewable Energy Time Shift	Renewable Capacity Firming	Electric Bill Mngt	System / Battery
1	China, Liaoning, Dalian	Dalian Energy Storage		2019		Utility	200	800	4:00				✓		✓			✓	✓		UniEnergy Technologies (UET)/Rongke Power
2	Japan, Hokkaido, Abira-Chou	Minami Hayakita Substation (*Pilot Project - 3 years*)		2015		Utility	15	60	4:00										✓		Sumitomo Electric Industries (SEI)
3	China,Hubei, Zaoyang	Hubei Zaoyang 10MW/40MWh Storage Integration *Demonstration Project*	PV	Phase 1 completed 2018		Utility	10 (Phase 1 = 3)	40 (Phase 1 = 12)	4:00										✓		VRB Energy (Previously Pu Neng)
4	China,Liaoning, Shenyang	Guodian Longyuan Wind Farm VFB Storage Project	-	2013		Customer	5	10	2:00		✓	✓							✓		Rongke Power
5	Japan, Hokkaido, Tomamae	Tomamae Wind Farm	30.6 MW Wind	2005	Transmission	Utility	4	6	1:30									✓	✓		Sumitomo Electric Industries, Ltd.
6	Antigua and Barbuda, St John's	V.C. Bird International Airport of Antigua Solar/Energy Storage Project	3 MW PV	2015		Utility	3	12	4:00										✓		sun2live
7	Japan, Kansa, Osaka	Sumitomo Densetsu Office		2000		Customer	3	0.8	0:16											✓	Sumitomo Electric Industries, Ltd.
8	United States, WA, Everett	Snohomish County Public Utility District	605 kW PV	2017		Utility	2	8	4:00			✓		✓	✓				✓		UniEnergy Technologies (UET)
9	Canada, ON, Milton	IESO Flow Battery Milton Site		2018		Third-Party	2	8	4:00											✓	Cell Cube (formerly Gildemeister Energy Solutions)
10	United States, WA, Pullman	Washington State University Flow Battery Energy Storage		2015		Utility	1	3.2	3:12	✓	✓		✓	✓	✓						UniEnergy Technologies
11	United States, CA, Oxnard	Gills Onions Flow Battery Energy Storage		2012	Secondary Distribution	Third-Party	0.6	3.6	6:00						✓					✓	Prudent Energy Corporation
12	United States, WA, Mukilteo	UET HQ Mukilteo Energy Storage				Customer	0.6	1.8	3:00						✓						UniEnergy Technologies (UET)
13	United States, MA, Worchester	Holy Name High School Energy Storage	600 kW Wind	2018		Customer	0.5	3	6:00										✓	✓	Vionx Energy (formerly Premium Power)

KEPCO in cooperation with Sumitomo Electric Industries, Ltd. (SEI) started its effort on the development of redox flow batteries in 1985. SEI first installed its own 3 MW/0.8 MWh vanadium redox flow system at its headquarter in Osaka, Japan, in 2000 for electric management purposes ([7], Table 21). Then in 2005, SEI contracted by J-Power utilities installed a 4 MW/6 MWh system at the 30.6 MW Tomamae wind farm on the island of Hokkaido in Japan ([5], Table 21). The main goals were to integrate and smooth the wind generation and also provide time shifting. The system has been operating satisfactorily since its installation while performing at times over 50 charge-discharge cycles per hour. This case study illustrates that vanadium redox flow batteries demonstrate robustness with long cycle life and long lifetime of at least 8 years.[234] In 2015, Hokkaido Electric Power Co Inc. (HEPCO) and SEI completed the largest vanadium redox flow cell in Japan rated at 15 MW and 60 MWh ([2], Table 21). The system manufactured by SEI was installed at Minamihayakita Transformer Station in Abira-chou,

[231] F. Shen. 2018. "Canada battery maker says flow storage costs tumble by half." (*Bloomberg News.* December 23, 2018. Accessed April 15, 2019. https://www.bloomberg.com/news/articles/2018-12-24/canada-battery-maker-says-flow-storage-costs-to-tumble-by-half).
[232] Bushveld Minerals. 2018 "Energy storage & vanadium redox flow batteries 101." (November 13, 2018. Accessed April 26, 2019. http://www.bushveldminerals.com/wp-content/uploads/2018/11/Energy-Storage-Vanadium-Redox-Flow-Batteries-101.pdf).
[233] U.S. DOE Global Energy Storage Database. 2019. (https://www.energystorageexchange.org/)
[234] U.S. DOE Global Energy Storage Database. "Tomamae wind farm." (Accessed May 09, 2019. https://energystorageexchange.org/projects/1031).

Hokkaido. The pilot project was expected to last three years. The main goals were to test the system performance when used to adjust the output fluctuation of wind and solar power generation facilities and develop optimal control technologies.[235]

Many smaller size systems have been installed in China however only the largest ones have been listed in Table 21. VRB Energy, formerly known as Pu Neng, completed phase one of the 10 MW/40 MWh Utility-Scale Solar and Storage Integration Demonstration Project in Hubei, Zaoyang, at the end of 2018 ([3], Table 21). Phase one consisted in the commissioning of the system rated at 3 MW/12 MWh. The system will be tested in the integration and stabilization of solar power generation.[236] When the 10 MW/40 MWh project is finalized the Hubei Province has already planned a larger 100 MW/500 MWh project to fulfill China's 2017 energy storage policy to deploy multiple 100 MW-scale vanadium flow batteries.[237] A 200 MW/800 MWh system is currently under construction in the Liaoning province in Dalian ([1], Table 21). UniEnergy Technologies and Rongke Power are collaborating on the project.[238] The system will consist of an array of ten batteries of 20 MW/80 MWh as approved by the China National Energy Administration. The flow batteries are being manufactured at Rongke Power's GigaFactory, which opened nearby in 2016. The system is supposed to commence operation in 2020 and will become the largest energy storage system in the world. The purpose of the system is to integrate renewable power source and time shift, improve grid stabilization and provide black start in case of grid failure.[239]

If footprint is not an issue, the vanadium redox flow battery technology provide great potential in terms of performance and it will become more competitive in cost once it will become more mature.

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[235] U.S. DOE Global Energy Storage Database."Minami Hayakita substation Hakkaido electric power- Sumitomo." (Accessed May 09, 2019. https://energystorageexchange.org/projects/1451).

[236] VRB Energy. 2019. "VRB Energy completes commissioning of phase 1 of the Hubei Zaoyang 10 MW/ 40 MWh utility-scale salar and storage integration demonstration project." (*Global Newswire.* January 11, 2019. Accessed May 09, 2019 https://www.globenewswire.com/news-release/2019/01/11/1690630/0/en/VRB-Energy-Completes-Commissioning-of-Phase-1-of-the-Hubei-Zaoyang-10MW-40MWh-Utility-Scale-Solar-and-Storage-Integration-Demonstration-Project.html).

[237] Market Watch. 2018."VRB Energy commissions 3 MW 12 MWh vanadium redox battery energy storage system (VRB-ESS(R)) in phase 1 of the Hubei Zaoyang 10 MW 40 MWh utility-scale solar and storage integration demonstration project." (*Market Watch*. October 31, 2018. Accessed May 09, 2019. https://www.marketwatch.com/press-release/vrb-energy-commissions-3mw-12mwh-vanadium-redox-battery-energy-storage-system-vrb-essr-in-phase-1-of-the-hubei-zaoyang-10mw-40mwh-utility-scale-solar-and-storage-integration-demonstration-project-2018-10-31).

[238] UniEnergy Technologies. 2019. "UniEnergy Technologies strategic partner to deliver world's largest battery." *Uetechnologies.* May 31, 2016. Accessed February 02, 2019.http://www.uetechnologies.com/news/72-unienergy-technologies-strategic-partner-to-deliver-world-s-largest-battery).

[239] J. Fitzgerald Weaver, 2017. "World's largest battery: 200 MW / 800 MWh vanadium flow battery – site work ongoing" (*Electrek*. December 21, 2017. Accessed February 4, 2019. https://electrek.co/2017/12/21/worlds-largest-battery-200mw-800mwh-vanadium-flow-battery-rongke-power/).

Zinc bromine redox flow batteries

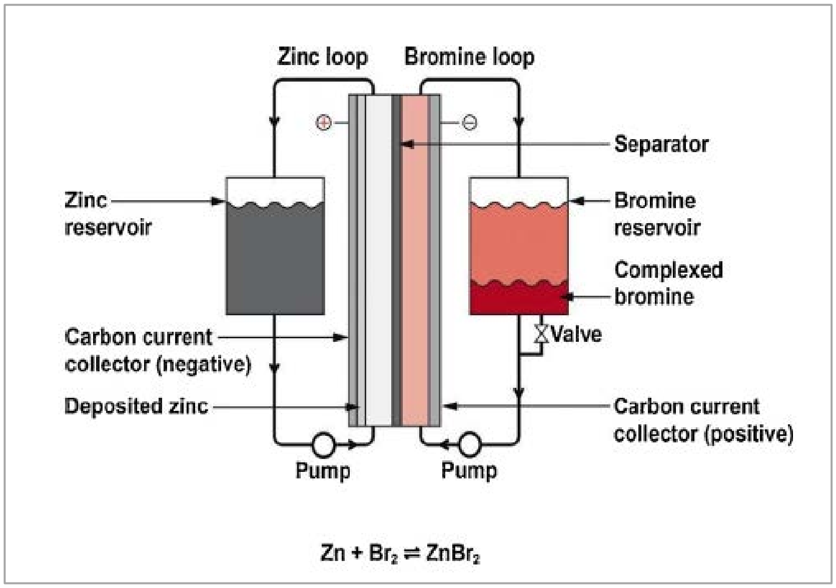

Figure 72: Schematics of zinc-bromine flow battery.[240]

The hybrid zinc-bromine flow battery consists of a non-flammable catholyte and anolyte stored in external reservoirs and a battery core separated into a positive and negative electrode compartment by a microporous plastic separator (Figure 72). During operation the electrolytes based of aqueous solutions of zinc bromide ($ZrBr_2$) flow through the battery electrodes. The direction of the electrolytes flow streams varies with the design. During charge, the zinc ions Zn^{2+} reduce, and deposit at the surface of the negative electrode, while the bromide ions Br^- oxidize to form bromine. During discharge, the zinc dissolved back into the anolyte, and reactions are reversed.

Technology:

The concept of a flow battery based on the zinc/bromine couple was patented over 100 years ago in 1885.[241] However, its commercialization has been stalled by the formation of dendrites at the surface of the zinc deposition layers at the surface of the negative electrolyte and the high solubility of bromine in the aqueous zinc bromide electrolyte. Dendritic zinc deposits could easily short-circuit the cell, and the high solubility of bromine facilitates diffusion and direct reaction with the zinc electrode, resulting in self-discharge of the cell. The microporous separator, which allows for free flow of ions, stops (or at least minimizes) the zinc/bromine cross-contamination and it also impedes the progression of zinc dendrites. Complexing agents are added to the electrolyte, which bind to available bromine to form a low-solubility secondary liquid-phase. Maintaining circulation of the electrolytes 1) expedites the transport of bromine-complex away from the electrode to the reservoir during charge freeing the surface area for

[240] G. J. May, A. Davidson, and B. Monahov. 2018. " Lead batteries for utility energy storage: A review." (*Journal of Energy Storage*. vol. 15, p. 145-157).
[241] International Electrotechnical Commission (IEC). 2011. "Electrical energy storage. (White Paper https://www.iec.ch/whitepaper/energystorage/).

further reaction, and from the reservoir back to the electrode during discharge, 2) mitigates the deleterious tendency for dendrites growth, and 3) enables for ease of thermal management. A heat exchanger located in the negative electrolyte reservoir typically provides the temperature management system required.[242, 243]

Similarly to the vanadium flow cell, there is extreme flexibility in the design. Power and energy are decoupled. While systems are typically manufactured with low cost readily available thermoplastics and electrodes are made of carbon plastic to resist the corrosive bromine environment, [244] vendor designs may differ. Primus Power offers a single tank design with no membrane and titanium electrodes that should more durably endure the corrosive electrolyte over time. The Australian company Redflow focuses on readily available and low cost components with plastic tanks.[245]

The flow zinc-bromine flow battery operates at ambient temperature, however, some vendors provide cold weather packages for operation (most likely limited) down to -30°C.[246] Although its specific capacity (75-85 Wh/kg) is higher than vanadium redox flow, Ni-Cd, and lead-acid, it remains relatively lower than Li-ion and high-temperature batteries. However, its energy density (65 Wh/L) is similar to that of the vanadium flow battery, but is significantly lower than that of Li-ion and high-temperature batteries due to the large volume of the electrolytes. Power density is low at 1-25 W/L but seems adequate for most applications.

The system can sustain 100% discharge and is capable of rapid charge. The system provides rapid response in the milliseconds. Typical AC-efficiency is in the 60-70% range. During standby operation, energy losses originate from the pumps necessity to function for the electrolytes to circulate and minimize cross-contamination and thereby self-discharge (<1%).[247] System failure is related to bromine corrosion; as such it is more a function of time of operation rather than cycle number and depth of discharge. Some vendors claim up to 30,000[248] cycles and 10 to 20-year lifetime[249], but all are dependent on the application. And some offer 10-year warranty.[250]

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[242] A. A. Akhil, G. Huff, A. B. Currier, B. C. Kaun, D. M. Rastler, S. Bingqing Chen, A. L. Cotter, D. T. Bradshaw, and W. D. Gauntlett. 2014. "DOE/EPRI Electricity storage handbook in collaboration with NRECA." (Sandia Report, SAND2015-1002, September 201. https://prod-ng.sandia.gov/techlib-noauth/access-control.cgi/2015/151002.pdf).

[243] Linden, David and Thomas B. Reddy. 1995. *Handbook of Batteries*. Third Edition. McGraw-Hill, 1995.

[244] Linden, David and Thomas B. Reddy. 1995. *Handbook of Batteries*. Third Edition. McGraw-Hill, 1995.

[245] A. Colthorpe. 2018. "Long time coming: Part 2." (*Energy Storage News*, October 2, 2018. https://www.energy-storage.news/blogs/long-time-coming-part-2).

[246] EnSync Energy Systems. "Agile Flow Battery Product Data Sheet." (Accessed May 11, 2019. https://docs.wixstatic.com/ugd/4f852c_7945822093134e9a9927645aa3fe1903.pdf).

[247] K. Bradbury. 2010. "Energy storage technology review." August 2010. (https://www.kylebradbury.org/docs/papers/Energy-Storage-Technology-Review-Kyle-Bradbury-2010.pdf).

[248] Primus Power. 2017. "How advances in long duration, low cost, energy storage are making possible the creation of self-sufficient, high resilience microgrids." August 2017. (Accessed May 11, 2019. http://www.primuspower.com/assets/pdf/Self-Sufficient-High-Resilience-Micro-Grids.pdf).

[249] Battery International. 2017. "Primus Power launches second-generation zinc bromine flow battery." February 22, 2017. (Accessed May 11, 2019. http://www.batteriesinternational.com/2017/02/22/primus-power-launches-second-generation-zinc-bromine-flow-battery/).

[250] Redflow. "ZBM2 zinc-bromine flow battery." (Accessed May 11, 2019. https://redflow.com/products/redflow-zbm2/).

Environmental Impact:

Bromine exists as polybromide ions dissolved in the aqueous electrolyte or bound to complexing agents in a low-solubility secondary liquid-phase in the electrolyte. While bromine is hazardous in the liquid or gaseous phase, its chemical reactivity and evaporation rate are greatly reduced in the complexed form. The electrolyte is not consumed during operations. As such it can be retrieved and recycled by being reused in other batteries.

Most parts of the battery consist are made of plastic and can be recycled by conventional processes. If high value titanium electrodes are utilized, they can be retrieved and also recycled. In short, the hybrid zinc-bromine flow cell is made of re-usable/recyclable components, which have low environmental impact. [251]

Case Studies:

Exxon and Gould jump-started the research and development of the hybrid zinc-bromine flow batteries in the mid 1970's and early 1980's. While they some progress Exxon licensed its zinc-bromine technology to several entities worldwide in the mid 1980's. There are currently several vendors and the technology has already been deployed in the field in demonstration trials and commercial sales. RedFlow with its 10 kW ZM2 product targets the industrial, commercial and residential sectors. In contrast, both Primus Power with its 25 kW EnergyPod®2 module and EnSync with its 25 kW Agile battery aim at serving a wider range of applications including large-scale grid.

The selected installations in Table 22 range from 0.25 kW to 1 MW in power and 0.5 to 2 MWh in energy. These case studies demonstrated the ability of zinc-bromine flow batteries to integrate, time shift and stabilize renewable power sources. In Bellevue (Washington), the 500 kW/1 MWh system is located at a substation to defer T&D capacity, increase reliability, and add system flexibility ([4], Table 22). Demonstration trials were also performed at two DOD stationary bases that are adopting microgrids to sustain operations independent of the utility grid ([6] & [8], Table 22). In addition to the capabilities that we have previously described in pairing with renewable power sources, the system provides black start support. For customer-owned systems such as shown in reference ([5], Table 22), the zinc-bromine flow battery can provide electric bill management. In short, the zinc-bromine flow technology can serve many applications and in different markets such as behind-the-meter, commercial and industrial, and utility energy storage.

The main issue presently slowing down further penetration of the zinc-bromine technology as stated by people close to the subject is its lower bankability compared to Li-ion, which has been used in many other applications before being utilized in utility-scale energy storage. Vendors lack proof of durability due to the novel technology/products. As such stakeholders' lack confidence in the product and request insurances. For instance, ESS Inc. is working on getting its systems insured. Primus Power is also actively working on its bankability. Its technology has been reported to have already received a favorable bankability study by the infrastructure group Black & Veatch. Primus Power is also seeking a warranty backstop as well

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[251] Linden, David and Thomas B. Reddy. 1995. *Handbook of Batteries*. Third Edition. McGraw-Hill, 1995.

as a revenue assurance protection product from two other companies.[252]

In terms of costs, the Redflow customer-owned behind-the-meter installation rated 0.3 MW/0.66 MWh commissioned in 2015 in Australia amounted to $1 million resulting in $3,333 per kW and $1, 515 per kWh ([5], Table 22). Commercial and industrial, and utility-scale costs per unit of energy are expected to be lower. However, the zinc-bromine technology is still at its early commercialization stage and therefore costs are expected to decrease as manufacturing capacity increases, particularly since the systems are made of low-cost materials, as long as the Li-ion technology does not overcrowd the markets and keeps new technologies at bay.

Table 22: Selected hybrid zinc flow batteries showing reference number used for discussion, location, project name, commissioning year, power and capacity rating, duration time, siting, business model, applications, and energy storage vendors.[253]

Ref.	Location	Project Name	Paired Grid Resource	Commiss.	Siting	Business Model	Power	Capacity	Duration	Ancillary Services					T & D Services	Bulk Energy Services		Renewable Integration Services			Customer Services	Energy Storage Tech.
#				Year		Owner	MW	MWh	h:mm	FR	Electric Supply Reserve Cap.	Voltage Support	Black Start	Load Following	T&D Upgrade Deferal	Electric Energy Time Shift	Electric Supply Capacity	Ramping	Renewable Energy Time Shift	Renewable Capacity Firming	Electric Bill Mngt	System / Battery
1	French Polynesia, Tahiti,Tetiaroa	Tetiaroa Brando Resort	896 kW PV	2013	-	Customer	1	2	2:00											✓		EnSync Energy Systems
2	United States,MA, Everett	Distributed Energy Storage Systems Demonstration (Everett, MA)	605 kW PV	2016	-	Utility	0.5	3	6:00			✓				✓				✓		Vionx Energy (formerly Premium Power)
3	United States,MA, Worcester	Distributed Energy Storage Systems Demonstration (Worcester, MA)	600 kW Wind	2016	-	Utility	0.5	3	6:00			✓				✓			✓	✓		Vionx Energy (formerly Premium Power)
4	United States, WA, Bellevue	PSE Bellevue Storage Innovation Project		2012	Primary Distribution	Utility	0.5	1	2:00		✓				✓			✓				Primus Power
5	Australia, SA, Adelaide	RedFlow 300 kW Adelaide	PV	2015	-	Customer	0.3	0.66	2:12		✓										✓	Redflow
6	United States, OK, Fort Sill	Fort Sill Microgrid - Eaton Corporation	2.5 kW Wind, 30 kW PV, 400 kW NG		-	Customer	0.25	0.5	2:00											✓		EnSync Energy (formerly ZBB Energy Corporation)
7	United States, IL, Chicago	Illinois Institute of Technology RDSI Perfect Power Demonstration		2014	-	Customer	0.25	0.5	2:00				✓									EnSync Energy (formerly ZBB Energy Corporation)
8	United States, CA, San Diego	DOD Marine Corps Air Station Miramar Microgrid Energy Storage System	230 kW PV	2015	Secondary Distribution	Customer	0.25	1.0	4:00				✓							✓	✓	Primus Power
9	United States, CA, Modesto	MID Renewables Firming Wind Energy Storage Demonstration		2015	Secondary Distribution	Third-Party	0.25	1.0	4:00										✓			Primus Power

[252] A. Colthorpe. 2018. "Long time coming: Part 2." (*Energy Storage News*. October 2, 2018. https://www.energy-storage.news/blogs/long-time-coming-part-2).
[253] U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).

Electrical chemical energy storage

This analysis of chemical energy storage focuses on hydrogen fuel cell energy storage.

Hydrogen fuel cell energy storage

Hydrogen fuel cell energy storage is an emerging technology, which consists of the storage of energy in the form of hydrogen, produced by water electrolysis. Regenerative fuel cells can be used to convert the chemical energy stored in hydrogen and oxygen from air to generate electricity. In spite of low efficiencies, the hydrogen energy storage is scalable, from distributed to large-scale, and is suitable for long-term (even seasonal) storage. These systems have the potential to participate in ancillary services, integrate variable renewable power sources, serve as reserve for the grid system, and provide mobility energy storage. The technology is still in developmental still developmental stage, and the 2017 global installed capacity amounted to 8.9 MW and 100 MWh, with an average duration of 11.2 hours.[254]

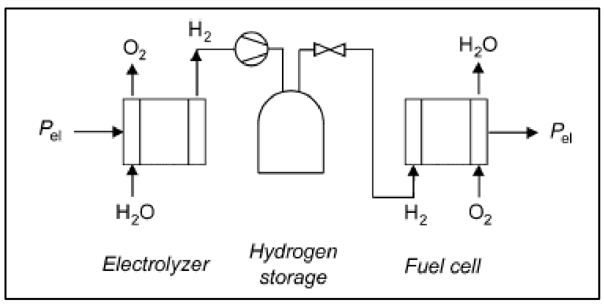

Figure 73: Schematic of a regenerative hydrogen fuel cell system.[255]

A hydrogen fuel cell energy storage system typically consists of an electrolyzer, a hydrogen storage tank and a fuel cell (Figure 73). To store energy (charge), electricity powers the electrolyzer, which is an electrochemical converter, using electricity to the splits water into hydrogen and oxygen. Since the reaction is endothermal, the process also requires heat. The released hydrogen is compressed and stored under pressure in gas bottles or tanks. To generate electricity (discharge), both gases flow into the fuel cell where hydrogen and oxygen electrochemically react to produce water, release heat released and generates power. Oxygen is not stored but vented to the atmosphere for practical and economic reasons. For economic and practical reasons, the oxygen source and outlet is atmospheric air.[256]

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[254] Ran Fu, Timothy Remo, and Robert Margolis. 2018. *2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark*. (Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71714. https://www.nrel.gov/docs/fy19osti/71714.pdf).

[255] M. A. Pellow, C. J. M. Emmott, C. J. Barnhart, and S. M. Benson. 2015. "Hydrogen or batteries for grid storage? A net energy analysis." (*Energy & Environmental Science*. 8, 1938-1952, 2015).

[256] International Electrotechnical Commission (IEC). 2011."Electrical Energy Storage Whitepaper." (*IEC White Papers and Technology Reports*. https://www.iec.ch/whitepaper/energystorage/).

Technology:

Systems are flexible and can offer power and energy decoupling. The main drawback of hydrogen fuel cell energy storage is its low round trip efficiencies (35–45%), and safety concerns. Energy densities, based on the hydrogen tank storage, range within 30 to 2,550 Wh/L.[257] Power densities vary within 0.2 to 20 W/L, depending on system configuration. Hydrogen systems discharge times can last from minutes up to weeks. Reactions times vary within seconds to minutes. Systems' expected lifetime range between 10 and 30 years.

Environmental Impact:

Hydrogen fuel cell energy storage has little detrimental environmental impact. However, palladium metal catalysts in the fuel cells need to be recycled.

Case Studies:

The first utility-scale demonstration project was developed in 2004 on Utsira Island, Norway. The hydrogen energy storage system, which was owned by Statoil ASA (now Equinor ASA), but was operated by Enercon, manufacturer wind turbine of the 600 kW wind farm paired with the hydrogen storage system to generate continuous power to the island residents. The project goal to demonstrate how renewable energy, in this case, hydrogen paired with wind, can provide a safe, continuous, and efficient energy supply to remote areas. System operated successfully for four years, with good power quality, and in stand-alone mode at 50% of the time. However, energy utilization was only 20% revealing the need for advances in electrolyzers' efficiency and hydrogen-electricity-conversion efficiency. In addition, the fuel cell device suffered rapid degradation when idle and was operated for less than 100 hours over the duration of the project. At the end of the project in 2008, the stakeholders believed the frame to be competitive with conventional remote-site power supplies, such as diesel or combined wind and diesel generators, to be about five to 10 years. [258]

The INGRID demonstration project commissioned at the end of 2016,[259] in Puglia, Italy, aims at combining Smart Grids and hydrogen-based energy storage to optimize local energy consumption, reduce power network congestion, and minimize energy curtailing from renewable energy power sources, while maintaining power distribution network stability and reliability. The consortium designed and installed a 1.2 MW/39 MWh hydrogen energy storage facility of advanced and improved performance, using McPhy hydrogen-based solid state storage and Hydrogenics electrolysis technology and fuel cell power systems, where over 3,500 MW of solar, wind, and biomass are already installed.[260] Similarly, the Hybalance demonstration project, which started operation in 2017, in Hobro, Denmark, is a1.2 MW systems that also generated hydrogen from wind generation.

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[257] European Association for Storage of Energy. Energy Storage. Hydrogen. (Accessed May 19, 2019. http://ease-storage.eu/wp-content/uploads/2016/07/EASE_TDs.pdf).

[258] IPHE Renewable Hydrogen Report. 2011. "Utsira wind power and hydrogen plant." (March 2011. http://www.newenergysystems.no/files/H2_Utsira.pdf).

[259] Ingrid McPhy. "A sold-state hydrogen storage solution with a total capacity of 750 kg." (Accessed May 21, 2019. https://mcphy.com/en/non-classe-en/ingrid/).

[260] Ingrid. (Website. http://www.ingridproject.eu/).

Hydrogen energy storage also provides some potential in mobile applications. In 2013, the U.S. Naval Air Warfare Center Weapons Division evaluated trailer-mounted hydrogen fuel cell system and an array of solar panels that can be towed behind ground vehicles and generate about 5 kW of electricity. Tests were performed at the China Lake Naval Air Weapons Station, in the high Mojave Desert, where solar output is high.[261]

Hydrogen energy storage has been successfully demonstrated at the utility-scale and it has also been evaluated for mobile applications. Technologic advances and lower costs are required for a deployment at the commercial stage.

[261] J. Keller. 2013. "Navy to field-test hydrogen fuel cell- and solar- powered military renewable energy systems." (*Military & Aerospace Electronics*. March 1, 2013. Accessed May 21, 2019. fhttps://www.militaryaerospace.com/power/article/16715236/navy-to-fieldtest-hydrogen-fuel-cell-and-solarpowered-military-renewable-energy-system).

Element 4

Consider the benefits and costs to ratepayers, local governments and electric public utilities associated with the development and implementation of additional energy storage technologies.

Summary of Findings

- Up-to-date data on capital costs for ES is sparse, especially for New Jersey, and thus there is significant uncertainty surrounding estimates of future deployment and cost scenarios.
- At present, costs of Li-ion ES for resiliency purposes remain high relative to their potential benefits. However, optimal sizing of batteries can result in significant resiliency benefits at relatively lower costs.
- Standalone (i.e., not coupled with PV) Li-ion installations for resiliency purposes would likely require subsidies or incentives of over $750,000-$1.2 million/MW of installed capacity for 4-hour duration batteries.
- The benefits of ES for resiliency purposes vary widely across facility types.
- Under the current PJM generation mix, use of Li-ion batteries in small-scale standalone installations could result in slight increases to CO_2 and other emissions.
- The value of outage avoidance enabled by ES can be significant, especially when batteries are optimally sized.
- Coupling Li-ion storage with PV *can* result in cost reductions via access to federal tax incentives, and enhance the benefits of the coupled ES. This can result in a reduction of necessary subsidies required for facility resiliency installations by as much as 60% relative to standalone ES. Under these conditions, investments in ES appear significantly more viable. In the short-term, costs would be minimized by taking advantage of the federal ITC, available for ES when coupled with PV, which declines from 30% to 26% in 2020, to 22% in 2021, and 10% after that.
- Li-ion storage costs are projected to decline sharply between 2020 and 2030, by between 26% and 45%.
- Investments in ES for wholesale market operations (i.e., frequency regulation and price arbitrage) appear to be commercially viable and would only require incentives under very high capital cost scenarios.
- The amount of “optimal” ES to be installed depends on the uses of the ES and the goals of its deployment.
- Declining cost trajectories for ES technology and the coming reduction of the ITC suggest that a phased strategy for investments in ES may be economically viable for New Jersey.
- We find that allocating ES (with PV) capacity across facility types produces the most efficient results (i.e., lowest required subsidies) when based on BCRs that account for the value of avoided outages.
- Depending on actual capital costs and optimal battery sizing, we estimate that deployment of 600 MW of Li-ion storage for resiliency applications in 2020 would require a subsidy of between $430 million and $1 billion for installations without PV, and

between $140 million and $650 million for installations with PV. The estimated value of avoided outages would be approximately $112.6 million for standalone ES and $105 million when coupled with PV in our base case, but these values could be significantly higher if batteries are optimally sized.

- For distribution network level applications where ES is deployed to allow for maximization of PV investment, we find that in the cases we tested, optimal ES size is smaller when PV+ES resources are distributed at the node level rather than centralized at the substation level. This results in higher benefit cost ratios and less negative net present values than in the centralized cases, as well as similar avoided outage values.
- The enhanced PV deployment in these cases does result in an increased value of avoided emissions as additional zero-emission PV generation offsets grid-generation emissions; however; we note again that under the current PJM resource mix, if the Li-ion batteries are not charging primarily from PV, they may be marginally increasing emissions. With the reduced emission and avoided outage benefits, we find that coupling of PV and ES at the node level may present an opportunity for targeted incentives.

Analysis and Discussion

This section includes cost-benefit-analysis (CBA) for facility level, distribution network, and bulk level applications of ES.

Facility Level Applications

The first set of CBA examined the installation of a 1 MW (normalized) 4-hour Li-ion battery at customer sites, in both standalone and PV-paired configurations for resiliency. For the standalone base case with no PV, we conducted a sensitivity analysis of BCRs and NPVs to changes in financial parameters. The CBA also considered stacked up applications (i.e., resilience and EBM).

Case #1: Standalone Li-ion Battery Storage

In the base case, we compare the benefits and costs of 1 MW, 4-hour Li-ion standalone battery storage for resiliency back-up power at individual facilities.

- Battery Size: 1 MW
- Battery Duration: 4-hour
- Year: 2020
- ITC: Does not apply where no renewable generation is present
- Depreciation: 7-year MACRS

We use low, medium and high-cost estimates from 2017/2018, de-escalated to 2020 using low, moderate and high-cost de-escalation trajectories.[262] The costs in these examples represent the low, medium and high estimates derived from the moderate cost de-escalation scenario.

The low-end capital expenditure cost estimate for Li-ion batteries represents the per-kW cost for a utility-scale 60 MW standalone Li-ion storage installation modeled by NREL.[263] The high-end cost estimate is derived from estimated project costs for a 4-hour, 1 MW Li-ion battery installation for peak reduction at public sector facilities reported in regulatory filings for PSE&G's Clean Energy Future-Electric Vehicle and Energy Storage Program.[264] The midpoint cost estimate represents the average of the low and high estimates. These midpoints have been compared to and are generally consistent with a range of other Li-ion battery capital expenditure estimates gleaned from an extensive literature review (see the Technology Section and Appendix C -Element 3: Supporting Materials). Annual fixed O&M costs for all scenarios are set at \$10/kW/year.[265]

Table 23 provides the NPV, BCRs, as well as the net value of avoided emissions and the value of avoided outages for six facility types based on their calculated EBM benefits (demand charge and energy cost reductions) and the mid-range estimate of capital expenditures. Table 24 provides more detailed data for each facility, with benefits, adjusted costs, BCRs and NPVs for the range of CapEx estimates for each facility.

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[262] In the de-escalation series taken from JRC (2018), the de-escalation from 2017-2020 is slightly faster in the moderate case than in that of the high case, though the "high" scenario de-escalates faster in later years. We have adjusted the high de-escalation case for 2018-2020 using data from Bloomberg to reflect an accelerated short-term de-escalation rate in the high de-escalation rate scenario. All other rates are derived from JRC (2018), Table 15.

[263] Ran Fu, Timothy Remo, and Robert Margolis. 2018. *2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark*. (Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71714. https://www.nrel.gov/docs/fy19osti/71714.pdf).

[264] Matthew M. Weissman. 2018. "In the matter of petition of Public Service Electric and Gas Company for its approval of its Clean Energy Future-Electric Vehicle and Energy Storage ("CEF-EVES") Program on a regulated basis." (General State Regulatory Counsel. Law Department PSE&G Services Corporation. Petition sent to NJ Board of Public Utilities. Oct 11, 2018). https://nj.pseg.com/aboutpseg/regulatorypage//media/6EA1F476B43F4BCBAB7D5F7A46E19DF7.ashx)

[265] Estimate based on figures cited in prior studies, which find ranges of \$6-\$14/kW/yr. See, for example: Todd Aquino et al. 2017. *Energy Storage Technology Assessment.* (Prepared for Public Service Company of New Mexico by HDR Inc. HDR Report No. 10060535-0ZP-C1001 https://www.pnm.com/documents/396023/1506047/11-06-17+PNM+Energy+Storage+Report+-+Draft+-+RevC.pdf/04ca7143-1dbe-79e1-8549-294be656f4ca); and Michael Kleinberg. 2016. *Battery Energy Storage Study for the 2017 IRP,*. Prepared by DNV GL for Pacificorp. DNV GL- Document No.: 128197#-P-01-A (http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/10018304_R-01-D_PacifiCorp_Battery_Energy_Storage_Study.pdf).

Table 23: Lifetime NPV, BCR, Net Emissions and Value of Avoided Outages for Facility Resiliency – Standalone ES.

	Net Present Value	Benefit-Cost Ratio	Net Avoided Emissions*	Value of Avoided Outages	NPV w/ Emissions and Avoided Outages
Hospital	-\$1,278,944	0.19	-\$34,094	\$379,452	-\$933,587
Apartment Complex	-\$1,254,890	0.21	-\$20,054	\$937	-\$1,274,008
Hotel	-\$1,214,478	0.25	-\$25,265	\$47,388	-\$1,192,355
Office	-\$1,238,011	0.23	-\$33,276	\$90,527	-\$1,180,760
Secondary School	-\$1,245,814	0.22	-\$21,890	\$17,125	-\$1,250,580
Supermarket	-\$1,265,102	0.20	-\$32,459	\$337,021	-\$960,540

* Avoided emissions include CO_2, SO_2 and NO_2. Negative dollar amounts indicate net increases in emissions.

In the absence of PV, variations in lifetime costs across facility types are minimal, resulting only from the extent to which energy cost and demand charge reductions result in increases to estimated future taxable operating surplus. All NPVs are in the range of -\$1.21 million to -\$1.28 million, with BCRs ranging from 0.19 for hospitals to 0.25 for hotels.

Net emissions of CO_2, NO_2 and SO_2 increase in these scenarios, as batteries are generally assumed to charge during off-peak hours and discharge during on-peak hours. Marginal emissions of CO_2 and SO_2 from the PJM grid are slightly higher during off-peak hours than during on-peak hours, while emissions of NO_2 are slightly lower.[266] Coupled with the 85% efficiency rate of the battery, this results in net increases in emissions when charging from the grid given the current mix of power generation technologies. See the discussion of Resiliency Base Case #2 (with PV) below for a discussion of longer-run net emissions.

The Value of Avoided Outages assumes three short-duration (1-3 hours) outages per year for each facility.[267] The amount of lost load avoided is calculated based on simulations presented previously in the Technical Approach. Based on EIA SAIFI index data for 2017, the average New Jersey energy customer experiences less than one outage per year. Thus, even under this conservative assumption of higher than expected Value of Avoided Outages, standalone ES at the facility level does not reach financial viability (see final column of Table 24), though significant lost load value may be captured in some cases. We tested the sensitivity of the BCRs and NPVs to changes in several parameters.

[266] PJM. 2013-2017 CO2, SO2 and SO2 Emission Rates. PJM. March 2018. https://www.pjm.com/-/media/library/reports-notices/special-reports/20180315-2017-emissions-report.ashx?la=en).
[267] ES in the absence of PV does not cover longer-term outages.

Table 24: Resiliency base cases: Energy Storage with No PV.

Battery Size:	1 MW	
PV Size:	No PV	
Battery Duration:	4 Hours	
Year:	2020	
ITC:	N/A	ITC does not apply where there is no associated PV
Depreciation:	7-Year MACRS	
Cost De-Escalation Scenario:	Moderate	
Discount Rate:	10%	
Annual Operating Costs:	$10/kW/yr	
Blended Tax Rate:	28.1%	
Availability	96.0%	
Efficiency:	85.0%	

Facility:	Hospital			Apartment Complex			Hotel			Office			Secondary School			Supermarket		
CapEx Level:	Low	Mid-Range	High	Low	Mid-Range	High	Low	Mid-Range	High	Low	Mid-Range	High	Low	Mid-Range	High	Low	Mid-Range	High
Capex/kW	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640
Lifetime Adjusted Costs (CapEx + OpEx)*	$1,046,200	$1,581,919	$2,118,435	$1,056,160	$1,591,878	$2,128,394	$1,072,892	$1,608,611	$2,145,127	$1,063,149	$1,598,867	$2,135,383	$1,059,918	$1,595,636	$2,132,152	$1,051,932	$1,587,650	$2,124,166
Lifetime Benefits, adjusted for availability	$302,974	$302,974	$302,974	$336,988	$336,988	$336,988	$394,133	$394,133	$394,133	$360,856	$360,856	$360,856	$349,822	$349,822	$349,822	$322,549	$322,549	$322,549
BCR (financial)	0.29	0.19	0.14	0.32	0.21	0.16	0.37	0.25	0.18	0.34	0.23	0.17	0.33	0.22	0.16	0.31	0.20	0.15
NPV (financial)	-$743,226	-$1,278,944	-$1,815,460	-$719,172	-$1,254,890	-$1,791,406	-$678,759	-$1,214,478	-$1,750,994	-$702,292	-$1,238,011	-$1,774,527	-$710,096	-$1,245,814	-$1,782,330	-$729,383	-$1,265,102	-$1,801,618
Value of Avoided Outages ($)	$379,452	$379,452	$379,452	$937	$937	$937	$47,388	$47,388	$47,388	$90,527	$90,527	$90,527	$17,125	$17,125	$17,125	$337,021	$337,021	$337,021
Net Avoided Emissions ($)**	-$34,094	-$34,094	-$34,094	-$20,054	-$20,054	-$20,054	-$25,265	-$25,265	-$25,265	-$33,276	-$33,276	-$33,276	-$21,890	-$21,890	-$21,890	-$32,459	-$32,459	-$32,459
NPV net Value of Avoided Outages and Emissions	-$397,868	-$933,587	-$1,470,102	-$738,289	-$1,274,008	-$1,810,524	-$656,636	-$1,192,355	-$1,728,871	-$645,041	-$1,180,760	-$1,717,276	-$714,861	-$1,250,580	-$1,787,095	-$424,821	-$960,540	-$1,497,056

*Lifetime adjusted costs vary across facilities due to varying levels of energy cost and demand charge savings and their associated tax implications.

** Avoided emissions include CO_2, SO_2 and NO_2. Negative dollar amounts indicate net increases in emissions.

Battery Size

A cost-benefit analysis of batteries sized at 0.25 MW rather than 1 MW was run to assess whether BCRs or NPVs improve when ES is deployed at smaller scales for the same facilities. Table 25 compares the NPVs, BCRs, net avoided emissions, value of avoided outages and NPV incorporating emission changes and avoided outages on a per-megawatt basis for 1 MW batteries and independent 0.25 MW batteries across facilities.

These results are presented on a per-MW basis (i.e., showing four times the results for the 0.25 MW battery case) for purposes of comparison. However, it should be noted that these smaller battery sizes are not necessarily optimal for these use cases. Further analysis would be required to determine the optimal battery size and duration for EBM and resiliency purposes. To the extent that optimal battery sizes might be larger or smaller than 1MW, this would affect the total costs required to install and/or subsidize the storage required for any given use case. We find that BCRs and NPVs do improve on a per-megawatt basis for these use cases, in some cases significantly, with relatively small cost increases offset by more significant benefit increases. Importantly, while NPVs remain significantly negative, we find that significant resiliency benefits can be attained at smaller battery sizes, indicating potential targets for incentivizing storage installation.

Table 25: Per-Megawatt Comparison of 1 MW and .25 MW Batteries- NPV, BCR, Net Emissions and Value of Avoided Outages for Facility Resiliency – Standalone ES.

	Net Present Value		Benefit-Cost Ratio		Net Avoided Emissions		Value of Avoided Outages		NPV w/ Emissions and Avoided Outages	
Battery Size:	1 MW	0.25 MW (x4)	1 MW	0.25 MW (x4)	1 MW	0.25 MW (x4)	1 MW	0.25 MW (x4)	1 MW	0.25 MW (x4)
Hospital	-$1,278,944	-$1,106,880	0.19	0.33	-$34,094	-$14,957	$379,452	$551,305	-$933,587	-$570,532
Apartment Complex	-$1,254,890	-$887,590	0.21	0.49	-$20,054	-$16,571	$937	$3,245	-$1,274,008	-$900,916
Hotel	-$1,214,478	-$750,858	0.25	0.58	-$25,265	-$17,339	$47,388	$140,360	-$1,192,355	-$627,837
Office	-$1,238,011	-$1,036,813	0.23	0.38	-$33,276	-$13,078	$90,527	$141,701	-$1,180,760	-$908,190
Secondary School	-$1,245,814	-$1,025,229	0.22	0.39	-$21,890	-$13,014	$17,125	$39,477	-$1,250,580	-$998,766
Supermarket	-$1,265,102	-$1,048,262	0.2	0.38	-$32,459	-$13,880	$337,021	$557,263	-$960,540	-$504,879

Given the additional benefits that can occur when ES is coupled with PV (see Case #2 below), Table 26 compares the results for the PV-coupled scenarios for the facilities with the smallest and largest differences in BCR between the two battery sizes in the Standalone ES case – hospitals and apartment complexes. Coupling with PV significantly improves the results in terms of the NPV and the BCR. In the case of a hospital, where the VOLL is high, when the value of avoided outages is added to the financial benefits, the NPV of the project is positive under this configuration.

Table 26: Per-Megawatt Comparison of 1 MW and .25 MW Batteries- NPV, BCR, Net Emissions and Value of Avoided Outages for Facility Resiliency – PV+ES.

	Net Present Value		Benefit-Cost Ratio		Value of Avoided Outages		NPV w/ Avoided Outages	
Battery Size:	1 MW	0.25 MW (x4)	1 MW	0.25 MW (x4)	1 MW	0.25 MW (x4)	1 MW	0.25 MW (x4)
Hospital	-$572,334	-$115,086	0.57	0.92	$368,285	$610,494	-$204,048	$495,408
Apartment Complex	-$612,492	-$133,013	0.52	0.91	$3,208	$3,161	-$609,284	-$129,852

Capital Costs

As indicated in Table 24, the range of capital cost estimates is wide, with low and high estimates ranging from 33-34% higher or lower than the midpoint. However, even at low capital cost estimates, the cost savings from standalone ES result in financial BCRs ranging from 0.29 to 0.37 and NPVs ranging from -$678,759 to -$743,226. Accounting for the Value of Avoided Outages still leaves a minimum net value gap of near $400,000 (hospitals).

Discount Rate

For the base case with no PV, using the mid-range cost estimates and moderate de-escalation scenario, we tested discount rates of 7% and 15% (versus the baseline assumption of 10%) to assess their impacts on BCRs and NPV [see Table 27 and Figure 74]. On average, the 7% rate results in an increase of about 10% in the NPV of projects with no PV, and the 15% discount rate results in NPVs approximately 10% lower than the baseline. These equate to BCRs about 0.05 points higher than baseline for the 7% discount rate and about .05 points lower than baseline for the 15% discount rate.

Table 27: Discount Rate Sensitivity Mid-Range Cost and De-Escalation for 2020.

	Benefit-Cost Ratio		
Discount Rate:	**7%**	**10% (Base Case)**	**15%**
Hospital	0.24	0.19	0.14
Apartment Complex	0.26	0.21	0.16
Hotel	0.30	0.25	0.18
Office	0.28	0.23	0.17
Secondary School	0.27	0.22	0.16
Supermarket	0.25	0.20	0.15

	Net Present Value		
Discount Rate:	**7%**	**10% (Base Case)**	**15%**
Hospital	-$1,156,675	-$1,278,944	-$1,419,532
Apartment Complex	-$1,128,245	-$1,254,890	-$1,400,735
Hotel	-$1,080,481	-$1,214,478	-$1,369,154
Office	-$1,108,295	-$1,238,011	-$1,387,544
Secondary School	-$1,117,518	-$1,245,814	-$1,393,642
Supermarket	-$1,140,314	-$1,265,102	-$1,408,714

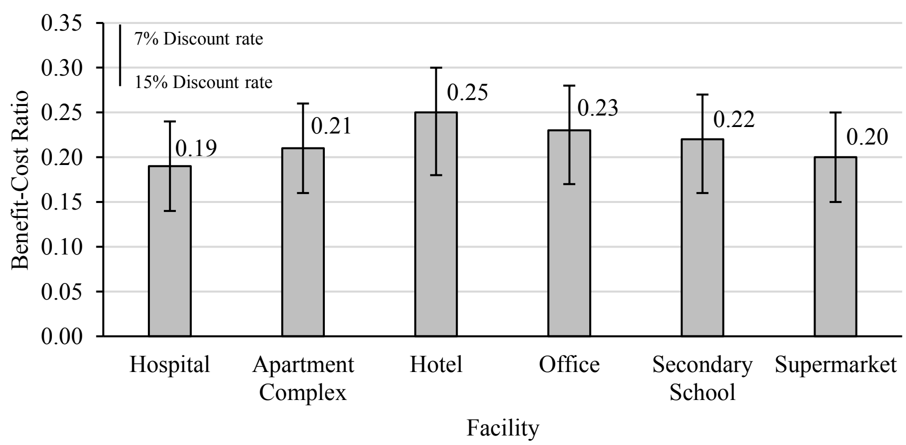

Figure 74: Discount Rate Sensitivity of BCRs for Mid-Range Cost and De-Escalation for 2020.

Cost De-Escalation

We tested the sensitivity of the base case results in 2030 using the low, moderate and high cost de-escalation trajectories applied to the mid-range cost-estimate for 2017/2018.[268]

Moore's law is familiar to most in the technology area. Moore[269] showed that the cost of computing has dropped exponentially as cumulative production has increased, leading to an expectation that such cost decreases (or equivalent performance improvements) can continue. Wright[270] made similar claims about the airline industry, although he assumed a power law relationship. Explanations for these patterns of cost reduction variously focus on learning effects, experience effects, investment effects, the achievement of scale economies, and other factors, and comparative studies across technologies show that regular cost reductions often occur.[271]

Recent work has shown that these models predict best when the historical record of cost reductions shows a good statistical fit with (1) the passage of time, (2) effort measured by patents, and (3) cumulative production.[272] We recognize that there are profound uncertainties embedded within any such modeling effort, but the regularities and strategies are available for managing these uncertainties.[273]

Schmidt et al. apply this approach to ES technologies and find the following: "regardless of technology, capital costs are on a trajectory towards US$340 +/- 60 kWh-1 for installed stationary systems and US$175 +/- 25 kWh-1 for battery packs once 1 TWh of capacity is installed for each technology. Bottom-up assessment of material and production costs indicates this price range is not infeasible. Cumulative investments of US$175–510 billion would be needed for any technology to reach 1 TWh deployment, which could be achieved by 2027–2040 based on market growth projections."[274]

The implication is that cost reductions require time and money, hence energy policymakers desiring to encourage the adoption of energy ES may want to provide incentives. There is a limit to the effectiveness of incentives because the passage of time (i.e., for learning and experience) and the accomplishment of innovations (e.g., patents) are still needed.[275]

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[268] De-escalation from 2017/2018 to 2020 does not result in significant per-kW capital cost differences between the high and moderate or low and moderate de-escalation scenarios. Because the moderate and high de-escalation rates are similar over the short-term (2018-2020), at the lowest bound – i.e., the lowest cost per kW at the highest cost de-escalation rate – CapEx costs are about the same as under the low-cost/moderate de-escalation results shown in Table 24 resulting in similar BCRs and NPVs. With the lowest de-escalation rate, the highest per-kW CapEx estimate is about 8% higher than the high estimates used in Table 24, again resulting in similar BCRs and NPVs.

[269] G.E. Moore. 1965. Cramming more components onto integrated circuits. *Electron. Mag*. 38(8).

[270] T.P. Wright. 1936. Factors affecting the cost of airplanes. (*J. Aeronaut. Sci.* 3 (4), 122–128).

[271] B. Nagy, Farmer, J.D., Bui, Q.M., Trancik, J.E., 2013. Statistical basis for predicting technological progress. (PLoS ONE 8, 1–7).

[272] C.L. Magee, S. Basnet, J.L. Funk and C. L. Benson. 2016. Quantitative empirical trends in technical performance, (*Technological Forecasting and Social Change*,104: 237-246, https://doi.org/10.1016/j.techfore.2015.12.011).

[273] J. Doyne Farmer and Francois Lafond. 2016. How predictable is technological progress? (*Research Policy*, 45(3): 647-665, https://doi.org/10.1016/j.respol.2015.11.001).

[274] O.Schmidt, Hawkes, A. Gambhir and I. Staffell. 2017. "The future cost of electrical energy storage based on experience rates." (*Nature Energy* volume 2. Article number: 17110, Pg. 1. https://doi.org/10.1038/nenergy.2017.110).

[275] C.L. Magee, S. Basnet, J.L. Funk and C. L. Benson. 2016. Quantitative empirical trends in technical performance, (*Technological Forecasting and Social Change*,104: 237-246, https://doi.org/10.1016/j.techfore.2015.12.011).

Additionally, the relationship between cost reductions and time/effort/production is statistical and not deterministic, so lower costs are not guaranteed.

In the near term (i.e., for time horizons up to 2030), straight-line extrapolation of recent cost-reduction trends is a reasonable approach for this analysis. Longer-term analysis should account for the exponential relationships with time, effort, and cumulative production. The JRC and Bloomberg cost trajectories used in this case largely reflect this approach.

Table 28 provides the BCRs and NPVs for the mid-range Li-ion cost estimate for each facility type given the low, moderate and high-cost de-escalation rates if the investments were made in 2030, rather than 2020. In order to compare the 2030 results to the 2020 results, 2030 results are discounted to 2020. Given the expectation of cost de-escalation, while the benefits per unit of installed Li-ion storage are the same in real terms from year to year, the NPV and BCR for investment in Li-ion storage will be more attractive in 2030 than in 2020 or if spread out over the intervening period. This logic could change if there were a decline in projected benefits, increases in costs, or if other storage technologies present potentially lower costs or enhanced benefits relative to Li-ion. Relative to the base case in 2020, CapEx per kW in the moderate de-escalation scenario is about 28% lower in real terms in 2030, resulting in BCRs about eight percentage points higher than the implementation in 2020. Under the more accelerated high-cost de-escalation scenario, actual CapEx costs are about 45% lower in 2030, resulting in BCRs about 0.18 points higher on average. NPVs are significantly lower than in the case of implementation in 2030

Table 28: BCR and NPV by Facility Type for Low, Moderate and High Cost De-escalation Rates Mid-Range CapEx Estimates, 2030 Standalone ES.

2030						
CapEx Cost De-Escalation Rate:	**Low**		**Moderate**		**High**	
2030 CapEx/kW	$1,573		$1,422		$1,069	
Facility	**BCR**	**NPV**	**BCR**	**NPV**	**BCR**	**NPV**
Hospital	0.24	-$371,972	0.26	-$325,499	0.35	-$217,212
Apartment Complex	0.26	-$362,698	0.29	-$316,225	0.38	-$207,938
Hotel	0.30	-$347,117	0.34	-$300,645	0.44	-$192,357
Office	0.28	-$356,190	0.31	-$309,718	0.41	-$201,430
Secondary School	0.27	-$359,199	0.30	-$312,726	0.40	-$204,438
Supermarket	0.25	-$366,635	0.28	-$320,162	0.37	-$211,875

Case #2 – ES with PV

In the second set of scenarios, we repeat the analysis but with the assumption that the ES is co-located with PVs sized to provide up to 80% of each facility's peak load. This assumption applies for both existing and co-installed PV.[276]

Battery specifications include:

- Battery Size: 1 MW
- Battery Duration: 4-hour
- Year: 2020
- ITC: (26% in 2020)
- Depreciation: 5-Year MACRS

Demand charge savings and energy cost savings are calculated to reflect only those incremental savings enabled by the presence of storage in addition to PV.

The extent to which the batteries are charged by PV or from the grid is determined by simulations and optimization models that take into account facility demand, weather condition, and price of electricity to find ES optimal dispatch and state of charge. The percentage of total charge from PV has implications for access to, and the size of the federal ITC, as well as the use of a 5-year, rather than a 7-year accelerated depreciation schedule.[277]

When coupled with PV, we also assume that battery enables the additional load to be served during longer outages. As in the previous case, we assume three short-duration outages per year, as well as a 20% chance of a longer-duration outage. Longer duration outages were not considered in the Standalone ES analysis as grid-charged ES would not have value for longer outages beyond the duration of one battery discharge cycle. Note that the extent to which ES enables avoidance of outages for shorter-duration events is significantly lower in the presence of PV, as PV directly serving load during the outage is estimated to offset the role of ES.

It should also be noted that some critical facilities such as hospitals have, often by legal mandate, significant diesel generation (DG) or other redundant back-up power resources. Such resources may carry high operating costs and also may suffer significant disruption from major outage events due to disruptions in fuel availability. As such, the resiliency benefits (Value of Avoided Outages) for long-duration outages in this simulation assume the absence of other back-up power; however, where such resources are available, the marginal benefit of ES would likely be minimal.

[276] Based on an IRS private letter ruling issued in 2011, which found that ES added to an existing wind power installation was eligible for the ITC, these simulations assume that the same conditions would apply to ES added to an existing PV installation. See https://www.irs.gov/pub/irs-wd/1208035.pdf.

[277] In theory, battery projects charging fully with PV would also have access to bonus depreciation, which allows solar developers to depreciate 100% of their capital costs in the first year of operation. However, correspondence with analysts at the National Renewable Energy Laboratory (NREL) indicates that this provision is rarely used, with developers preferring to spread the tax benefit over the 5-year MACRS depreciation schedule. As such, this provision is not included in the analysis.

A Note on Emissions for Battery Installations with PV: While the addition of battery storage may enable additional emission reduction beyond that which would be achieved via PV alone, it is difficult to determine to which technology those reductions should be attributed – the storage or the renewable resource itself. In longer-term scenarios with threshold levels of renewable energy added to the grid, by maximizing the exploitation of highly variable resources, ES may be responsible for significant levels of emission reduction. However, at smaller scales involving only PV for resiliency purposes at the facility level, we assume that the presence of PV is responsible for any reduction in emissions. To the extent that charging from PV will reduce the marginal emissions increase that result from charging solely from the grid, the net increase in emissions from the battery will be reduced to a negligible level.

Table 29 provides the NPV and BCRs, as well as the net value of avoided emissions and the value of avoided outages for six facility types based on their calculated EBM benefits (i.e., demand charge and energy cost reductions) and the mid-range estimate of capital expenditures. Table 30, Figure 75 and Figure 76 provide a comparison of the BCRs, NPVs and value of avoided outages for the scenario analyses with and without PV. Table 31 provides more detailed data for each facility, with benefits, adjusted costs, benefit-cost ratios and net present values for the range of CapEx estimates for each facility.

Table 29: Lifetime NPV, BCR, and Value of Avoided Outages for Facility Resiliency – ES with PV

	Net Present Value	Benefit-Cost Ratio	Value of Avoided Outages	NPV w/ Avoided Outages
Hospital	-$572,334	0.57	$368,285	-$204,048
Apartment Complex	-$612,492	0.52	$3,208	-$609,284
Hotel	-$446,903	0.66	$63,820	-$383,083
Office	-$976,469	0.43	$77,924	-$898,545
Secondary School	-$1,140,242	0.30	$13,114	-$1,127,128
Supermarket	-$595,362	0.55	$303,826	-$291,536

Clearly the presence of PV significantly enhances the value of the battery storage, by enhancing demand charge and energy cost savings reductions and in several cases allowing for tax benefits that further reduce net capital costs.[278] Further, the two technologies together provide significant resiliency benefits, allowing for significant outage-cost avoidance in the case of long-duration outages. [Note: the Value of Avoided Outages represents that portion attributable to the presence of battery storage in addition to PV.] Hotels, hospitals, supermarkets and apartment complexes have financial NPVs less than half those in the case of standalone ES. Based on the high VOLL per MWh and the significant continued operations enabled by battery storage in the presence of PV, the resiliency value (Value of Avoided Outages) in the case of hospitals and supermarkets increases the net NPV by more than half. This suggests that hospitals and

[278] In cases where facilities do not qualify for the ITC, there is a small increase in total costs relative to the case with no PV, as the higher cost reductions result in higher taxable operating margins.

supermarkets would be among the facilities that could potentially benefit the most from on-site energy storage when coupled with PV.

As a further issue with resilience value, we might expect that for extended outages, ES, when coupled with PV, might enable serviceable, powered, emergency gathering spaces, where the societal value might be substantially higher than the VOLL attributed to the facility based on its normal use would indicate. Installations such as the solar+storage at Hopewell Valley High School, for example, provide a gathering place with abundant value to the nearby community facing an extended outage. Putting a direct dollar value on these emergency resiliency applications (that might only be rarely used) is a difficult proposition and beyond the scope of this study. However, such societal value is likely not captured in standard VOLL estimates and the estimates of the Value of Avoided Outages in some cases are thus likely underestimated.

Table 30: Comparison: ES (Li-Ion Battery) Alone and with PV by Facility Mid-Range Cost and De-Escalation for 2020.

	Benefit-Cost Ratio	
	ES Alone	**ES with PV**
Hospital	0.19	0.57
Apartment Complex	0.21	0.52
Hotel	0.25	0.66
Office	0.23	0.43
Secondary School	0.22	0.30
Supermarket	0.20	0.55
	Net Present Value	
	ES Alone	**ES with PV**
Hospital	-$1,278,944	-$572,334
Apartment Complex	-$1,254,890	-$612,492
Hotel	-$1,214,478	-$446,903
Office	-$1,238,011	-$976,469
Secondary School	-$1,245,814	-$1,140,242
Supermarket	-$1,265,102	-$595,362
	Value of Avoided Outages	
	ES Alone	**ES with PV**
Hospital	$379,452	$368,285
Apartment Complex	$937	$3,208
Hotel	$47,388	$63,820
Office	$90,527	$77,924
Secondary School	$17,125	$13,114
Supermarket	$337,021	$303,826

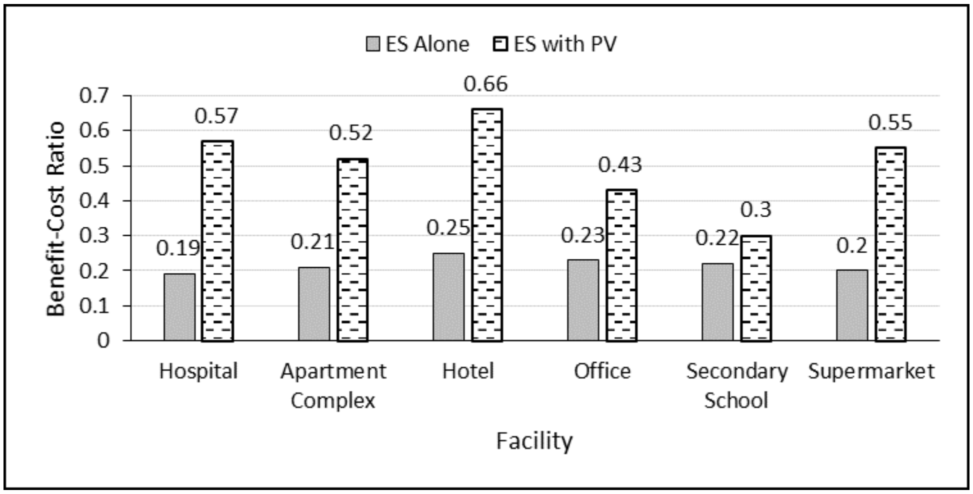

Figure 75: Facility Benefit-Cost Ratios: ES Alone and with PV, 1 MW Battery, Mid-Range Cost for 2020.

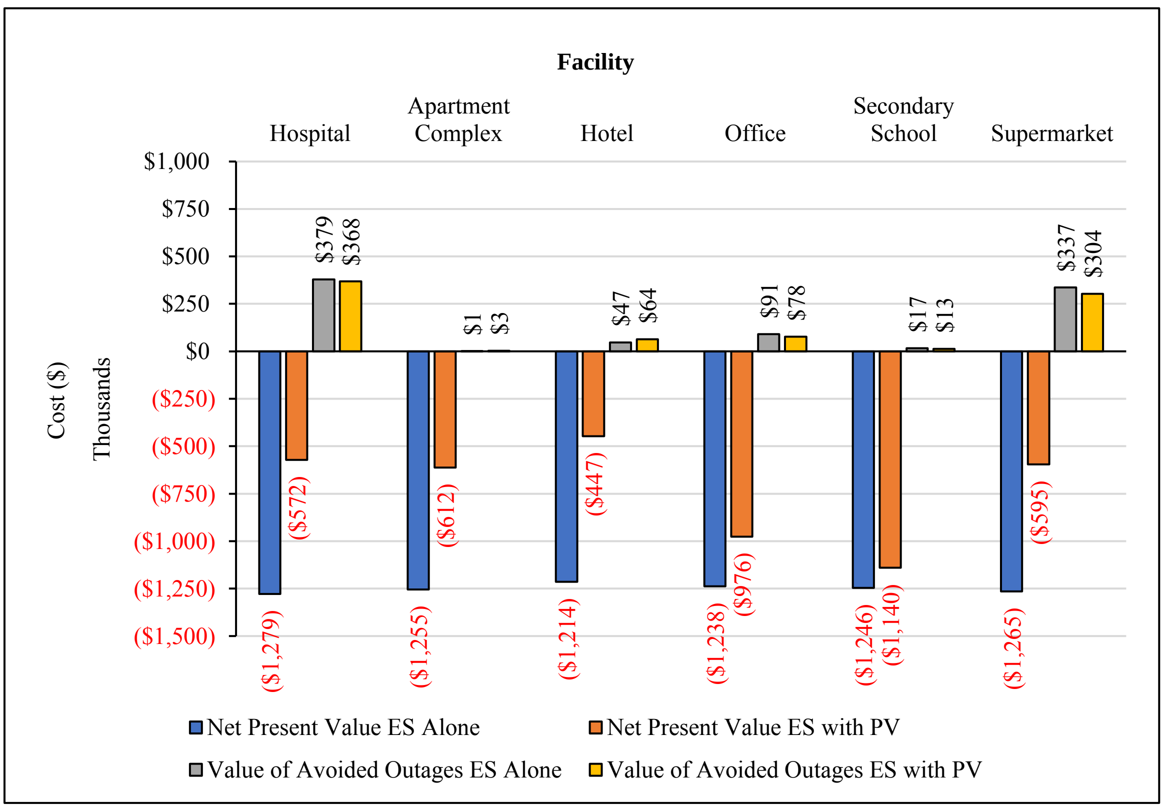

Figure 76: Facility NPV and Value of Avoided Outages, ES Alone and with PV, 1 MW Battery, Mid-Range Cost for 2020

Table 8

Table 31: Comparison: ES (Li-Ion Battery) Alone and with PV by FacilityMid-Range Cost and De-Escalation for 2020

Battery Size:	1 MW	
PV Size:	Serves 80% of Peak Load	
Battery Duration:	4 Hours	
Year:	2020	
ITC:	26%	Applies only where annual share of PV charging is 75% or greater and is pro-rated to % of PV charging.
Depreciation:	Varies	5-year MACRS where ITC applies, 7-year MACRS otherwise.
Cost De-Escalation Scenario:	Moderate	
Discount Rate:	10%	
Annual Operating Costs:	$10/kW/yr.	
Blended Tax Rate:	28.1%	
Availability	96.0%	
Efficiency:	85.0%	

Facility:	Hospital			Apartment Complex			Hotel		
CapEx Level:	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**
PV Size	1.6	1.6	1.6	0.7	0.7	0.7	1.2	1.2	1.2
% PV Charging	79%	79%	79%	85%	85%	85%	89%	89%	89%
Capex/kW	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640
Lifetime Adjusted Costs (CapEx + OpEx)*	$921,862	$1,324,766	$1,728,270	$875,904	$1,269,464	$1,663,610	$924,912	$1,312,243	$1,700,151
Lifetime Benefits, adjusted for availability	$752,433	$752,433	$752,433	$656,972	$656,972	$656,972	$865,341	$865,341	$865,341
BCR (financial)	0.82	0.57	0.44	0.75	0.52	0.39	0.94	0.66	0.51
NPV (financial)	-$169,430	-$572,334	-$975,837	-$218,931	-$612,492	-$1,006,638	-$59,572	-$446,903	-$834,810
Value of Avoided Outages ($)	$368,285	$368,285	$368,285	$3,208	$3,208	$3,208	$63,820	$63,820	$63,820
NPV net Value of Avoided Outages and Emissions	$198,856	-$204,048	-$607,552	-$215,723	-$609,284	-$1,003,430	$4,248	-$383,083	-$770,990

Facility:	Office			Secondary School			Supermarket		
CapEx Level:	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**
PV Size	1.3	1.3	1.3	0.8	0.8	0.8	1.5	1.5	1.5
% PV Charging	62%	62%	62%	64%	64%	64%			
Capex/kW	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640
Lifetime Adjusted Costs (CapEx + OpEx)*	$1,171,441	$1,707,159	$2,243,675	$1,103,630	$1,639,349	$2,175,865	$922,104	$1,328,123	$1,734,746
Lifetime Benefits, adjusted for availability	$730,690	$730,690	$730,690	$499,106	$499,106	$499,106	$732,761	$732,761	$732,761
BCR (financial)	0.62	0.43	0.33	0.45	0.30	0.23	0.79	0.55	0.42
NPV (financial)	-$440,750	-$976,469	-$1,512,985	-$604,524	-$1,140,242	-$1,676,758	-$189,343	-$595,362	-$1,001,985
Value of Avoided Outages ($)	$77,924	$77,924	$77,924	$13,114	$13,114	$13,114	$303,826	$303,826	$303,826
NPV net Value of Avoided Outages and Emissions	-$362,826	-$898,545	-$1,435,061	-$591,409	-$1,127,128	-$1,663,644	$114,483	-$291,536	-$698,159

*Lifetime adjusted costs vary across facilities due to varying levels of energy cost and demand charge savings and their associated tax implications.

ES for frequency regulation and arbitrage

We examined the benefits and costs of Li-ion battery storage for FR in 2020. We ran three scenarios:

- The battery is used only for price arbitrage.
- The battery is used only for frequency regulation.
- A battery capacity of 25% is allocated to frequency regulation and the remainder to arbitrage. This is an arbitrary allocation and for demonstration purposes.

We measured the BCR for the low- mid-range and high CapEx estimates for a 1 MW, 4-hour duration Li-ion battery, for each case. For purposes of comparison, a 4-hour duration battery was used for all scenarios; however, when used for FR alone, a shorter discharge duration would be sufficient and result in lower CapEx costs to achieve the same revenues.

As in the resiliency scenarios, annual O&M costs are set at $10/kw/yr. and a 10% discount rate is used. Revenue streams include energy arbitration, FR and capacity market revenue. Total costs include capital expenditures, operating expenditures and estimated taxes on net operating costs (i.e., frequency regulation and arbitrage revenue less O&M costs). No PV, and hence no ITC, is assumed.

Table 32 provides the range of BCRs and NPV for installation of 600 MW of Li-ion battery capacity for FR and arbitrage applications. Revenues in the arbitrage only scenarios are minimal and dedicated arbitrage applications are thus not viable. BCRs for FR only and mixed FR/AR applications range from .91 in the case with highest CapEx costs to 1.5 in the case of the lowest CapEx costs. In the case of high CapEx costs, both FR applications have BCRs slightly below 1.0, indicating a potential incentive target if true capital costs are at the high end of the estimate range.

Table 32: Benefit-Cost Ratios and Net Present Value for Deployment of 600 MW of Li-ion Battery Energy Storage for Frequency Regulation and Arbitration BCR and NPV.

		Low CapEx	Mid-Range CapEx	High CapEx
FR Only	**BCR**	1.50	1.14	0.92
	NPV	$515,658,892	$194,227,657	-$127,681,898
AR Only	**BCR**	0.68	0.47	0.36
	NPV	-$231,770,143	-$553,201,378	-$875,110,933
25% FR/75% AR	**BCR**	1.49	1.13	0.91
	NPV	$494,716,467	$173,285,232	-$148,624,323

Distribution Network Level Applications

In addition to facility-level and market-participation applications, we tested a variety of scenarios to assess the capacity of ES – specifically Li-ion batteries – to support and enhance the role of PV at the distribution level.

These scenarios mirror the distribution level applications described in Element 1 of this report. Each distribution network is composed of individual nodes (facilities and other sites, as well as a substation), and simulations are used to determine the optimal size of PV to be installed in the network both with and without ES, for cases in which the PV and ES resources are centralized at the substation and in which they are distributed across the nodes of the network. Simulations were also run to assess the effects of installing ES without PV. Benefits in the PV+ES scenarios relative to those with PV alone include reduced energy costs (reduced grid imports), demand charge reductions, FR and price arbitration revenues (if any), the value of pollution reduction (i.e., total consumption reduction) resulting from that portion of total PV-served load that is attributable to the availability of battery storage, and the value of avoided outages attributable to the presence of PV+ES. Costs include both the cost of ES (using the mid-range CapEx estimate of $1,967/kW for a 4-hour battery), and the capital cost of the additional installed PV enabled by the ES (set at $2,000/kW). Three distribution networks with three different rate structures are each modeled twice, once with PV and ES centralized at the substation level, and once with PV and ES distributed at the node level below the substation.

Scenario #1: Nine-Node Network

In the first scenario, we modeled a nine-node network, adding PV with and without ES. The network does not participate in the wholesale market for FR or arbitrage. The centralized network is optimized with 2,019 kW of PV in the absence of ES. The PV capacity is increased to 2,523 kW with the addition of 359 kW of Li-ion battery storage of 4-hour duration. The distributed network is optimized with 1,970 kW of PV in the absence of ES. The PV capacity is increased to 2,510 kW with the addition of 89 kW of Li-ion battery storage of 4-hour duration.

Table 33 provides the incremental addition of PV and the incremental reductions in peak demand and grid-energy consumption for the PV+ES case relative to PV alone for the centralized and decentralized network cases, as well as the effects of adding standalone ES at the substation.

Table 33: Nine-Node Network. Additional Peak Demand Reduction and Energy Savings from ES and Supported PV

	Total PV Installed with ES (kW)	Additional PV Supported by ES (kW)	Total ES Installed (kW)	Additional Energy Savings Supported by ES (MWh)	Additional Peak Demand Reduction Supported by ES (kW)
Centralized with PV	2,523	504	359	633	303
Decentralized with PV	2,510	540	89	704	282
Centralized ES Only	-	-	359	-210	138

Table 34 provides the financial benefit-cost ratios and the value of avoided emissions and avoided outages for each of the nine-node network simulations (centralized, decentralized, centralized with ES only). In this case, the VOLL is network-wide, rather than specific to a particular type of facility. We use a lost load value of $10,000/kWh across the networks. As in the facility resiliency cases, we assume three short-duration outages each year and a 20% probability of a long-duration outage each year. The results assume that the ES components of the projects do not qualify for the ITC.

Table 34: Lifetime NPV, BCR, Net Emissions and Value of Avoided Outages Attributable to ES for nine-node Network.

Configuration	Net Present Value	Benefit-Cost Ratio		Net Avoided Emissions*	Value of Avoided Outages
Centralized with PV	-$903,782	0.41		$158,785	$374,329
Decentralized with PV	-$559,665	0.53		$176,595	$383,174
Centralized ES Only	-$424,734	0.27		-$9,149	$44,153

* Avoided emissions include CO_2, SO_2 and NO_2. Note that, in cases with PV, these emission reductions are based on the reduced grid-transmitted energy consumed as a result of the PV-generated consumption enabled by the presence of ES and do not reflect the potential near-term increases in emissions that can occur if the battery charges primarily from the grid and charges at off-peak times when marginal unit emissions are higher, while discharging at 85% efficiency during lower-marginal-emission peak hours. These potential increases are included in the Standalone ES case. Negative dollar amounts indicate net increases in emissions.

Note that the value of avoided emissions and the value of avoided outages are significant in the cases with PV and that, in the case of the Decentralized configuration, these benefits are about equal to the financial NPV for the project, indicating a possible target for incentivizing investment.

Assuming that the batteries charged 75% from PV, enabling use of the ITC, would bring the NPV Decentralized case with PV to -$526,688 and the financial benefit-cost ratio to 0.55.

Scenario #2: Twelve-Node Network

In the second scenario, we model a twelve-node network, adding PV with and without ES. The network does not participate in the wholesale market for frequency regulation or arbitrage. The centralized network is optimized with 284 kW of PV in the absence of ES. The PV capacity is increased to 459 kW with the addition of 130 kW of Li-ion battery storage of 4-hour duration. The decentralized network is optimized with 257 kW of PV in the absence of ES. The PV capacity is increased to 486 kW with the addition of 39 kW of Li-ion battery storage of 4-hour duration. Table 35 provides the incremental addition of PV and the incremental reductions in peak demand and grid-energy consumption for the PV+ES case relative to PV alone for the centralized and decentralized network cases, as well as the effects of adding standalone ES at the substation.

Table 35: Twelve-Node Network: Additional Peak Demand Reduction and Energy Savings from ES and Supported PV

	Total PV Installed with ES (kW)	Additional PV Supported by ES (kW)	Total ES Installed (kW)	Additional Energy Savings Supported by ES (MWh)	Additional Peak Demand Reduction Supported by ES (kW)
Centralized with PV	459	175	130	248	120
Decentralized with PV	486	229	39	312	141
Centralized ES Only	-	-	130	-49	105

Table 36 provides the financial benefit-cost ratios and the value of avoided emissions and avoided outages for each of the twelve-node network simulations (centralized, decentralized, centralized with ES only). The NPVs are higher (less negative) than in the case of Network #1 and the BCRs are somewhat higher. Similar to the first network, the negative NPV for the Decentralized network with PV significantly is wholly offset by the additional value of avoided emissions and outages, again indicating that this configuration may generate sufficient financial and societal benefits to justify an incentive.

Table 36: Lifetime NPV, BCR, Net Emissions and Value of Avoided Outages Attributable to 1.84 MW of ES for 12-Node Network.

Configuration	Net Present Value	Benefit-Cost Ratio	Net Avoided Emissions*	Value of Avoided Outages
Centralized with PV	-$302,495	0.45	$62,210	$125,857
Decentralized with PV	-$220,337	0.57	$78,264	$154,383
Centralized ES Only	-$99,577	0.57	-$2,135	$15,924

Assuming that the batteries charged 75% from PV, enabling use of the ITC, would bring the NPV Decentralized case with PV to -$205,794 and the financial benefit-cost ratio to 0.59.

Scenario #3: Seventeen-Node Network

In the third scenario, we model a seventeen-node network, adding PV with and without ES. The network does not participate in the wholesale market for frequency regulation or arbitrage. The centralized network is optimized with 2,364 kW of PV in the absence of ES. The PV capacity is increased to 3,340 kW with the addition of 618 kW of Li-ion battery storage of 4-hour duration. The decentralized network is optimized with 1,690 kW of PV in the absence of ES. The PV capacity is increased to 3,061 kW with the addition of 198 kW of Li-ion battery storage of 4-hour duration. Table 37 provides the incremental addition of PV and the incremental reductions in peak demand and grid-energy consumption for the PV+ES case relative to PV alone for the centralized and decentralized network cases, as well as the effects of adding standalone ES at the substation.

Table 37: Seventeen-Node Network: Additional Peak Demand Reduction and Energy Savings from ES and Supported PV.

	Total PV Installed with ES (kW)	Additional PV Supported by ES (kW)	Total ES Installed (kW)	Additional Energy Savings Supported by ES (MWh)	Additional Peak Demand Reduction Supported by ES (kW)
Centralized with PV	3,340	976	618	251	643
Decentralized with PV	3,061	1,371	198	308	815
Centralized ES Only	-	-	618	-376	403

Table 38 provides the financial BCRs and the value of avoided emissions and avoided outages for each of the seventeen-node network simulations (centralized, decentralized, centralized with ES only). While the BCRs are higher than in the cases of Networks #1 and #2, the scale of the costs and benefits is larger, resulting in lower (more negative) NPVs. The Decentralized network once again has the highest BCR, though the offsetting value of avoided emissions and outages is not as significant as in the prior cases, making it perhaps a less attractive incentive target, given the scale of subsidy that would be required.

Table 38: Lifetime NPV, BCR, Net Emissions and Value of Avoided Outages Attributable to 1.84 MW of ES for ACE 17-Node Network.

Configuration	Net Present Value	Benefit-Cost Ratio	Net Avoided Emissions*	Value of Avoided Outages
Centralized with PV	-$1,301,522	0.57	$62,987	$265,133
Decentralized with PV	-$1,030,728	0.67	$77,260	$327,404
Centralized ES Only	-$593,293	0.44	-$16,381	$4,860

Assuming that the batteries charged 75% from PV, enabling use of the ITC, would bring the NPV Decentralized case with PV to -$957,549 and the financial benefit-cost ratio to 0.69.

Element 5

Determine the optimal amount of energy storage to be added in NJ over the next five years in order to provide the maximum benefit to ratepayers.

Discussion

Performing this task requires a clear definition of the word "optimal," within constraints set by New Jersey's boundaries, the five-year time frame, and the goal of maximizing ratepayer benefit.

Conditions for Maximum Benefit

For ratepayers to receive the maximum benefit of ES (or any other technology) an ES project should have a benefit-cost ratio that exceeds one. If the benefits do not exceed the costs, then ratepayers do not receive the maximum benefit on their investment.

In addition, the monetized benefits (i.e., revenues streams that owners of ES earn) that the owner of the ES facility receives should be less than the cost of the project. In other words, private market actors might not invest in ES without a government incentive. To maximize benefits to ratepayers, they should not pay for investments that the market would undertake on its own without a government incentive.

Based upon the CBA conducted by the New Jersey ESA project, it is not clear whether large investments in ES can provide the maximum benefit to ratepayers. The State, however, may want to consider establishing small pilot programs for various types of ES applications. Such pilot programs would allow the state to obtain better information regarding the costs, benefits, and performance of different ES technologies. Having this additional and more accurate information would enable the State to update its ES plans and to expand ES at the appropriate time.

Pursuing Longer-Term Benefits for Ratepayers

If the State wants to proceed with implementing 600 new megawatts of ES by the year 2021, we outline several options for the State's consideration. These options represent alternative policy objectives that the State may find important. Is the primary objective to encourage learning about ES so that the industry slides more rapidly down the cost curve and each subsequent unit installed becomes cheaper? Is it to encourage the development and deployment of new ES technologies? Is it to improve the reliability and/or resiliency of the current electric power network? Is it some mix of those items? The legislation offers the state some flexibility in prioritizing among these objectives as it progresses to detailed policy design. The following short descriptions indicate how these scenarios differ.

Low-cost today:

This scenario would likely focus on mature technologies, especially Li-ion batteries deployed for FR and thermal storage deployed for peak demand management. Strengths of this strategy are its low cost to the State and its high likelihood of successful implementation. Weaknesses include the significant potential for subsidizing projects that the market would have already undertaken (i.e., free-ridership), and the low likelihood of significant learning from the policy experiment.

Low-cost in the future:

This scenario would focus on technologies that are close to technological maturity but that are likely to enjoy significant economies of scale in manufacturing. Li-ion batteries again come to the fore. Strengths include using state funds to help ES move from niche status to mainstream usage and learning much about the in-place value and operational lessons that widespread deployment provides. Weaknesses include higher program costs for the state and the low likelihood of sparking a dramatic change in ES technologies.

New Technology:

Here, the State would prioritize investments in relatively novel ES (e.g., V2G) technologies rather than those that are more mature. Strengths include encouragement of step changes (i.e., rather than incremental improvements) in ES performance and potential for New Jersey-developed innovations to receive support that may lead to manufacturing job growth. Weaknesses are the risk that technologies may fail or prove to be very costly.

Resilience:

Following the experience of Hurricane Sandy in 2012, homeowners and businesses have placed increased value on back-up sources of electricity. Photovoltaics plus customer-side ES offers a plausible strategy for improving resilience as experienced by the participating customer. Here the State would prioritize incentives to installations that combine ES with PV arrays, where this allows participants to make use of federal tax incentives. Strengths of this strategy are that it delivers a high-value benefit to participants and reduces local vulnerability to storm events. Weaknesses are that fossil-fueled back-up generators are currently much more cost-effective in this application; hence substantial incentives would be needed to attract participants, and unless the program design explicitly directed it, low-income electricity users would be unlikely to benefit.

Renewable hosting:

Here, the State would prioritize its goal of promoting and expanding clean energy by incentivizing ES as a means to enable additional investments in renewable energy. ES can help to increase renewable hosting capacity at the distribution level.

A Mix of the above:

The state could allocate a portion of the total target (e.g., 120 MW each) to projects implementing each of the five priority areas identified above: Low-cost now, Low-cost in the future, New Technology, Resilience and Renewable Hosting. Strengths are the opportunity to learn from systematic policy experimentation, and ease of steering the program in new directions if conditions so warrant. Weaknesses include the reduced scale of each experiment so that impacts may be less visible.

Cost Trajectories and Investment Roadmap

The timing of ES investment is also sensitive to federal tax credits for renewable energy. Figure 77 shows the trajectory of required incentives for the six resiliency cases from 2020 to 2030. Cost reductions from the ITC in 2020 and 2021 result in lower required subsidies for those facilities that in these simulations charge their batteries more than 75% from PV (offices and schools do not charge sufficiently from PV to qualify for the ITC; as a result, their incentive trajectory simply follows the projected cost declines for Li-ion). In 2022, the ITC drops from 22% to 10%, erasing much of the cost advantage of investing in the short term. However, battery cost declines eventually overtake those lost federal tax credits, with required incentives returning to their pre-2022 levels by 2025.

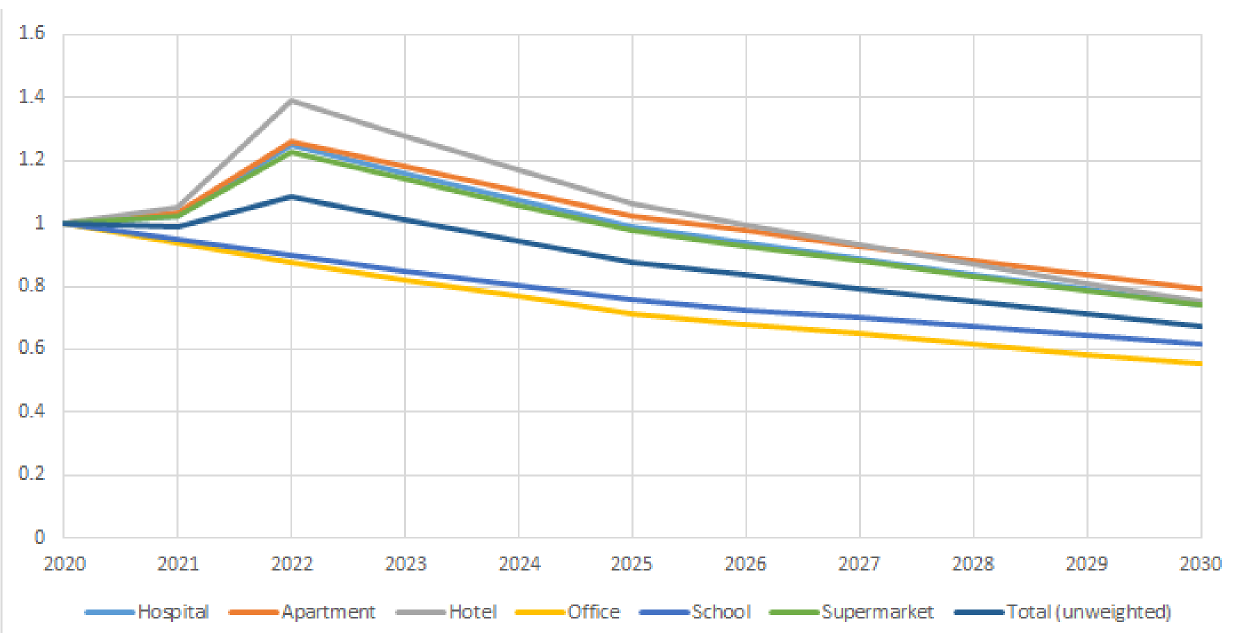

Figure 77: Index of Incentive Size for PV-Coupled ES at the Facility Level.

Element 6

Determine the optimum points of entry into the electric distribution system for distributed energy resources.

Summary of Findings

Quoting the comments made by one of the stakeholders: "*A key to unlocking the potential of energy storage is to locate systems where the maximized revenue streams of the investment (e.g., distribution capital investment deferral; aggregation or wholesale opportunities; and peak shaving/reduction for both customers and EDCs) may be realized*." 279

Analysis and Discussion

Customer Sites

The point of entry for ES depends on the ownership of the system. In case of customer sites, it makes sense to locate ES in facilities with sizeable critical loads that are also subject to higher variability in their daily load profiles to meet their resiliency needs. However, compared to traditional generators (e.g., diesel or natural gas), resiliency alone cannot be the single contributing factor to the point of entry.

We must also consider other contributing factors. For example, as we have already illustrated using examples (see CEA Element 1) and as reiterated by a number of stakeholders' comments, stacking up resiliency with other applications that require dispatchable assets increases the value of ES. Therefore, critical customer sites, which are subject to high risks of demand charges and can generate substantial energy cost savings through paired storage and renewables deployment, are potential candidates for point of entry. With more adoption of mass EVs in the near horizon, critical business facilities with occupants who are prime candidates for EV adoption can also benefit significantly from reduced demand charges due to EV charging utilizing ES.

There may also be other opportunities on the horizon for privately owned ES. Quoting the comments from one of the stakeholders: "*The Federal Energy Regulatory Commission's (FERC) recent Order 841 may create new opportunities for retail storage to participate in wholesale markets. Despite the challenges with these markets, the state may want to encourage the participation of residential storage systems to demonstrate the potential for DER markets. It might be necessary for utilities to play an intermediary role between retail participants and wholesale markets.*" [280]

[279] Rockland Electric Utility Company (RECO). 2019. (Comment made by stakeholder RECO for CEA Element 6 at Energy Storage Stakeholder Meeting held on March 20, 2019. See Appendix B – Stakeholders' Responses)
[280] New Jersey Resources (NJR). 2019. (Comment made by stakeholder NJR for CEA Element 6 at Energy Storage Stakeholder Meeting held on March 20, 2019. See Appendix B – Stakeholder Responses)

ES impact at Transmission level

In the absence of granular interconnectivity, power generation and load data, the ESA ran a few use-case studies to illustrate the ES benefits at bulk level. A unit commitment optimization model was constructed based on a mixed integer linear programming approach to find electrical power generation schedules, ES optimal dispatch and ES optimal allocation within New Jersey transmission network. This model takes into account ramping situations, thermal generation constraints, operating reserve, fuel cost functions, reactive power and transmission system constraints, available renewable power generation and the network dynamics to optimize the status of the power generation facilities. The level of granularity for this problem was considered to be at county level (21 counties in New Jersey) in addition to an average mix of power generation for the adjacent power networks (PA, NY, and NYC). The inputs for the power generators' nameplate and available capacities, transmission network interconnectivity, high level load estimates, etc. are all based on publicly available data on EIA and PJM websites for 2018. Due to the lack of sufficient data, it is assumed that all transmission lines are 230 kV with an average capacity of 400 MW. The objective is to minimize power supply cost and load loss while all the transmission network and thermal generation constraints are fulfilled.

Integration of ES and Offshore Wind

Here, the objective was to evaluate the impact of 600 MW of ES (4-hour discharge duration) integrated with 1100 MW of offshore wind (OSW) generation (with Atlantic county as the point of entry of OSW) and as a part of NJ transmission system. It is assumed that ES+OSW is coupled to the grid through a high voltage transmission line with a 500 MW capacity. The use cases were simulated for heating and cooling seasons for 3 representative days. The results for the three representative cooling season days indicate that ES can recover 4369.81 MWh of OSW to supply the demand during peak hours (Figure 78). For heating season, 4494.96 MWh is recovered to supply the demand when offshore wind power generation is not available and during peak time (Figure 79).

These results are highly sensitive to physical constraints of the network. Our result indicate that ES role is more noticeable when transmission lines have limited capacity. When the transmission lines delivering OSW power to the grid have sufficient capacity, ES impact will become less. This is indicative of the fact that ES can be deployed for transmission line upgrade avoidance while at the same time, it can stabilize OSW power generation by an optimal dispatch during the times wind power generation is not available. OSW can recover and displace OSW power from off-peak hours to on-peak hours to reduce emissions and also avoid the operation of peaker plants.

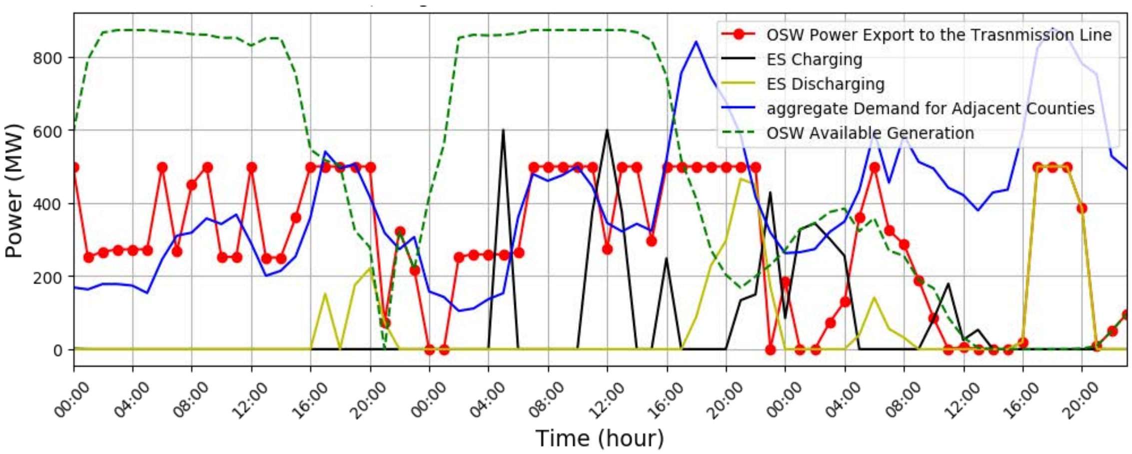

Figure 79: 600 MW of ES supporting OSW during three representative days in heating season.

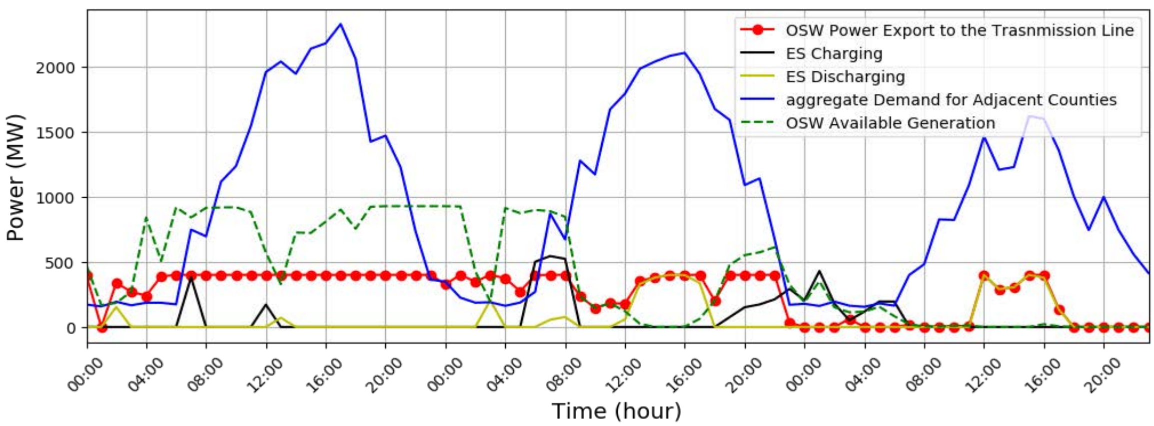

Figure 78: 600 MW of ES supporting OSW during three representative days in cooling season.

Allocation of 600 MW of ES

The same model was reconstructed with additional decision variables to find optimal allocation for 600 MW ES (with 4-hour discharge duration) at the county level for two different design days (cooling season and heating season). Two cases were considered: i) there is no offshore wind, ii) 1100 MW of offshore wind added to the shorelines of Atlantic county. The four scenarios are:

Scenario 1: Summer Design Day in July no OSW.
Scenario 2: Winter Design Day in January no OSW.
Scenario 3: Summer Design Day in July with OSW.
Scenario 4: Winter Design Day in January with OSW.

Table 39 presents optimal allocation for 600 MW of ES at county level. Figure 80 to Figure 83 illustrate the total impact of 600 MW ES charging and discharging on aggregate behavior of NJ electric power demand. As seen in these figures, each allocated ES system charges during off-peak hours and optimally discharges (not necessarily fully) to mitigate the peak demand. This, in turn, indicates that peaker plants can be replaced by ES during on-peak hours to displace cheaper energy generated during off-peak hours to on-peak hours. In addition, ES can be deployed to defer construction of new peaker plants or result in retiring existing peaker plant facilities. The results indicate that optimal ES sizing for transmission network integration is highly dependent on aggregate load profiles and network congestion. For the specific cooling design days in this use case, a considerable portion of ES is allocated to the counties hosting NY transmission lines importing power to the state to mitigate internal NJ congestion during peak hours. For the specific heating design days in this use case, ES is allocated more distributed compared to the cooling season. For cooling season with OSW, ES is preferred to still mitigate the congestion in north New Jersey and Monmouth county while for heating design day, about 109 MW of ES is allocated to OSW to support wind power generation. This also indicates that ES optimal sizing is highly dependent on wind power generation and aggregate load profiles.

Table 39: ES allocation to NJ counties at transmission level.

	Selected Counties	ES Size (MW)
Scenario 1	Monmouth	327.61
	Warren	64.41
	Sussex	207.97
Scenario 2	Middlesex	83.19
	Morris	149.41
	Warren	24.66
	Sussex	43.48
	Passaic	34.1
	Hudson	265.13
Scenario 3	Monmouth	327.61
	Warren	55.6
	Sussex	216.79
Scenario 4	OSW	109.86
	Middlesex	230.98
	Monmouth	33.36
	Morris	75.18
	Sussex	41.25
	Passaic	1.99
	Hudson	107.34

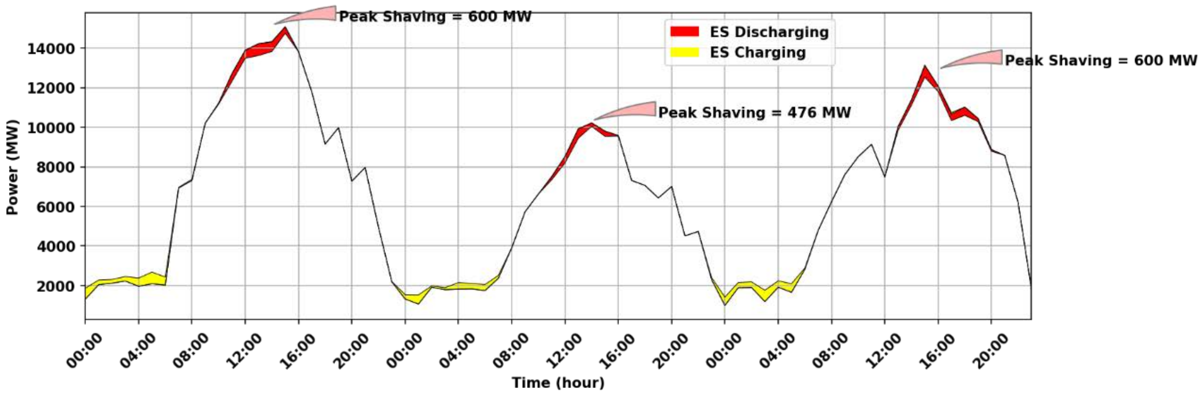

Figure 80: (Scenario 1) Summer design day in July without OSW.

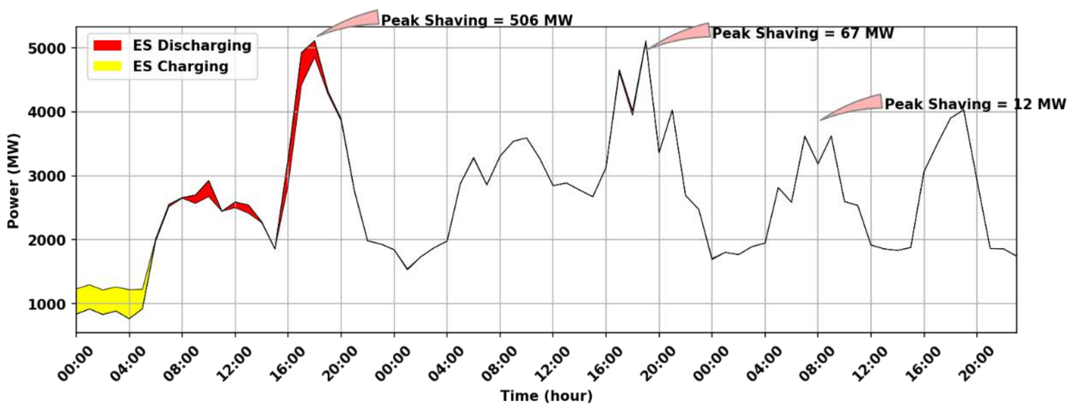

Figure 81: (Scenario 2) Winter design day in January without OSW.

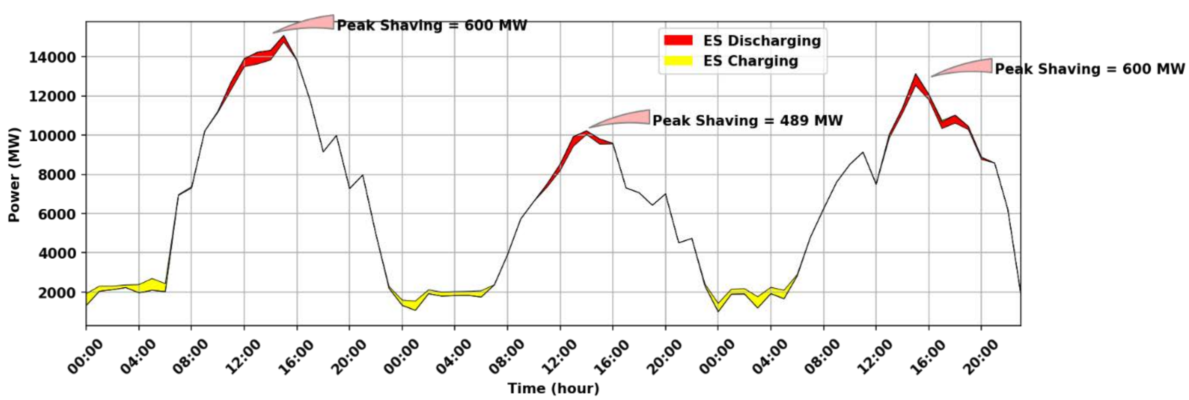

Figure 82: (Scenario 3) Summer design day in July with OSW.

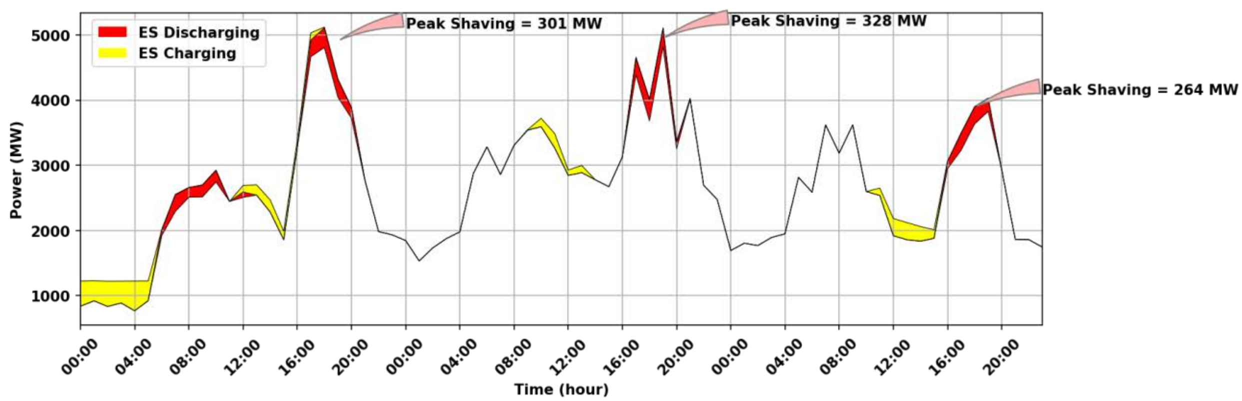

Figure 83: (Scenario 4) Winter design day in January with OSW.

LMP analysis

Total LMP annual daily variation from 2013 to 2018 indicates that the Northeast of NJ has been steadily showing the highest congestion variability since 2013, which makes ES more applicable for arbitrage revenues or mitigating the conditions that create this high congestion. South Jersey shows the highest marginal loss price variations. It is recommended that ES can be deployed for the mitigating congestion and transmission loss based on the historical LMP data.

The spread in peak and off-peak location marginal pricing (LMP) can also be a factor to consider for point of entry at the network level. We conducted a preliminary analysis of PJM LMP across the state in 2017 to identify these locations across the transmission network. These nodes are potential candidates for initial ES allocation, and an incremental ES build up can relieve congestion across the network. With more intermittent renewables, especially with the anticipated 3500 MW of OSW, more variability across the grid is expected.

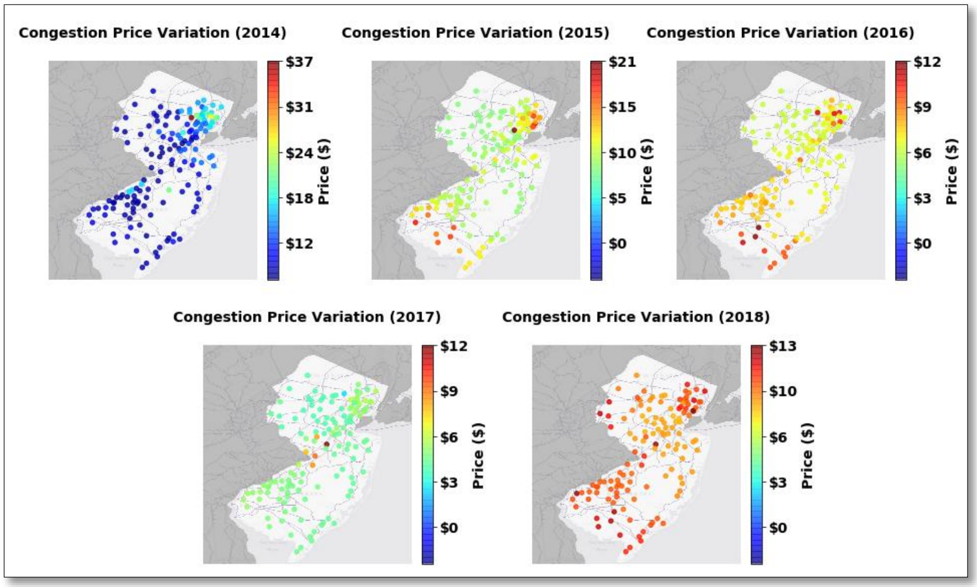

Figure 84: NJ average daily congestion price variation from 2014 to 2018.

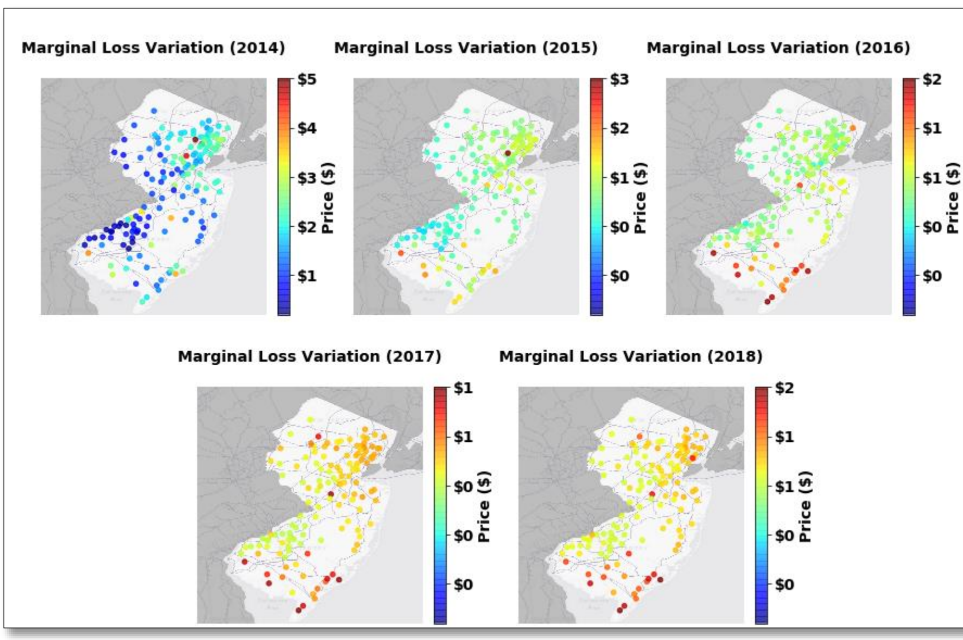

Figure 85: NJ average daily marginal loss price variation from 2014 to 2018.

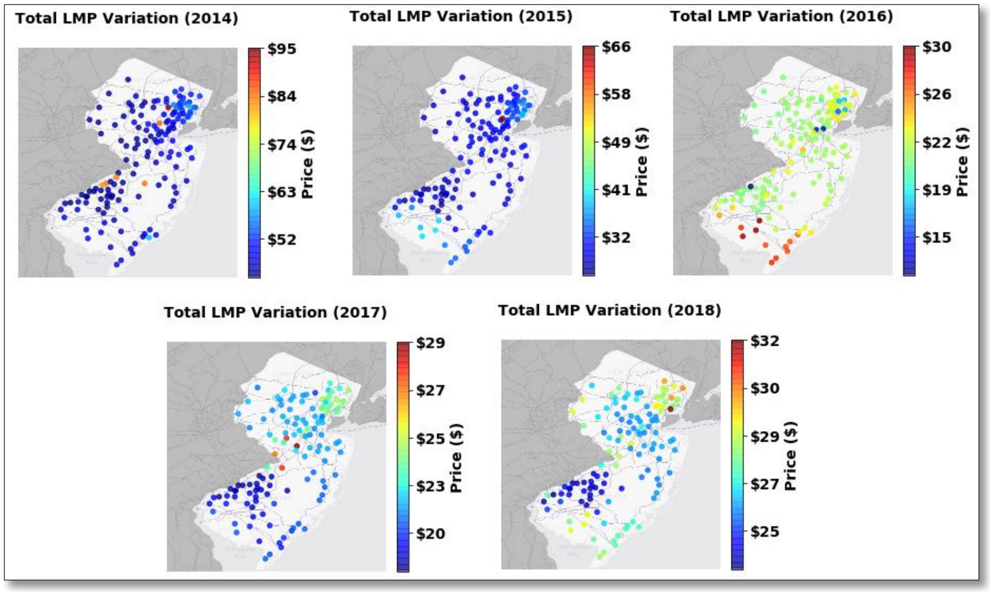

Figure 86: NJ average daily LMP variation from 2014 to 2018.

Element 7

Calculate the cost to the State's ratepayers of adding the optimal amount of energy storage.

Summary of Findings

- We allocated 600 MW of capacity across resiliency applications using three different approaches.
- We find that the most cost-effective allocation results from weighting the distribution across use cases by benefit-cost ratios that account for resiliency value.

Analysis and Discussion

Distribution of 600 MW

We tested several approaches to the distribution of the 600 MW of Li-ion battery storage across the resiliency and market applications described in Element 4. These approaches are based on the low, medium, and high capital cost estimates using the moderate cost de-escalation trajectory and tax parameters for 2020. These approaches do not guarantee optimal allocation of the 600 MW capacity based on scenario analysis.

Approach #1: Unweighted Allocation of Resiliency Applications

In the first approach, we allocate 600 MW across resiliency cases equally – 100 MW per facility type. Table 40 provides the total NPV (financial only – the estimated subsidy required to make the project viable) and the Value of Avoided Outages for the standalone ES and PV-coupled scenarios assuming this equal distribution for the low, mid-range, and high capital cost estimates. At the low CapEx estimate with PV, the financing gap of $168.3 million is relatively low, at about $280,000 per MW, and the value of avoided outages amounts to approximately a 50% offset to this value. At higher financing gaps, the offset by avoided outage value is not significant. The standalone ES applications have significantly larger financing gaps, with a mid-range estimate of $750 million, or about $1.25 million per MW. These higher costs are not significantly offset by outage avoidance.

Table 40: Equal Distribution of 600 MW Across 6 Facility Types Total NPV and Value of Avoided Outages.

		Low CapEx	Mid-Range CapEx	High CapEx
Standalone ES	**NPV**	-$428,292,721	-$749,723,955	-$1,071,633,511
	Value of Avoided Outages	$87,244,932	$87,244,932	$87,244,932
ES with PV	**NPV**	-$168,254,942	-$434,380,106	-$700,901,290
	Value of Avoided Outages	$83,017,733	$83,017,733	$83,017,733

Because these NPV totals are linear with respect to the allocation of the 600 MW total, the allocation of 200 MW would result in totals one-third of the size of those reported in Table 40 These totals are provided in
Table 41. The same adjustment would apply to all allocation results presented in this section.

Table 41: Equal Distribution of 200 MW Across 6 Facility Types Total NPV and Value of Avoided Outages.

		Low CapEx	Mid-Range CapEx	High CapEx
Standalone ES	**NPV**	-$142,764,240	-$249,907,985	-$357,211,170
	Value of Avoided Outages	$29,081,644	$29,081,644	$29,081,644
ES with PV	**NPV**	-$56,084,981	-$144,793,369	-$233,633,763
	Value of Avoided Outages	$27,672,578	$27,672,578	$27,672,578

Approach #2: BCR-Weighted Allocation of Resiliency Applications

In the second approach, we allocate 600 MW across resiliency cases proportionate to the magnitude of their financial benefit-cost ratios – i.e., projects with higher BCRs are allocated larger shares. Table 42 provides the resulting allocation of the 600 MW by facility type for the standalone ES and ES with PV cases. Offices and schools do not typically charge sufficiently from PV (due to their load profiles) to qualify for the ITC; as a result, in the PV-coupled scenarios, their allocations are lower than those facilities that benefit from the ITC.

Table 42: BCR-Weighted Distribution of 600 MW by Facility Type.

	MW	
Facility	**Standalone ES**	**ES with PV**
Hospital	88.7	112.4
Apartment Complex	98.0	102.6
Hotel	113.3	130.3
Office	104.4	84.9
Secondary School	101.5	60.6
Supermarket	94.1	109.2
Total	**600.0**	**600.0**

Table 43 provides the total NPV (financial only – the estimated subsidy required to make the project viable) and the Value of Avoided Outages for the standalone ES and PV-coupled scenarios assuming this proportionate distribution for the low, mid-range, and high capital cost estimates. Because BCRs vary little in the case of standalone ES, the results are similar to the equal distribution; the Value of Avoided Outages is somewhat lower. In the cases with PV, financing gaps range from 6% to 15% lower than in the equal distribution approach, and the Value of Avoided Outages is about 9% higher. As in the first approach, at the low CapEx estimate with PV, the low financing gap (about $240,000 per MW) is significantly offset by the Value of Avoided Outages.

Table 43: BCR-Weighted Distribution of 600 MW by Facility Type.

		Low CapEx	Mid-Range CapEx	High CapEx
Standalone ES	**NPV**	-$427,361,758	-$748,759,509	-$1,070,652,388
	Value of Avoided Outages	$82,160,918	$81,988,064	$81,902,227
ES with PV	**NPV**	-$145,043,672	-$402,160,172	-$659,867,943
	Value of Avoided Outages	$90,385,894	$90,698,646	$90,856,113

Approach #3: BCR+Avoided-Outage-Value-Weighted Allocation of Resiliency Applications

In the third approach, we allocate 600 MW across resiliency cases proportionate to the magnitude of their financial benefit-cost ratios when avoided outages are taken into consideration – that is, giving additional priority to applications with higher avoided outage potential. Table 44 provides the resulting allocation of the 600 MW by facility type for the standalone ES and ES with PV cases.

Table 44: BCR+Avoided-Outage-Value-Weighted Distribution of 600 MW by Facility Type.

	MW	
Facility	**Standalone ES**	**ES with PV**
Hospital	140.3	139.3
Apartment Complex	69.0	85.8
Hotel	89.1	116.4
Office	91.7	78.2
Secondary School	74.7	51.7
Supermarket	135.1	128.6
Total	**600.0**	**600.0**

Table 45 provides the total NPV (financial only – the estimated subsidy required to make the project viable) and the Value of Avoided Outages for the standalone ES and PV-coupled scenarios assuming this BCR+Avoided-Outage-Value-weighted distribution for the low, mid-range, and high capital cost estimates. In the case of standalone ES, the results for financial NPV are similar to the distribution without consideration of avoided outages; however, the Value of Avoided Outages is markedly higher. In the cases with PV, financing gaps are at their smallest and the aggregate Value of Avoided Outages is over 15% higher than in the approach weighted only by BCR, due to the higher allocation of MW to supermarkets and hospitals, which have the highest VOLL.

Table 45: BCR+Avoided-Outage-Value-Weighted Distribution of 600 MW Across 6 Facility Types Total NPV and Value of Avoided Outages.

		Low CapEx	Mid-Range CapEx	High CapEx
Standalone ES	**NPV**	-$430,457,532	-$751,853,160	-$1,073,744,978
	Value of Avoided Outages	$112,813,027	$112,598,924	$112,492,485
ES with PV	**NPV**	-$140,330,970	-$395,957,985	-$652,147,660
	Value of Avoided Outages	$104,598,197	$104,906,990	$105,061,798

Element 8

Determine the need for the integration of DER into the electric distribution system.

Discussion

Electric Distribution Companies (EDCs)

There are already several clean energy filings by some electric distribution companies (EDCs) in New Jersey that incorporate distributed energy resources (DERs). Many of the stakeholders also promoted the incorporation of DERs into the distribution network in their responses to this CEA Element. Overall, these responses support the benefits that DER can bring into the electric distribution system for clean, resilient, cost-effective energy, and for providing flexible resources for variable renewable energy (VRE). One of the stakeholders wrote: "*DERs can be used to "fine-tune" generation, capacity, power quality, and other essential grid products at the distribution level, and in doing so defer the cost of traditional distribution grid upgrades and/or additional transmission service to support load pockets.*"[281] In many of these responses, ES is an essential and integral part of DER.

Town Center Microgrids

In a separate study that our team recently completed for NJ BPU, we examined the anticipated benefits (i.e., in terms of energy cost savings) from a number of Town Center Distributed Energy Resources (TCDER) microgrids proposed across three of New Jersey's EDCs. Some of these microgrids include ES. Further analysis of the results from that study quantifies a clear contribution of ES as part of DER deployment. Furthermore, our findings for CEA Element 1 also pair ES with PV and distributed generation (DG) for stacked-up applications at facility or distribution network levels.

This legislative requirement and CEA Element 1 have many common elements in terms of findings. For this ESA report, we limit our interest to DERs that include ES.

[281] Stakeholder. 2019. (Comment made by stakeholder for CEA Element 8 at Energy Storage Stakeholder Meeting held on March 20, 2019. See Appendix B – Stakeholder Responses)

Element 9

Determine how to incorporate DER into the electric distribution system most efficiently and cost-effectively

Focusing only on the ES element of DERs, CEA Elements 6 and 8 address this element.

Recommendations for the Next Phase

This section presents recommendations for additional data gathering and technical recommendations for further analysis. These recommendations can also serve as guidelines for developing incentive programs for ES deployment.

- Gather/assess New Jersey-specific ES cost data.
- Installation of smart meters for improved load data collection.
- Identify pilot programs and associated incentives to study deployment of V2G and V2H.
- Establish a consensus value of avoided T&D costs for use in further analyses.
- Establish consensus-based interconnectivity data for research use.
- Further study of integrating ES into OSW.
- Development of Community Affairs – related items like ES siting, zoning, permitting, building codes, ordinances, best practices, "plug and play" models for municipalities, first responder & code official training/awareness/Standard Operating Guidelines (including for Electric Vehicles).
- Evaluation of economic opportunities, such as reuse of Li – ion battery (testing/reconditioning/repurposing).
- Pilot testing of early stage battery technologies/chemistries (flow batteries, NaS, etc.), with preference for New Jersey-based companies.
- Implications of FERC Order 841 and associated PJM Tariff on ES in New Jersey.
- Further benchmarking other state programs.
- Further clarification of state plans for storage capacity and duration.

CONCLUSION

This technical analysis of ES shows that it can play an important role in New Jersey's sustainable energy transition. New opportunities are arising to apply mature technologies and gain experience with emerging technologies in the service of a cleaner, more resilient, and more cost-effective electric power system. These opportunities await at the bulk power level, distribution system level, and behind-the-meter at customers' sites. Pumped hydro and thermal storage are already in widespread use. Electrochemical battery technologies are beginning to find cost-effective applications, with Li-ion the current leader. Batteries cost-effectively provide ancillary services to the bulk power system. They hold near-term promise, as costs come down, to help increase hosting capacity for decentralized solar PV on certain distribution systems; and increase resilience in combination with solar PV on the customer side of the meter for high-resilience users such as hospitals, hotels, and supermarkets. With further cost reductions, ES can help with grid stabilization for OSW projects and EV charging stations. ES can enable several of the key transformations needed to support New Jersey's energy economy, and policymakers have the necessary tools to encourage wider deployments. Fair and efficient policymaking will encourage adoption of ES technologies in applications where they are cost-effective and well suited, while incentivizing emerging, game-changing applications that may soon become feasible. As with any policy that has transformative aspirations, a key aim should be learning from experience, and adapting both means and ends as evidence accumulates. This report provides a starting point in that continuing process.

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Rutgers Laboratory for Energy Smart Systems (RU LESS) has been tasked to analyze sizing, location, resiliency and network impacts of energy storage. The RU LESS team consists of Mohsen Jafari, Kashayar Mahani and Ali Ghofrani. RU LESS just completed a project for NJ BPU on microgrid evaluation and has an ongoing project with the agency on off-shore wind.

The Bloustein School has been tasked to conduct the economic assessment of storage. This part of the Project Team consists of Clinton Andrews, Will Irving, Francis Jordan, and Jasci Trazska. The Bloustein School has recent and ongoing projects with the NJ BPU related to community solar, energy efficiency evaluation, the Regional Greenhouse Gas Initiative, and offshore wind.

The Materials Science and Engineering (MSE) Department and The Energy Storage Research Group at Rutgers have been tasked with conducting an assessment of different available technologies that might be deployed for ES in New Jersey as well as evaluating the impact of ES on Electric Vehicle adoption in the future. The MSE Project Team consists of Glenn Amatucci, Nathalie Pereira, and Dunbar Birnie. The MSE team members have a number of recent and ongoing projects related to various battery studies relevant to the current goals. The Energy Storage Research Group at Rutgers University is a diverse team of faculty, professional staff, and students focused on advances in a broad spectrum of electrochemical energy storage ranging from advanced electrode materials to novel cell engineering.

The ESA Research Project Team acknowledges the participation and comments of the many stakeholders who provided input. Special thanks to ICHPS, Pepco, PSE&G, Energy Storage Association, CALMAC, and NREL.

APPENDIX

The Appendix appears in a separate file: [New Jersey ESA Appendices 5-23-2019].

The Appendix includes the following:

- Appendix A – Stakeholders' Surveys
- Appendix B – Stakeholders' Responses
- Appendix C – Element 3: Supporting Materials
- Appendix D – Additional Benefit-Cost Sensitivities and Capital Costs

New Jersey Energy Storage Analysis (ESA)

APPENDIX

By Rutgers, The State University of New Jersey
May 23, 2019

Table of Contents

APPENDIX A – Stakeholders' Surveys

In February 2019, Rutgers organized an Energy Storage (ES) Stakeholders meeting with more than seventy participants from public and private companies to introduce the Energy Storage Analysis (ESA) project and receive the stakeholders' feedback to improve the analysis. Third party suppliers, energy distribution companies (EDC), and PJM were invited and participated in the meeting. A survey form was distributed among the participants before the meeting to collect industry opinion on technology cost/parameters, and suggestions regarding the study. The survey was designed to address the following main issues:

- Applications that will have the most practical business appeal during the next five years.
- Energy storage (ES) methods and technologies that are most likely to be used in various applications.
- What performance criteria, costs, and benefits should New Jersey use to assess ES projects? Which are plausibly measurable?
- What factors should policymakers consider when designing an ES program for New Jersey to ensure that ES development has a reasonable business model?

The summary of concerns and comments made by the workshop attendees follow:

- In response to ES applications and application regulations, an attendee from PJM commented that large scale ES systems, in front of the meeting applications, and hybrid renewable/storage systems are crucial for PJM.
- Incentives and localization of benefits were suggested to help proper ES allocation and effective applications.
- Power applications or energy applications need to be clarified. For ES power applications, seasonality is suggested as an important factor (e.g., solar power availability during the cooling season and high grid stress during the heating season in the Atlantic City Electric (ACE) territory).
- Solar ES and the application of ES in the offshore wind plan are also of paramount importance. It was suggested to model increasing levels of Offshore Wind from 1,100 MW to 3,000 MW between now and 2030 assuming that the higher levels are produced across the tri-state area to evaluate the impact on Offshore Wind plan.
- In renewable firming for capacity, the usage of ES systems is important to reduce kW supply charges, due to recent tariff changes reflecting network integration services (NITS) fees, transmission enhancements and capacity, for C&I customers.
- A storage device could be co-located with existing solar to achieve a result similar to upgrading diesel and natural gas generators. Solar is intermittent, and storage could be sized to firm up solar capacity for 3 or 4 hours in an attempt to reduce these obligations. The storage device could also be used to provide a resilience function. While net-metering

provides solar owners with kWh charge avoidance, a solar + battery hybrid system could provide owners with kWh and kW charge avoidance.

- There would also be a societal benefit as these systems would reduce peak load. A solicitation should be developed to add ES to large solar electric systems to have the most near-term impact on reducing emissions during peak hours. To start, there are about 560 MW of grid supply systems in operation that could add storage to firm their capacity (with PJM) and earn capacity credits.
- Interconnection of storage would likely be the least expensive per MW of any storage sector and could be accomplished faster because interconnection is already in place for the capacity of the solar farm. Because peak generations emit two to three times as much global warming pollutants as baseload, it would have the largest impact on emissions per MW.
- For more effectiveness of ES applications, ES access regulations should be modified and retail/wholesale value of storage systems with the same resource should be evaluated for different use cases such as ES participation as demand response resource ancillary services and storage access to export to the grid as a generator have to be evaluated thoroughly.
- Multiple applications were suggested to be considered in use-cases for economic impacts. In addition to frequency regulation, arbitrage, and capacity markets, other ancillary services can be customized for ES applications.
- Sensitivity analysis regarding the ancillary services price was suggested to be included in the analysis.
- Interconnection agreements and utility constraints in wholesale markets should be considered or revised for ES applications. One scenario that PJM is working on is the possibility that ES charges at retail rate and discharges in the wholesale market in compliance with Federal Energy Regulatory Commission (FERC) order. However, the uncertainty of market instruments and the value streams associated with energy storage need to be included in the analysis.
- In industrial and large-scale applications such as New Jersey Transit, frequency control is hard due to the dynamic behavior of loads (trains). Energy storage can help to balance such systems to maintain frequency constraints. Using the approach outlined in the Sandia paper is suggested to frequency regulation.
- Solar/Storage residential applications are also among important cases that are in need of certain regulations.
- One other application of ES systems is the use of ice storage technologies for curtail peak loads associated with residential and commercial air conditioning systems. These peak demands are significant, and ES has the potential to benefit the grid by mitigating such aggregate peak demands.
- For more effective ES utilization, the software is another important factor.
- Combination of ES and hydrogen fuel cells is suggested as another application that can improve New Jersey's resiliency.
- The questions of how ES can help electrification of transportation and how it can mitigate the future stress derived from EV fast chargers are among important facts that need to be taken into account.

- The impacts of Vehicle-to-Grid (V2G) and Vehicle-to-Home (V2H) techniques and technologies should be evaluated. It is suggested that daytime charging from renewables and evening discharge will make a huge dent in the development of the Duck Curve.
- In response to technology aspects of ES, modeling a Policy Toggle switch for Net Energy Metering (NEM) and non-Net Energy Metering scenarios are suggested. This may be the best way to identify those social costs and benefits created by the NEM policy currently in place. When preparing the model, it would be most helpful to model 100% self-consumption, then varying amounts of curtailed energy to observe how the benefits are affected.
- Further, modeling of some restricted NEM may also be interesting. In this model, NEM would be restricted to a certain amount of energy daily that could be fed to the network, the balance being either stored or curtailed. Application of smart metering and how to help form the future grid, reaction of storage, and load shaping are considered as other technological aspects of ES.
- In response to performance criteria measures, it is suggested that T&D deferral is among the most important measures to be taken into consideration.
- Temporary usage of ES can defer the infrastructure upgrade for three-four years.
- Resiliency performance measures should be well defined.
- Environmental justice performance measures and if ES allocation can create economic development and jobs in New Jersey, and geographic/environmental challenges are among other important performance measures that are suggested to be taken into account.
- ES services such as demand charge reduction and market participation require warranties granted by the authorities.
- ES application processes should be standardized in New Jersey and PJM territories to absorb more participants to participate in the market.
- New tariff compensating voltage support and environmental concerns are also suggested to be considered.
- In moving ES forward through policies to accelerate deployments, it is important to consider the infrastructure in place to provide for public safety from the development of standards and codes to their adoption and then documenting and validating compliance. It is suggested that New Jersey implement efforts to update the adopted codes/standards and help those responsible for compliance apply and enforce those codes.

APPENDIX B – Stakeholders' Responses

Item 1. How might the implementation of renewable electric energy storage systems benefit ratepayers by providing emergency back-up power for essential services, offsetting peak loads, providing frequency regulation and stabilizing the electric distribution system?

1. PSEG - Renewables and energy storage can be deployed at critical facilities to provide resiliency services. In its "Clean Energy Future: Electric Vehicle and Energy Storage" filing ("CEF-EVES"), PSE&G proposed piloting four Community Microgrid projects which will incorporate energy storage with solar energy to allow critical community facilities to operate independent of grid power during an extended outage. The electric distribution companies ("EDCs") should continue to study microgrid deployment models as they could be well-suited to provide resiliency solutions to customers, either via traditional grid power or through the utilization of microgrids.

2. CEG - Energy storage on both sides of the meter can provide a range of benefits. Applications can often be stacked so that a single renewable-storage system provides multiple benefits both to the customer and to the larger electricity system (the grid). However, this ability to stack applications can be either supported or hindered by market rules and regulations. It is important for states to consider how rules and regulations can best support and optimize the range of benefits storage can provide, especially but not limited to the monetizable benefits. To achieve this, the state needs an overarching storage initiative that requires collaboration between different involved agencies and regulatory bodies, so that rules and regulations work together across various programs and dockets. Please reference attached filings in MA NEM and capacity market dockets, as well as upcoming CEG report on storage in energy efficiency programs.

3. DER - It is somewhat cliché, but it is nevertheless true that the electric industry is undergoing significant transformation. Driven by technological changes, changes in the resource mix, the need for greater grid security and resilience, and the desire by some ratepayers to more actively manage their energy consumption and production, electric energy storage can play a vital role in facilitating sustainability, system resilience, and more efficient energy cost management.

   Electric energy storage when paired with renewable energy resources such as solar, can promote system resiliency by ensuring that there is an uninterrupted power source in the case of outages on the electric distribution system. The paired energy storage/renewable generation system can be part of a microgrid serving a local community, or it could be a form of back-up generation used by a single customer during an outage. Having a paired energy storage plus renewable generation system can mitigate the impact, including any economic impact from disruptions of service, or outages on the electric grid.

Key to the widescale adoption of electric storage systems is the economic benefits or economic payback to be derived from such systems. In order to facilitate broader adoption and investment in these technologies, there needs to be an economic incentive to invest. With the appropriate regulatory constructs for instance, ratepayers can potentially see economic benefits from the use of their electric storage systems to manage demand charges through offsetting peak loads.

More broadly speaking, there also needs to be consideration of multiple use applications for these electric storage systems. This includes how to fairly compensate owners for those multiple uses, while preventing duplicative payments for the same service. For instance, if a storage system is providing distribution services as well as wholesale services, how should market rules and tariffs be defined to clearly demarcate jurisdictional boundaries/markets, and how services are valued and compensated in each jurisdictional market?

4. NJDRC - Renewable electric energy storage has the potential to enhance the efficiency, resiliency and affordability of the electric grid. It can provide multiple benefits such as balancing short- term power fluctuations, offsetting peak demand, and providing back-up power in emergency situations. Electric generation and demand must always be in balance to ensure a consistent and reliable power supply, so as more intermittent, renewable generation comes on line, it becomes increasingly difficult to maintain this balance. In addition, most renewable installations only generate power when the sun is shining, or the wind is blowing. Energy storage technologies can provide the flexibility to manage and use the generation from intermittent renewable resources at any time of day. It also allows for energy generated during low cost off-peak periods to be used during more expensive peak periods, thus improving the efficiency of the electric grid. Electric storage can also assist with emergency back-up services in the event of an outage. Energy storage opportunities may also provide financial benefits to ratepayers by reducing electricity prices, lowering peak demand, potentially deferring utility investment in new capacity as well as transmission and distribution, and increased reliability.

   However, Rate Counsel cautions that a comprehensive study is needed to evaluate the overall need for storage within the state, the costs of various storage technologies and the quantifiable benefits these technologies would provide. Rate Counsel looks forward to reviewing the analysis prepared by Rutgers and specifically the estimates of storage technology costs and benefits.

5. OCE - Many studies have been done attempting to quantify the types of benefits that this question asks about. It is not really possible to generalize from studies done elsewhere about how valuable storage will be in New Jersey. But storage can be cost effective for owners and operators under a number of different use case scenarios, and typically means operating the system for one primary purpose (e.g. offsetting peak loads) and using it to provide other services when not otherwise in use for the primary purpose.

Green Mountain Power's Tesla powerwall program (https://greenmountainpower.com/product/powerwall/) and liberty's program (https://www.concordmonitor.com/libert-utilities-storage-electricity-battery-hanover-nh-21659098) are examples of storage programs that provide benefits to both utilities and their customers.

6. VES - Energy storage systems when combined with solar can help provide emergency back-up power during disasters as well as a host of other benefits such as reduced peak loads, energy cost savings, reduced demand charges, and other ancillary services.

   Emergency back-up power

   The benefit of emergency back-up power is more profound for low-income and EJ communities. Unlike wealthier households who may be able to relocate temporarily after a disaster that disrupts power, low-income households may not have the ability to do so. Solar when combined with storage can provide long-duration backup power that can support housing and other critical facilities and allow first responders to serve residents.[3]

   States such as Massachusetts through its Community Clean Energy Resiliency Initiative demonstrate how solar plus storage microgrids can provide resilient power services to critical community facilities such as police stations, hospitals, public shelters, and water treatment facilities.[4]

   Energy Cost Savings

   Studies show that low-income households spend up to 7% of their income on energy costs whereas non low-income households spend 3% of their income on energy costs.5 Given the high disparity between the low-income and non-low-income households, ensuring energy cost savings for low-income and EJ communities should be a public policy imperative.

   Solar PV can help provide energy cost savings to LI households by stabilizing and often bringing down electricity bills. Solar PV coupled with energy storage can be even more beneficial, because energy storage can be deployed to reduce demand charges for commercial electric ratepayers.6 In most cases, multifamily affordable housing facilities fall into this customer class. Deploying solar and storage for multifamily affordable buildings can offset a large portion of energy costs. The savings can be used to reinvest in a building, or to invest in more affordable housing.

   New Jersey has seen the effects of reducing demand during peak times. Solar plus storage deployment can have a similar effect as demand response, resulting in less peak demand, lower peak prices, lower need for expensive peaker plants, less need for more transmission, and overall cost savings for all ratepayers.

7. OMNES - Efficient low-cost energy storage systems benefit NJ ratepayers in several ways.

According to the Sandia Labs report [USDOE Sandia Laboratory SAND2010-0815] prepared by Sandia Laboratories for the U.S. Department of Energy (DOE), energy storage applications can be divided into five categories: electrical supply, ancillary services, grid system applications, end-user/customer applications, and renewable energy integration.

8. INGER - Energy storage technology can provide multiple benefits to electric customers in New Jersey. Because storage can stack services (i.e. take on onsite generation / demand response, distribution, transmission and generation-like functions depending on need), it reduces the need for single purpose assets on the electric grid. As a result, energy storage technology can be a cost-effective way to improve the efficiency of New Jersey's grid.

   Trane delivers TES through its CALMAC portfolio in Fair Lawn, NJ. TES is best known for peak load reduction, grid services, demand response, and back-up cooling.

9. JCPL - The strategic deployment of energy storage technology on the transmission and distribution systems of electric distribution companies ("EDCs") can have a positive impact on service quality and the reliability of their systems. This positive impact can result from strategic deployment of all different kinds of energy storage resources and not just renewable electric energy storage systems. In addition to the benefits storage technology can provide as an emergency back-up power source to support transmission or distribution system operations, it also provides benefits as a voltage regulation tool. Like other advanced distribution system infrastructure, storage technology can respond instantaneously to changes in voltage, resulting in a more stable, reliable distribution grid. Indeed, appropriately managed storage technology can play a role in regulating the voltage on the EDCs' distribution systems as distributed energy resources ("DERs") deploy and inject excess electricity onto the grid. Energy storage technology can also play a role in potentially improving voltage profiles during periods of high loading and reducing peak demand on transmission or distribution equipment. In short, the strategic deployment of energy storage technology can benefit the EDCs' transmission or distribution systems and has the potential to benefit their customers.

   New Jersey's EDCs are in the best position to optimize the value their customers may realize from the deployment of energy storage technology as a transmission and distribution asset. The key is strategic integration of these technologies. Customers benefit most from energy storage technology when it is strategically placed onto the EDCs' transmission and distribution systems to increase reliability and defer otherwise necessary investment in upgraded infrastructure. The expertise and knowledge the EDCs' possess of their unique systems make them best-suited to identify the areas where these strategic investments will provide the most benefits to their customers. As such, the Board should recognize the vital role the EDCs will play in optimizing the benefits customers realize from New Jersey meeting its energy storage objectives.

10. NJCF - As discussed above, a variety of energy storage technologies would be needed to provide the various services needed as the state progresses towards its clean energy goals. Further, each service requires specific combinations storage operating characteristics, and may also require its own unique battery management system and interface with the customer, as well as potentially with the electric distribution system, and with the wholesale electric market. Thus, realizing net benefits from the storage will require the right choices among all these options. In some, and perhaps most storage applications, these choices will be made by private parties, who will then bear the bulk of the costs and benefits, and who will naturally seek to ensure their benefits exceed their costs. If, however, any of the benefits of the storage systems that accrue directly to ratepayers are greater than any of their costs borne directly by ratepayers, storage systems that are more cost-effective than their alternatives will benefit ratepayers.

11. NJR - Storage is a transformative technology that can enable an efficient, resilient, flexible and clean electric grid and change operating and business models in the electric utility industry.

    With the ability to shift loads from peak to off-peak periods, storage has the potential to reduce costs and inefficiencies in an electric system designed and sized to meet peak demand. Storage can also be an enabler of a variable resource grid, providing flexibility to balance the output and improve utilization of intermittent renewables.

    Reflecting current costs, market prices and market structures, the storage market today is in very early stages, with less than 1 gigawatt (GW) of installations in the United States representing less than 0.01 percent of total generating capacity. To support storage growth and meet its goals of 600 megawatts (MW) by 2021 and 2 GW by 2030, New Jersey will need to provide financial incentives to encourage market development.

12. MSS - Offsetting peak loads – customer side, FR and DR – wholesale, grid side.
    Can generate revenue, reducing or eliminating the need for incentives to drive the deployment of storage in order to comply with the requirements of the act Emergency backup power for critical facilities is a capability that energy storage facilities are uniquely suited to provide. Batteries are more reliable than engine-generators. They can come on line and respond to load much more quickly too, and can provide and maintain very high power quality. When used in conjunction with solar power, they offer backup power without dependence on external sources of fuel that can be affected by extreme weather events (when the emergency power is needed most). When batteries are used in combination with both solar power and engine generators in microgrid mode, very high reliability can be achieved as each of the sources exploits its own strengths while covering the weaknesses of the others.

13. SP - Emergency Back-up Power for Essential Services
    Energy storage systems can be used in place of, or as a supplement to, traditional backup generators (diesel, natural gas, etc.), and have the added benefits of zero on-site greenhouse gas (GHG) emissions with virtually instantaneous dispatch. However, as

energy-finite resources, energy storage systems cannot be relied upon solely to provide back-up power for extended periods of time (e.g., 12+ hours). Additionally, it is not possible to "stack" the benefits of energy storage backup power with other use cases for individual energy storage systems. Energy capacity reserved for back-up power cannot be used, for instance, to provide grid services or peak load shaving, in that an emergency event may occur immediately after an energy dispatch event for another use case, at which time a storage system may be too depleted to perform its emergency power obligation.

For these reasons, emergency back-up power should not be a blanket requirement of all energy storage systems participating in a state-sponsored energy storage program. Owing to the opportunity cost of performing back-up power services, a separate funding source should be established to enable energy storage back-up power systems to be deployed cost-effectively. Developers of energy storage systems should also be given the opportunity to provide emergency back-up power during specific windows of time, rather than all hours, in exchange for a prorated share of emergency back-up power funding. For instance, a developer may choose to provide back-up power for an essential services facility during the months of January – June, or during the hours of 8 p.m. – 8 a.m., and in exchange would receive half the emergency back-up power funding as an energy storage system providing back-up services during all hours of the year. This will enable developers to make informed business decisions about the provision of emergency back-up power without entirely foregoing other storage use cases.

Offsetting Peak Loads

Energy storage systems can be very effective in offsetting peak loads for specific pre-determined durations. Energy storage systems have unique advantages regarding response time and the ability to closely match power dispatch to variations in load, and so are particularly useful in accommodating dramatic swings in load and covering absolute load peaks (e.g., candidate hours for the PJM 5 coincident peak hours). However, the energy-finite nature of energy storage systems makes them less well suited to coverage of peak events that are protracted or subject to great variations in length of time.

Any state program framed around energy storage systems providing peak load offset should take advantage of energy storage devices' intrinsic dispatch speed and operational flexibility while mitigating their relative shortcomings as energy-finite resources. Program designers should also keep in mind that the very highest peak hours (e.g., PJM 5 CP hours) are extremely costly to ratepayers relative to other hours of the year, and so peak load coverage via energy storage is subject to diminishing returns. For that reason, we recommend that a storage peak load offset program have a short runtime requirement (e.g., 2 – 4 hours), or otherwise conform funding to an approximation of peak load offset value relative to maximum power and energy capacities. We would refer program designers to methodology used to calculate the Energy Storage Adder as part of the Solar Massachusetts Renewable Target (SMART) program.

Similar to the compensation structure for energy resources participating in capacity markets in PJM and other ISO/RTO's, peak load-offsetting energy storage systems should be paid for their availability to perform during peak periods, rather than on a $/MWh energy dispatch basis. This is because peak loads are variable within reasonably predictable hours, and so resources should be held back until they are determined to be necessary to mitigate actual peak events, while project developers and investors rely on predictable revenue streams when making business decisions about where to locate resources. In order to accommodate both interests, program designers could establish certain peak windows (e.g., 2 – 6 p.m.), during which resources would be available to dispatch up to their nameplate energy capacity at the direction of program administrators.

Providing Frequency Regulation and Stabilizing the Electric Distribution System
Frequency regulation was one of the first and most successful use cases for energy storage systems in the United States, particularly in PJM. However, because of the relatively small size of the frequency regulation market (1% of the annual cost of the PJM capacity market) and the very high compensation rates of FR market participation for a period of time, the market proved unreliable as a sustainable core revenue stream for ongoing storage project development. Any state-level program designed to support the enrollment of energy storage systems in PJM's regulation market should seek to mitigate the volatility of participation in that program.

Because PJM's Frequency Regulation program is geared toward supporting grid stability at the transmission level, program designers may consider a separate program design specific to frequency regulation the distribution level. Distribution grid conditions can vary substantially from substation to substation and even circuit to circuit, so program designers may consider implementing specific non-wire alternative (NWA) solicitations for areas of the grid in which storage may prove a viable and cost-competitive alternative to traditional grid upgrades, similar to the programs implemented in New York State. However, for these NWA solicitations to be effective, they would need to be well-scoped (specifically defined energy capacity, power capacity, and point of injection requirements) and long-term, with a cost-to-compare in excess of 10 years, as traditional solutions are generally evaluated on a 20+ year life cycle. Prospective bidders should also be given information on the cost of a traditional upgrade to address grid stability, so they can make informed business decisions about the scope and types of energy storage solutions to offer on a competitive basis.

14. RECO - Energy storage has the potential to transform how EDCs plan and operate their electric distribution systems. The value of energy storage systems is in their ability to provide benefits across the bulk and electric distribution systems, as well as directly to customers. A single energy storage system may be able to provide peak load management, resiliency benefits and frequency regulation services simultaneously, thereby enhancing the cost-benefit relationship.

    In addition, storage technology is dispatchable, allowing energy to be discharged when required, e.g., during peak load relief for both in front of the meter and behind the meter

("BTM") applications. For example, customers on demand rates with BTM storage assets can manage their peak usage thereby lowering their energy costs by managing their demand charges. Moreover, customers with BTM storage systems can discharge the stored energy to support emergency needs. Likewise, both BTM and in front of the meter storage assets may allow deferral of an EDC's distribution system infrastructure upgrades, thereby providing cost savings and resiliency for all customers. In addition, reducing peak usage by dispatching energy storage during high system load conditions provides system-wide and societal benefits by reducing overall capacity obligations.

The Company recommends that the Board seek energy storage deployments that provide benefits to all customers by focusing initial programs and incentives on bulk and distribution level energy storage deployments. To encourage retail uses, the State should develop programs that tie retail BTM storage with demand response programs and the appropriate rate design. At the same time, the Board should consider allowing EDCs to deploy storage technologies in a sampled manner in order to test novel business models, learn valuable lessons, and support the progress towards reaching the State's Clean Energy Act goals. Results achieved from this demonstration-type approach can be used to evaluate the validity of defined hypotheses and apply lessons learned in order to inform State regulatory policy.

15. TESLA - For end-use electricity customers, energy storage can provide a range of benefits to control energy costs and increase resiliency including:
    • Peak Shaving – The on-site energy storage system can discharge at times of peak demand to avoid or reduce demand charge,
    • Load Shifting – Energy storage can help shift energy consumption from one point in time to another to avoid paying premium energy prices,
    • Emergency Backup – Energy storage can provide intermediate backup power at almost any scale in the event of the grid interruption. This function can typically be standalone or paired with an on-site generating source, and
    • Demand Response – Energy storage can discharge instantly in response to signals from a demand response administrator to alleviate peaks in system load.

    Energy storage can also be a versatile grid resource that allows electric utilities to:
    • Defer or avoid costly investments in generation, transmission and distribution,
    • Enhance the integration of intermittent solar and wind renewable energy, of which NJ is one of the largest US markets, and
    • Increase the security, reliability, and resiliency, of the electric grid by:
        - Providing flexible ramping to support local and system ramping needs in a cost-effective manner,
        - Frequency Regulation, and
        - Voltage and Reactive Power Support at local and bulk power levels.

16. POWED – Peak shaving is the most valuable and beneficial energy storage service as it reduces costs attributed with peak generation and T&D infrastructure build-out.

17. SUN - There are tremendous benefits that residential or "customer-sited" solar-plus-storage can provide to customers, the distribution system and at the wholesale grid level. For individual residential customers, in the event of a power outage, a solar-plus-storage system can safely island from the grid and power the home. Solar + storage in island mode are capable of powering the home and charging the battery for backup, providing a smart form of site-level resiliency not previously available to homeowners with clean energy. The importance of back-up power for residential customers cannot be overstated. For vulnerable customers who may have serious illnesses or disabilities requiring treatment from electric-powered medical devices or refrigerated insulin, having a solar-plus-storage system at their residence can be the difference between life and death. For moderate-income working families living paycheck to paycheck, home resiliency during a severe weather event and power outage means, for example, that the food in their refrigerators does not spoil, saving them additional grocery expenses.

    In Puerto Rico, in the aftermath of Hurricane Maria, Sunrun saw firsthand the suffering and destruction caused by power outages and a fragile, obsolete energy system. Sunrun was one of the first solar companies with boots on the ground, partnering with Empowered By Light and Puerto Rico construction firm Aireko, to donate and install solar and battery systems at fire stations in Puerto Rico. Without power, these first responders would not have been able to operate or provide emergency services to members of their communities in need of urgent assistance. Since the installation of Sunrun's solar and battery systems, the systems have run uninterrupted on these fire stations. Throughout the longest blackout in U.S. history, the firefighters were able to respond to emergencies and offer vital support to their surrounding communities. The resiliency benefit of local solar and batteries is proven in the field.

    Sunrun has since commercially entered the Puerto Rico market, in partnership with local solar and storage companies. Sunrun is deploying residential solar plus storage systems, growing local jobs, and helping to rebuild Puerto Rico's grid one home at a time. Puerto Rico is similar to New Jersey in that it is ideally suited for distributed solar plus batteries as a jurisdiction with limited land available. Rooftop solar combined with storage uses existing building infrastructure, keeping costs low and maintenance at a minimum.

    Further, the aggregation of residential solar-plus-storage systems into a virtual power plant provides a multitude of benefits to the grid including obviating the need for another peaker plant or transmission and distribution upgrade. This is something that Puerto Rico is considering as it rebuilds its grid. The benefits of aggregated solar-plus-storage systems also include distribution and transmission cost reductions, energy and wholesale market cost reductions, increased renewable energy integration, resource adequacy, peak reduction, and ancillary services. Indeed, there is a general recognition that maximizing the benefits energy storage can provide requires the "stacking" of value streams at the customer, distribution, and bulk system or wholesale level. This requires coordination of the operation and control of storage devices so that they can be used to provide multiple services (i.e., "multi-use applications" or "MUAs") without creating conflicts between the provision of one service and another. Customer-sited energy storage is considered to have the most potential value because it allows benefits to be created within all three domains.

18. SUNOWNER - Solar Residential Electric Storage systems benefit ratepayers by providing electric power during grid interruptions, however short or long. I have lost work many times when the electric went out even for short periods. Longer outages can be supplied by solar and storage for multiple days, providing light, heat and refrigeration to avoid food spoiling. Adoption of storage by some of the 100,000 residential and commercial solar systems can be linked together to displace some of the old carbon emitting peaking generators we rely on today during peak demand hours, and reduce carbon emissions while stabilizing the grid. Storage can also provide capacity and ancillary services and respond more quickly than conventional generation and thus is more valuable than turbine based generators.

Item 2. How might the implementation of renewable electric energy storage systems promote the use of electric vehicles in New Jersey, and what might be the potential impact on renewable energy production in New Jersey?

1. PSEG - Energy storage has the potential to enable more site locations for the deployment of DC fast charging stations, which will promote the use of electric vehicles ("EVs") in New Jersey. Due to their role in providing high-powered, quick charging to customers, DC fast chargers can utilize a significant amount of capacity on a circuit. Deploying energy storage alongside these sites could reduce the peak demand, mitigating both capacity demands on the circuit, and customer demand charges. For these reasons, energy storage may play an important role in the expansion of electric vehicles in NJ. PSE&G has proposed piloting energy storage with DC fast charging sites in its CEF-EVES program.

2. CEG - Storage should support the deployment and integration of renewables. Many PV installers are now adding storage to their product lists. Storage is important to add because of the duck curve problem first seen in CA and now appearing in New England as well. The peak shifting ability of storage should be incentivized so that more solar does not cause ramping problems. This can be achieved by a variety of policy tools including performance incentives, TOU rates, demand charges etc. but needs to be done with the performance attributes of storage in mind. For example, defining "peak" as all daylight hours is not useful, as this tends to decrease the value of any given "peak" hour to the point where storage is no longer cost-effective. A better alternative is to define "peak" as the top 10% of hours of the year, either based on demand or price. See upcoming CEG report on storage in MA EE plan.

   EV use has run into a barrier in the form of high demand charges being levied on EV fast chargers in many areas of the country. This can be addressed by the addition of stationary energy storage at fast charging stations, so that the fast charger load is less peaky. The addition of energy storage at charging stations also confers a resiliency benefit in that EVs can charge when the grid is down. And home batteries, in conjunction with solar, allow EVs to be charged from PV even at night, meaning that homes can use excess PV generation where NEM caps have been reached.

3. NJDRC – The intent of this question is unclear to Rate Counsel. Electric vehicles ("EV") are both users of electricity and a potential storage technology.

   As more renewables and distributed energy resources ("DER") are being installed and deployed, the electric grid is becoming more of a mix of traditional centralized power generation and decentralized power generation or technologies. One of these decentralized technologies may be EV. Researchers are starting to look at the use of EVs as potential mobile energy storage units in that EV s consume electricity when they are being used, but could also export their stored power back to the grid, or provide back-up power during outages and emergencies. Again, quantifying the benefits of using EV s as mobile storage would require a comprehensive study of the overall need for storage within the state, the cost of EV technologies and implementation throughout the state; the upgrades needed to EV charging stations and the quantifiable benefits this technology would provide. Rate Counsel looks forward to reviewing the analysis prepared by Rutgers and specifically the estimates of storage technology costs and benefits.

4. OCE - The imposition of demand charges where DCFC is considered a significant barrier as EV markets get off the ground. Storage systems may be one way to avoid the high demand from certain fast EV charging, and the associated demand charges.

5. OMNES - Energy storage provides definite benefits to electric vehicles especially with respect to transportation fleets. Impact on renewable energy production will depend on volume.

6. JCPL - A future with widespread electrification, including extensive use of electric vehicles, could benefit from energy storage available on the distribution system. Energy storage is a versatile resource that can be used for multiple purposes. For example, it could possibly be used to provide flexibility that is needed to accommodate increases in load during peak and non-peak hours, assisting with increased load due to electrification generally and the electrification of the transportation sector specifically.

7. NJCF - As discussed above, energy storage has the potential, if technologies with the right operating characteristics, performance and costs are available and implemented, to help make high speed EV charging less expensive and more commercially attractive and more available. However, this depends on the cost of such storage-enhanced systems being less than that of pure "wires-based" charging systems. Similarly, appropriate levels and types of energy storage could result in less curtailment of renewable energy production in the state, if the state were to develop enough in-state renewable energy production to exceed, at particular times, its own demand plus export capability to other parts of PJM. Storage could also help alleviate conflicts between state clean energy resources, such as high levels of offshore wind production during cool nights with low demand, coincident with high levels of nuclear output from the state's remaining nuclear reactors. If the combined output of these resources exceeded demand within the state, and exceeded either export capability or demand within the region, one of the two clean energy resources would need to be curtailed to prevent overproduction. But to know whether any of these situations are likely, whether they would be helped by storage, and what types of storage, in what amounts and in what locations would be cost-effective in terms of avoiding any such curtailments, will require the kind of analysis and planning recommended in these comments.

8. NJR - Both stationary and mobile batteries in electric vehicles (EVs) can complement a variable resource grid with a high penetration of intermittent renewables. If properly integrated into the grid, mobile batteries have the potential to augment and even displace the need for some stationary storage. Early trials in the U.S. and Europe demonstrate that mobile storage has the potential to be recycled and reused as stationary storage devices.

Stationary storage also has the potential to provide mobile storage devices with more flexibility and options. These synergistic effects can be better understood once the penetration rates of these technologies, along with renewables, increase from the relatively insignificant levels of today. Vehicle-to-Grid (V-to-G) and Vehicle-to-Home (V-to-H) protocols have been line tested in several U.S. trials thus far and should be part of the BPU's early policy and planning endeavors with respect to battery storage.

9. MSS - The implementation of renewable electric storage systems will promote the use of electric vehicles by mitigating the need, and the cost, of service upgrades at facilities that need substantially more power in order to add electric vehicle charging stations. Multiple charging stations, or charging stations for heavy duty vehicles, can bring about the need for large amounts of additional power during peak EV charge times. Further, in order to make electric vehicles a practical choice for most New Jersey citizens, charging stations will trend toward fast chargers that draw very high levels of power. Behind-the-meter stationary energy storage assets, in addition to providing many other valuable services discussed elsewhere in this response, can be discharged to reduce a facility's peak EV charging demand, thus reducing or possibly eliminating the need for expensive service upgrades.

   Even more importantly, the "rolling" battery capacity that will be embodied in New Jersey's future electric vehicle cohort can be used with bi-directional charging to help provide the necessary storage to enable large amounts of intermittent renewable energy on the grid, and to assist in maintaining reliable electric service. This vehicle-to-grid, or V2G capability is expected to be a massive asset, eventually dwarfing stationary energy storage capability (see the answer to Question 9, below). Taking advantage of this vital and cost-saving asset base will require planning, especially for an emphasis on bi-directional charging infrastructure with the attendant communication and software capabilities. It will also require cooperation from electric vehicle manufacturers.

10. SP - In the next 10+ years, New Jersey and the rest of the region and nation are likely to see substantial changes in system load behavior due to the electrification of the vehicle fleet. New Jersey has the opportunity to plan for this change through the programmatic support of the development of renewable energy resources paired with energy storage systems to meet the additional demand for electricity caused by EV charging.

    Changes in load patterns will be one of the largest impacts of increased EV deployment. We do not yet know how those load patterns will change, since EV charging infrastructure has largely not been deployed. EV charging stations at commercial locations (i.e., offices, shopping malls) could lead to an increase in daytime load. EV charging stations at residential locations (single- and multi-family homes) would lead to increases in late afternoon, evening and overnight load. Energy storage deployment, whether paired with renewable generation or not, could be co-located with EV charging infrastructure to help off-set the increased load from charging. For increases in daytime load, renewables such as solar paired with storage could help charge EVs in order to lessen grid energy demand. At night, energy storage will be essential to any effort to minimize load curve increases, and consumers can be benefited from owning or hosting solar plus storage systems that help charge their EV.

11. RECO - Electrification of transportation is critical to achieving the State's clean energy goals. The evolving electric vehicle ("EV") market requires significant near-term investments to yield both immediate and longer-term benefits. To stimulate EV adoption, the EDCs should take a leading role in deploying EV charging infrastructure based upon customer needs balanced with system requirements.

    If EV charging is unmanaged, there is potential for increased costs to EDC customers, especially if charging occurs coincident with peak demand. EDC rates have proven to be an effective way to encourage EV drivers to charge at preferred times. As the EV population grows, this shift could also help improve system efficiency. With EV deployment in its early stages, EDCs can begin to explore effective rate design considerations, e.g., rates that send proper price signals to guide EV charging away from system peak time periods. For these reasons, the use of time-varying rates for EV charging, as well as the retention of demand-based rates for EV charging, should be considered to encourage EV drivers to charge at preferred times. Along with effective rate design considerations, pairing EV charging with both solar and storage minimizes grid impacts and provides more flexibility to the customer.

    Enhanced planning and operations capabilities are necessary to accommodate EV growth and the corresponding charging activity. Integrating storage with EV chargers should be explored as it has the potential to lower the overall load consumption of the charging site and is especially true when the storage is paired with solar resources. Storage systems can be discharged during times of high demand (i.e., during an EDC's peak loading conditions) and recharged during off-peak times. Using a storage system with EV chargers may also help EDCs to avoid the need to build additional infrastructure required to support the additional load from the EV charging location.

    In the future, EVs may have the potential to provide a variety of services back to the power grid, whether as a single EV providing backup power to a home (vehicle-to-home ("V2H")) or as an aggregation of EVs acting like a virtual power plant serving the grid in times of system need. In addition, each EV may act as a mobile energy storage system through vehicle-to-grid ("V2G") applications. Electric system reliability and resiliency may be enhanced due to the number of EVs interconnected with the grid.

12. POWED - EV charging infrastructure, especially fast chargers, will cause an increase in customer demand charge in addition to overall grid challenges, both issues can be addressed through the deployment of energy storage alongside chargers or on circuits serving chargers.

13. SUN - Batteries can increase solar self-consumption and increase renewables while smoothing out load. Electric vehicles can do many similar functions and work in concert with stationary storage. Manufacturers like SolarEdge make integrated EV chargers and

inverters to optimize the function of solar PV installation and reduce balance of system costs. Also, when residents are at home, they can set EV's to maximize charge when solar panels are producing. Sunrun believes that facilitating consumers' kitchen table conversations about solar with battery storage opens the door for interest in and adoption of EV's. Finally, the same supply chain applies for EV batteries as for stationary home batteries which creates a mutually beneficial cost-reduction curve.

14. SUNOWNER - Electric storage can provide peaking power to assist the grid in supplying peak electric needs that may arise if electric charging at peak charging periods creates new higher electric demands during certain hours. Renewable electric generation can also be stored for use in vehicle electric charging to smooth out new electric charging demands on the grid. Vehicle to grid holds a large potential to profitably interact with the grid during peak cost hours because of the growing acceptance of electric transportation and the lager capacity held in this mobile electric storage than in home based battery storage.

Item 3. What types of energy storage technologies are currently being implemented in New Jersey and elsewhere?

1. PSEG - Traditional and significant energy storage technologies are currently in use in New Jersey. For instance, the Yards Creek Generating Station is a 420 MW pumped-storage hydroelectric plant located in Warren County, New Jersey. The facility is jointly owned by subsidiaries of PSEG and FirstEnergy and has provided safe and reliable energy storage service for decades.

   Newer battery energy storage technologies have been deployed for resiliency, such as PSE&G's Solar 4 All pilot program, and for participation in PJM's frequency regulation market. PSE&G's pilot program has been utilized at (a) Hopewell Regional High School as a warming/cooling station, (b) Cooper Hospital to pre-service pediatric medicine stored in refrigerators, (c) Caldwell Waste Water Treatment facility to allow the facility to operate independently from the grid, in the event of an emergency, from one to three weeks, and (d) the Pennington Department of Public Works facility to allow township crews to refuel vehicles and maintain operations.

2. Industry standard is now lithium ion batteries. Lead acid is still out there but not gaining market share. Flow batteries are starting to show up as commercial products but lack real-world track records. In the realm of thermal storage, ice and hot water systems are well-understood technologies that offer real demand-reduction benefits.

3. NJDRC - Rate Counsel is not aware of a publicly-available source that provides a comprehensive list of energy storage technologies currently being implemented in New Jersey and other states. It should be noted, however, that energy storage technologies include low-cost options such as ice energy technologies and hot and chilled water storage, in addition to high-cost technologies such as battery storage.

4. PJM currently states that is has 5,300 MW of energy storage resources, of which 96% is pumped hydropower storage. However, it is not clear for how many hours the 5,300 MW is delivered. (Also see answer to Question 13)

5. Large Li-ion batteries have been installed in several parts of the world. These batteries use technology developed for the electrical vehicle market where low weight is required. However, the typical duty cycle in EVs is very low and applicability to utility-grade applications may be questionable. Cycle life of Li-ion batteries is only about 3,000 cycles; they are typically warrantied for only 5 to 8 years. In addition, they are sensitive to temperature fluctuations and often require conditioned space to operate.

6. Utility and power applications required much higher cycle life – 25,000 cycles or more.

7. Long-duration flywheels of the type offered by Omnes Energy meet these requirements both in high cycle lifetimes exceeding 25,000 cycles as well as provide high switching

times and high power handling capability. Flywheels are vastly superior to batteries for utility energy storage. See attached: Batteries vs Flywheels.

8. INGER - Trane/CALMAC has installed over 50 projects in New Jersey over the last 25 years, accounting for over 70 MWh of load shift. The ice tanks work in line with chilled water systems and integrated controls to create TES systems, a proven, cost-effective energy storage technology. For commercial and industrial use cases, North Carolina State University calculated the system cost of TES to be $310 per kWh, compared to more than $550 per kWh for lithium-ion batteries.[3]

   Prominent New Jersey TES projects include the following:

   - Perth Amboy School District: Two school installations in 2015 and 2016, with additional sites under consideration. Helps the district save on electricity costs.
   - West Long Branch School District: one installation in 2016. Designed for energy cost savings.
   - Rutgers Athletic Center: one installation in 2016 to mitigate spiky air-conditioning demands at their basketball arena.
   - CALMAC manufacturing facility in Fair Lawn. Thermal storage installation delivers $12,000 in annual energy savings.

   Trane is currently working on additional projects in New Jersey that should be in operation by the end of 2019. However, if New Jersey wishes to accelerate the adoption of TES and other energy storage technologies across the state, the most effective means would be to institute a prescriptive incentive for energy storage technologies, on a dollar-per-kW basis. Accelerated adoption is necessary for New Jersey to meet its energy storage goals of 600 MW by 2021 and 2,000 MW by 2030.

   The most effective incentives are transparent, front-loaded and regularly available. Transparent incentives enable customers to calculate capital costs of efficiency or demand-saving measures as compared to other HVAC options.

   Front-loaded incentives are paid following project commissioning, or after one year of monitored and verified operation. Front-loaded incentives are important because customers place a heavy discount on savings earned in subsequent years for large equipment expenditures. Although individuals readily invest in a 7-10% bond, most large customers are reluctant to make investments that yield less than a 25-33% return on investment, which equates to a 3 to 4 year payback. This reluctance often reflects public sector budget constraints and private real estate owner short-term tenancy.

   Readily available rebates accelerate demand because customers that have regimented capital planning processes, such as public entities and mission-driven organizations like schools, hospitals, and universities, are able to take advantage of incentives when replacing equipment. They are less well-equipped to participate in lengthy RFP processes that may have uncertain outcomes.

9. JCPL - According to the Department of Energy's Global Energy Storage Database, only a limited number of grid-connected energy storage resources are currently operational in New Jersey.[1] Yards Creek storage facility, which is jointly owned by JCP&L and Public Service Enterprise and Gas, is the largest energy storage facility in the state, with three (3) 140 megawatt pumps/turbines that can produce 420 megawatts for approximately five (5) hours.

10. NJCF - NJCF has no specific information on this question regarding New Jersey. Please see the resources cited in the Appendix draws on for an overview of storage technologies, key physical and operating characteristics, and applications for which they are most suitable.

11. NJR - Over the past five years, energy storage installations in the U.S. have been dominated by battery storage technologies. The following battery storage market data is sourced from the U.S. Energy Information Administration (EIA) and IHS-Markit.

    • In total, the U.S. has approximately 1 GW of battery storage installed.

    - Nearly 450 MW were installed in the U.S. in 2018
    - 85 percent of all global battery installations in 2018 were lithium-ion technology
    - 60 percent of projects have less than one hour of storage duration, only six percent support more than three hours
    - 88 percent of systems participate in frequency regulation markets, with PJM as largest market
    - Approximately half the systems are co-located with renewables, primarily solar
    - There is a relatively even distribution between transmission, distribution and behind-the-meter projects

    • New Jersey has 7.3 MW installed, with 40 MW in late-stage planning or construction.

    In addition to battery storage, there are other emerging storage technologies in development. Trials of Power-to-Gas (P-to-G) technologies and protocol development are ongoing in California and Western Europe to determine the effectiveness and costs for seasonal storage. The expected advantage of P-to-G storage is to gain resiliency through diversity of distribution utilizing existing infrastructure while maintaining a low/no carbon outcome.

12. MSS - Grid-connected energy storage systems currently deployed in New Jersey, to our knowledge, include:
    1. Grid-scale, commercial-scale, and residential-scale battery systems;
    2. Electric vehicle batteries with vehicle-to-grid capability
    3. Pumped hydro storage (Mount Hope Hydro)
    4. Ice storage systems

5. Hydrogen energy storage in conjunction with electrolysis and fuel cells

Elsewhere, other notable energy storage systems include:

1. Compressed air storage
2. Flywheels
3. Ocean pumped hydro
4. Molten salt storage
5. Hot water and chilled water storage

13. SP - In NJ and elsewhere, the majority of new energy storage resources in implementation or development are based on lithium ion cell technology. Exact chemistries vary by manufacturer (e.g., Li-cobalt, lithium manganese oxide, lithium iron phosphate, etc.), each with a different set of operational characteristics and ancillary system designs (e.g., containers, cooling systems, controls, etc.), but the core technology is the same in most commercially deployed systems. We look forward to more nascent storage technologies (e.g., flow batteries) are achieving commercial availability and economic viability in the coming years.

14. RECO - To date, RECO is aware of only two batteries installed in its service territory – both on residential customer premises. Less than a dozen more – also located at residential customer premises - are in various stages of the interconnection process. All of these are lithium-ion ("Li-ion") battery systems.

    RECO's New York affiliate, Orange and Rockland Utilities, Inc. ("O&R"), is currently working with energy storage developers to build energy storage systems in its service territory. To date, these proposed systems are also Li-ion battery systems, driven primarily by the low cost of Li-ion batteries and the short-to-medium length duration of the storage applications. O&R's experiences are resulting in valuable knowledge that will provide a foundational base from which RECO can draw to deploy energy storage systems in a more cost-effective and efficient manner. For example, O&R is collaborating with storage vendors and local authorities having jurisdiction ("AHJ") to site the storage assets in optimal locations. In addition, O&R is working with these vendors so that the batteries have the ability to meet the distribution system need, while providing adequate levels of visibility and control to O&R's distribution system operators, thereby enhancing the safety and reliability of the power system.

    When deploying storage technologies, it is important to consider the applications for which the systems are intended. For instance, short- and medium-duration applications such as peak shaving, demand charge management, and distribution system upgrade deferral traditionally have been served by Li-ion batteries due to their low cost. However, Li-ion batteries may not be as well-suited for long-duration applications such as providing reserve capacity. Rather, long-duration assets such as flow batteries or even pumped hydro-electric storage may provide more cost-effective solutions. Finally, residential solar plus storage systems can provide resiliency benefits and EDCs may be able to operate those assets in aggregate as a virtual power plant to provide system benefits and grid services that benefit a broad customer base.

Through research and development efforts, the Company is also exploring the safety, performance, and operation of a variety of energy storage technologies, including emerging electrochemical based storage (e.g., zinc-based chemistries, lithium batteries with safer electrolyte alternatives); electromechanical systems such as flywheels; and thermal storage.

15. POWED - Currently, battery storage is the most economical on a $/kWh basis. Lithium Ion is the most dominant technology due to its reliability, performance and bankability.

16. SUN - Battery Storage - Sunrun offers a solar-plus-storage service ("BrightBox") in several jurisdictions such as Arizona, California, Hawaii, Massachusetts, New York, Florida and Puerto Rico. Our Brightbox battery paired with solar, a smart inverter, and load management capabilities typically utilizes a DC-coupled system for 100% solar charging of the battery, with connectivity through Wi-Fi or cellular for remote asset monitoring and dispatch.

    The resiliency that residential solar plus battery storage provides does not only inure to the benefit of the individual consumer. Sunrun believes that customers – and how they manage their energy consumption where they live and work – are the grid's greatest energy resource. For customers, there is truly power in numbers. Aggregated, customer-sited storage paired with solar can provide tremendous benefits to customers, the electric distribution system and the wholesale marketplace. In February of this year, ISO New England held its Forward Capacity Auction for the 2022-2023 period. ISO – NE is comprised of six New England states (Maine, Vermont, New Hampshire, Massachusetts, Rhode Island, and Connecticut). Sunrun submitted a bid to provide 20 megawatts of residential solar and battery to the ISO NE capacity market, bidding in to fill the same need that fossil-fueled peaker plant would. Sunrun won the bid, marking the first time that customer-sited solar and battery systems will have been selected to participate in any wholesale forward capacity market in the United States. By having been selected, Sunrun will provide demand response services and the batteries will cycle as needed during windows in summer (June/July/August) and winter (December/January). Sunrun's solar plus storage systems will be able to provide these grid services while maintaining back-up power for each individual customer's home. Local solar and batteries can benefit all grid participants.

19. SUNOWNER - Lithium technologies are the primary storage in use today for up to four or six hour discharge periods, and the cost of this technology is continuing to decline. Flow batteries are generally more cost effective for longer discharge periods but production has not reached significant scale.

Item 4. What might be the benefits and costs to ratepayers, local governments, and electric public utilities associated with the development and implementation of additional energy storage technologies?

1. PSEG - There are a number of potential applications for energy storage which can be incorporated into utility operations and should be explored. For instance, as described in PSE&G's CEF-EVES filing, use cases involving solar smoothing, distribution investment deferral, community microgrids, outage management, and peak load reduction for public sector facilities would be useful to customers in the future. Ultimately, as these technologies continue to evolve, it will be critical that both the BPU and the EDCs have a core understanding of the potential benefits and system challenges associated with energy storage integration. The costs associated with implementation would include the cost of the energy storage, financing charges, and the expenses to maintain the energy storage system. Depending on where and how the storage is deployed, ancillary costs like site preparation, permitting, warranties, refurbishment, site rent, etc. will also need to be considered when implementing an energy storage system.

2. CEG - See MA State of Charge report, also see upcoming CEG report on storage in EE plans. Cost benefit analysis in both reports shows storage to be cost effective.

3. DER - For ratepayers that invest in energy storage systems, the most obvious cost is the upfront costs associated with such investment. As stated earlier, in order to incent widescale adoption and investment in these technologies, the market and regulatory constructs must exist to provide reasonable economic payback on the investment. Identifying the grid services or benefits that can be provided by energy storage technologies, is the first step in determining what markets or regulatory constructs are needed to value and compensate for those services. In the case of energy storage paired with renewable generation, the right price signals may allow for such systems to be used for peak shaving, reducing electricity costs to ratepayers. Such systems could also conceivably be aggregated and used by System Operators to balance supply and demand on the grid. There could be resilience benefits of having these systems as part of a microgrid, or as back-up generation in the case of an outage or disruption in service.

   The key to realizing the full potential of electric storage systems is to create the market and regulatory mechanisms to identify, value and compensate for the services that these technologies provide.

   The other aspect that should not be neglected is that whatever regulatory construct is adopted should minimize or eliminate any cost shifts that may occur from ratepayers who own energy storage systems to those who do not. This is where it is important that utilities and the BPU work closely to ensure appropriate rate designs that incents innovation and choice, while also allowing the costs of maintaining a reliable, resilient grid, to be fairly allocated to all ratepayers.

Another costs to be considered is that associated with research and development into newer, more efficient and cost-effective technologies. One central question is who should bear the cost of research and development in this area. If energy storage is seen as a vital part of a sustainable, reliable and resilient energy future, what is the role for government, utilities, and the private sector in facilitating research and development in this area? Is this an arena where public-private partnerships make sense in order to further innovation.

4. NJDRC - See Rate Counsel response to item 1.

5. OCE - Again, difficult to generalize the benefit-cost analysis from other states to New Jersey. It is important to keep in mind that there are some hard-to-quantify benefits, such as the potential for reduced local air pollutants, that shouldn't be completely disregarded. Storage can provide a range of resilience benefits as well - for the site host (e.g. a residence with BTM storage that is primarily providing services to the grid but is available when the grid goes down), for a group of customers (e.g. on a circuit with a storage device that can provide backup to a larger number of customers) or for customers as a whole (e.g. storage located at a critical facility).

   Storage allows customers to charge off peak thereby saving money, lowering environmental emissions, and avoiding the need to draw power during peak periods. This flexible load makes a utility's system more flexible and capable of accommodating greater amounts of renewable energy.

6. VES - Energy storage technologies provide numerous benefits to the grid as well as help support the expansion of clean energy sources. As noted above, grid benefits range from reduced peak loads, energy cost savings, reduced demand charges, and other ancillary services as well as the associated revenue streams that are created when more storage is deployed as well as savings for taxpayers as storage negates the need to build new peaker plants and transmission infrastructure.

   Additionally, we would also like to underscore that storage, when combined with solar and other clean technologies, enables resilient communities especially when these systems are placed on critical facilities such as police stations, fire stations, hospitals, communications centers etc. These critical facilities can not only fulfil their mission leading to quick recovery during a disaster but also shelter and provide support for families, avoiding expensive evacuations.

   Moreover, storage on multi-family housing can greatly aid in ensuring the residents of these buildings, especially those that are more vulnerable such as elderly and low-income, continue to receive basic services such as power, functioning elevators etc. during disasters.

   While we recognize that new storage deployment will have a cost impact on ratepayers, the cost of inaction on climate change is far greater. Through numerous reports such as the National Climate Assessment and the Intergovernmental Panel on Climate Change, the scientific community has warned us about the increase in frequency of climate related events that will cost millions of dollars in economic damage and recovery. As natural disasters increase, vulnerable communities will become even more vulnerable. Shoring them up with resilient solar plus storage solutions will help to ensure community safety during and after events, and can help to speed up recovery. We owe it to underserved communities to invest in this type of clean and affordable solution. The cost of not doing so would be less safe, more vulnerable, and worse off communities which will have tremendous impacts on the well-being of the state of New Jersey.

7. OMNES - Currently, the only technology being promoted is Li-ion battery technology, which is prone to a host of problems as mentioned above. It is important to support other technologies so that NJ ratepayers can have a choice in energy storage methods.

8. INGER - TES provides commercial and industrial customers with the ability to materially time shift their energy usage during hot summer months. It relies on chillers that make ice typically at night (charging) which is then used to provide air conditioning service during the day (discharging).4 This process enables building owners to use off-peak energy during peak times. TES is also highly durable and efficient. CALMAC TES tanks have a useful life as long as 30 years with little maintenance cost and achieves round trip efficiencies approaching 97%.5 Moreover, it can provide cooling service for at least eight hours at a time, and almost all of its components can be recycled at the end of its useful life. Overall, TES lasts 2 to 4 times longer than batteries at a fraction of the cost.[6]

   The deployment of TES can help New Jersey achieve its clean energy goals. TES is well suited to "storing" the wind energy it uses at night for daytime use.7 This enables emission-free energy to be utilized during the day and reduces the need for peaking fossil fuel plants.

9. JCPL - As detailed in its response to Question 1 above, JCP&L believes the further deployment of energy storage technology has the potential to benefit both the EDCs' systems and their customers. The key to maximizing this benefit for the EDCs' customers is the strategic integration of energy storage technologies. The EDCs are in the best position to identify areas where such deployments can provide the most benefit to their customers at the least cost. While the specific benefits realized by ratepayers, local governments, and EDCs vary somewhat depending on their needs, all will benefit from allowing the EDCs to play a primary role in maximizing the value-proposition provided by the deployment of energy storage technology.

10. NJCF - This question assumes that storage investments will be made by regulated electric public utilities and local governments, with costs passed on to ratepayers and, presumably, taxpayers. Some storage applications may indeed be procured and financed this way. Under the planning approaches recommended above, which focus on finding the most cost-effective solutions to system balancing needs and, among those solutions, the least-cost utility owned or purchased storage solutions that create the biggest stack of benefits, any such ratepayer costs should generally be lower than the costs to ratepayers would be of achieving comparable levels of clean energy deployment and global

warming response without the storage. However, many storage applications could readily be invested in privately, with the capital costs incurred by private investors, not regulated utilities, and with recovery of those costs based on providing competitive storage services (to the wholesale market and to end-use customers, not as part of utility rates) that make the customers better off than if they did not buy them. Additional benefits could be achieved by substituting such storage solutions for more expensive “wires-only” distribution solutions, which would also make ratepayers better off. For all these reasons, NJCF recommends the BPU consider focusing on competitively provided storage solutions wherever possible.

11. NJR - The transformative potential for storage was discussed in question 1. State incentives will be necessary to encourage storage development for the foreseeable future. Total costs can be determined after program targets and incentive levels are determined.

12. MSS - The benefits to ratepayers, local governments, and utilities are discussed elsewhere in this response.

13. SP - As discussed above, energy storage systems offer benefits to the grid – and so to ratepayers, local governments, and utilities – the form of very fast dispatch and operational flexibility. Programmatic investments made in energy storage systems have the potential to offset investments in higher-cost, more GHG-intensive traditional generation resources and grid infrastructure. We encourage program designers to develop evaluation frameworks in which energy storage resources can be compared to traditional grid resources on an “apples-to-apples” basis with traditional resources, including specific performance requirements (e.g., historical dispatch events, duration, and timing) and project life-cycles.

14. RECO - As previously discussed, energy storage has the potential to provide a wide range of benefits to a variety of stakeholders including EDCs and customers. When analyzing the benefits and costs of an energy storage system, it is important to consider the full range of benefits that energy storage can provide. It is also necessary to prioritize those deployments that provide the most net benefits to both the energy grid and all customers to offset the still relatively high cost of energy storage deployment.

    Benefits of energy storage can include avoidance of capacity obligation and generation capacity infrastructure costs, avoidance of line losses, distribution and transmission infrastructure upgrade deferrals, energy consumption savings, and others. Intangible benefits such as increased resiliency and increased operational flexibility, while currently difficult to monetize, may also be considered in the analysis of energy storage projects. With the appropriate changes for energy storage participation in wholesale markets, energy storage resources may have the potential to earn revenues in capacity, energy and ancillary services markets, such as frequency regulation and spinning reserve.

    It is important to provide for various ownership models, including both EDC and third-party, to realize the benefits of energy storage deployment. EDC ownership and operation of energy storage systems may unlock the ability to realize a broader range of storage benefits for all customers due to the EDC's knowledge and operation of the distribution system, paired with the understanding of the electric grid's needs and insight into the integration of the storage asset with the grid.

Costs of additional storage would include the cost of potential distribution and transmission system upgrades, any incentives that would be provided to the storage developers, the socialization of any incentive-based rate design, and the costs of compensation for the energy dispatched. As previously stated, these costs must be considered along with the benefits provided to assess the storage system's cost-effectiveness and efficiency.

15. TESLA - The goals set forth in New Jersey's Clean Energy Act of 600 MW by 2021 and 2,000MW by 2030 are appropriately ambitious and achievable. 600 MW is equivalent to ~3% of NJ's peak load which is consistent with other regional targets. The New York State Public Service Commission recently issued an order establishing energy storage goals of 1,500 MW by 2025 and between 2,600 to 3,600 MW by 2030 with deployment mechanisms to achieve both the 2025 and 2030 targets. Among other things, the NY PSC Order focused on:

    • Authorizing an energy storage bridge incentive program to include funding for solar-plus-storage projects participating in their NY-SUN solar incentive program,
    • Directing the State's six investor owned utilities to hold competitive procurements for a minimum of 350 MW of bulk-sites energy storage, and
    • Continued efforts to streamline permitting, interconnection, and siting challenges and ensuring straightforward access to market rules and opportunities.[1]

    For New Jersey, Tesla recommends two primary policies support the deployment of energy storage systems:
    1. Energy storage procurement targets; and
    2. Customer-located energy storage incentive programs.

    Storage procurement targets have been one of the primary drivers of storage procurement to date, largely because traditional utility planning, valuation, and procurement processes do not account for the unique attributes of energy storage. Storage procurement targets are set as an amount of installed energy storage capacity that can be measured as a percentage of peak load, in megawatts (MW), or in megawatt-hours (MWh). Generally, however, some consideration of both the power (MW) and energy (MWh) is appropriate given that both attributes factor into the value of the energy storage systems to the grid. Storage procurement targets should require deployment of some storage at every point of interconnection to the grid – transmission, distribution, and customer-located – to ensure sufficient learning with different applications of storage. The details surrounding what types of energy storage should be procured can be left relatively open-ended to allow (and require) the utilities to do the appropriate analysis to understand where energy storage can be most valuable to their unique grids.

Storage targets force learning by doing. For example, when Southern California Edison was given a 50 MW storage target in a 2014 solicitation for new generation capacity, it ended up procuring 264 MW of energy storage – 5 times what was required – because, to its surprise, it found that storage was a cost-effective alternative.2 Further, gaining experience deploying energy storage provides optionality to states in emergency situations where they may need to deploy resources more quickly than traditionally occurs. For example, after a natural gas system leak threatened the electricity reliability of the Los Angeles Basin, the utilities were able to bring over 100 MW of storage projects online in less than a year.[3]

New Jersey should develop a new incentive program in the form of rebates for customer-located energy storage. Customer-located energy storage can provide all of the benefits of utility-scale storage plus it provides direct customer savings and increased resiliency in the form of back-up power. The NJ BPU's Renewable Electric Storage program, with $6M for projects in 2016, was a start but was not sufficiently funded or designed to launch a robust energy storage market. The most established model for energy storage incentives to date is California's Self-Generation Incentive Program, which provides an incentive of ~$0.40 per watt-hour of installed energy storage capacity for systems located at residential, commercial, or industrial sites. Accordingly, California makes up over 90% of the customer energy storage deployments in the US. In New York State, NYSERDA is providing a $0.35/Wh energy storage incentive eligible to small and large commercial businesses, industrial customers, and community solar project developers.

16. POWED - Energy storage has a net reduction of cost to the rate payers and strong payback/benefit-cost ratio. Please see attached analysis.

17. SUN - There are significant benefits of storage to all classes of ratepayers which we anticipate will be reviewed as part of the NJBPU's Energy Storage study. Please refer to the response to question #1.

18. SUNOWNER - Most of NJ's peaking generators are simple cycle, old and highly polluting when they operate. Solar and wind generation, whether co-located or located remotely, will operate to reduce carbon emissions, stabilize the grid, and reduce air pollution, especially in the area around existing fossil fuel peaking generators. These peakers are more often located near lower economic areas and adversely impact air quality for nearby residents. As storage costs continue to decline they will become cheaper than continuing to rely on the existing fossil peakers, and allow them to retire.

Item 5. What might be the optimal amount of energy storage to be added in New Jersey over the next five years in order to provide the maximum benefit to ratepayers?

1. PSEG – Aside from the Clean Energy Act's goal of 600 MW of energy storage by January 1, 2021, use cases for storage should be conducted by the industry prior to determining the "optimal amount of energy storage" that should be constructed over the next five years. Many of the energy storage use cases that could be incorporated into utility operations, such as distribution deferral, have not yet been implemented by the New Jersey EDCs. The EDCs should initially pursue targeted deployments to see which applications bring the most value to New Jersey customers before setting broader targets. In implementing targeted deployments, EDCs will learn the most efficient and effective ways that storage can be applied to the existing distribution system.

2. CEG - This will require a study to determine.

3. As noted in the Introduction, the Board approved a contract with Rutgers University to perform an analysis of the state's energy storage needs and opportunity. The report is expected to discuss and quantify the potential benefits and costs associated with increasing energy storage and DER. Thus, Rate Counsel finds this question to be premature, and recommends that the Board wait for Rutgers to present the results of its study.

4. OCE - This is a tricky modeling question. Hard to optimize any energy resource without looking holistically at how the system operates and what the needs are.

5. VES - We appreciate the 2000 MW by 2030 goal that is created under the Clean Energy Act but a goal without clear pathways to ensure all New Jerseyans benefit is a missed opportunity. We recommend that 20% of all storage deployed by 2030 serve low-income, environmental justice, and communities of color which translates to 200 MW of storage by 2025 and 400 MW by 2030.

6. OMNES - 100 MW of 4 hours duration would be the minimum energy storage to be added.

7. JCPL - As discussed above, the key to maximizing the benefits of energy storage technology is the strategic integration of it into the EDCs' transmission and distribution systems. Accordingly, the optimal amount of energy storage to be added in New Jersey is dependent on the unique needs of each EDC. Detailed studies would need to be performed by each of the EDCs to definitively determine the optimal amount of energy storage to be integrated into their individual systems.

8. NJCF - The right amount of storage for New Jersey, as well as the type and key physical and operational characteristics needed, can only be even approximately understood by a relatively detailed, regional dispatch simulation analysis that explores optimal paths for

New Jersey's clean energy deployment over the next decade, along with reasonable assumption for parallel clean energy deployment throughout and interconnected into PJM. Such analyses should be a major focus for current energy planning at the BPU and for the evolving energy master plan.

9. NJR - Until storage markets can function without incentives, the optimal amount of storage will need to be determined by policy, reflecting on the Clean Energy Act targets of 600 MW by 2021 and 2 GW by 2030. These policies must also consider the funding necessary to support storage incentives. In the absence of these incentives and program drivers, storage installations will be limited. The cost involved to incent stationary storage in New Jersey should be weighed against other alternatives that also provide or enhance flexibility and resiliency to the grid. These include fast response generation, additional energy exports, curtailment of renewables or load, peer-to-peer energy transactions or electric vehicles.

10. MSS - MSSIA believes that thorough study is required in order to have a reliable assessment of the need for storage over the next five years. However, MSSIA generally agrees with the amounts required in the Clean Energy Act. Linear interpolation between the 600 MW by 2021 requirement and the 2,000 MW by 2030 requirement leads to an amount of energy storage in five years (2024) of about 1,170 MW. Assuming that the average discharge time duration of the energy storage is 2.5 hours (a guess), that would translate to about 2,900 MWH in terms of the energy rating of the storage (see below under Question 11 for more explanation of power rating vs. energy rating).

11. SP - We believe the State goal of 600 MW of energy storage by 2021 in year is an ambitious and achievable goal that will drive storage project deployments at speed and scale, progressively reducing development costs to the benefit of ratepayers. By contrast, the goal of 2,000 MW by 2030 would equate to a slowing of deployments on an annualized basis relative to the 2021 goal (~133 MW/year), which would create incentive for storage project developers to focus on deployments in NJ after 2021, reducing competition and raising cost to ratepayers on a per-MW unit basis. For that reason, we believe the 2,000 MW goal should be pulled in to 2025, accelerating the rate of deployment and reducing ratepayer cost.

12. RECO - Determining the optimal amount of storage that can be added to the electric distribution and transmission systems requires detailed studies to establish the ideal amount of energy storage that can be added in order to maximize the benefits to customers. This in turn must be weighed against the costs of any upgrades to the transmission and distribution system to accommodate the increased amount of energy storage.
    One way to determine the optimal amount of energy storage is to "test the waters" with projects that test a specific, defined hypothesis designed to help EDCs and the Board understand customers' needs, evaluate novel business models, develop effective ways to implement storage, learn valuable lessons, and support the progress towards reaching the State's Clean Energy Act goals. These test projects would be run by the EDC, in

partnership with third parties, to test the capabilities of various technologies, as well as new approaches to assessing the value provided by such technologies, all while working within unique and novel business models. Lessons learned from these projects can be used to inform future State policies and regulations. Projects like these, that are ratepayer funded, will evolve into the development of long-term models and strategies that benefit all customers.

In addition, appropriate rate design can encourage the deployment of energy storage that provides benefits to the electricity grid while balancing the costs borne by all customers. Such rate design can be used in conjunction with test projects or implemented separately to apply to all storage systems.

The Company is anticipating continued growth in energy storage deployment on its electric transmission and distribution systems driven by the State's energy storage goals, potential changes in wholesale market rules, and the addition of community solar. Support for increased energy storage deployment can be found in the implementation of alternative solutions to an EDC's traditional infrastructure upgrades/expansion. Moreover, partnerships between EDCs and third parties may allow for the deferral of traditional infrastructure upgrades/expansion while also providing additional benefits from technologies, such as storage.

13. TESLA – Please see below representative real-world examples of energy storage and distributed energy resources providing resilient electric service at different points in the electric system. Please find associated one-page descriptions of these projects in the Appendix:

    South Australia Powerpack Battery System
    Energy storage can be quickly deployed in order to provide services that can stabilize the bulk power system and prevent a bulk power system outage. In September 2016, a 50-year storm damaged critical infrastructure in the state of South Australia, causing a state-wide blackout that left 1.7 million residents without electricity. Further blackouts occurred in the heat of the Australian summer in early 2017. In response, the South Australian Government sought to deploy grid-scale energy storage to ensure energy security for its residents. Tesla was selected through a competitive bidding process, and on December 1, 2017, Tesla commissioned a 100 MW / 129 MWh Powerpack battery system at Neoen's Hornsdale Wind Farm near Jamestown, Australia. The battery system participates in Australia's National Energy Market, providing energy arbitrage; reserve energy capacity, as contracted by the South Australian government; frequency control ancillary services; and network loading control ancillary services, which detects high flows on a major interconnecting transmission line and triggers the 100 MW to start discharging as quickly as possible to prevent the South Australia power system from separating from the rest of the national energy market. The Australian Energy Market Operator ("AEMO") recently released a report4 detailing the initial operation of the battery system, pointing out that data demonstrates that the regulation Frequency Control Ancillary Services provided by the system is "both rapid and precise, compared to the

service typically provided by a conventional synchronous generation unit." The report highlights the battery system's rapid response to a frequency deviation caused by the trip of 689 MW of coal generation in New South Wales on December 18, 2017.

Southern California Edison (SCE) Storage Peaker Plant
In response to the Aliso Canyon natural gas storage facility leak and the associated potential for grid outages, Southern California Edison undertook an accelerated procurement for utility-scale storage solutions that could be operational by December 31, 2016. Through a competitive bidding process, Tesla was selected to provide a 20 MW / 80 MWh Powerpack system at Southern California Edison's Mira Loma substation. Tesla successfully installed the system in only three months, far quicker than traditional generation can be developed, even in emergency situations.

Southern California Edison owns and operates the Powerpack system, which offsets four hours of peak electricity demand thus reducing the need to rely on the region's now-fragile natural gas infrastructure during peak times. The Powerpack storage system also provides ancillary services, procured through competitive wholesale markets, to support reliability in the region. By taking advantage of the multiple value streams that energy storage systems provide, projects like the Southern California Edison's Mira Loma battery project can be cost-competitive with conventional generation.

Residential Customer-Sited Solar Plus Storage
Numerous Tesla Powerwall customers in Florida were able to maintain power at their homes throughout the grid outages that occurred during Hurricane Irma.5 Customer-sited solar and storage, which Tesla is installing throughout in New Jersey and throughout the world at individual customers' homes, also offer customers resiliency in the form of back-up power when the grid is down. When there's a grid outage, Tesla's Powerwall battery systems paired with solar systems immediately react to safely maintain power at customers' homes so that they can operate important loads indefinitely, as the solar panels recharge the batteries daily.

Puerto Rico Microgrid and Customer-Sited Storage
Similar solar and storage microgrids can be installed at critical facilities, such as hospitals and community centers, to provide resilient electric infrastructure. Microgrids that rely on renewable energy sources and energy storage units support continued operations even when there is extreme damage to transmission, distribution, and central-station generation, as occurred recently in Puerto Rico due to Hurricane Maria. In response to the devastation to Puerto Rico's bulk electric power system due to Hurricane Maria, Tesla deployed over 600 battery systems at sites across the island to provide power. In Montones, Puerto Rico, Tesla's microgrid is providing power to a remote community, where the grid had not been restored for many months.

14. POWED - 1GW. Current target of 600MW by 2021 only addresses system peak reduction. Additional storage will be needed beyond 2000MW by 2030 for renewable management and firming.

15. SUN - We recommend that the inquiry be framed differently to address the specific issues and problems in NJ's energy delivery system that need solutions in the next five years and beyond. Specifically, we would encourage the study of pain points throughout NJ's grid and ratepayer experience that need improvement – whether it be the need for: 1) energy savings and cost reductions for consumers; 2) increased resiliency with greater impacts of climate change; 3) and/or cleaner peak. Energy storage is not the end goal, in and of itself, but an effective vehicle through which NJ can effectively improves conditions in the grid and empowers consumers to have greater control of their energy expenses. The energy storage targets – and related studies and stakeholder input – established by legislation in Massachusetts (1,000 MWh by 2035) and New York (3 GW by 2030; New York State Energy Storage Roadmap) can inform the process in NJ.

16. SUNOWNER - NY has goals of 1500MW of storage by 2025 and 3000 by 2030. I expect those goals to be increased as storage costs decline . The NJ grid has about half the demand of NY so 600-800MW would be a good initial target by 2025. The most cost effective storage could be to do a solicitation among the existing solar systems to secure near term storage capacity. With over 500MW of grid supply interconnected, the interconnection cost should be relatively low and average system large. FERC 845 would appear to allow approval of the storage plus the existing solar at the rating of the solar alone (i.e.,10MW of solar plus 10 MW of storage would be rated as a 10 MW interconnection). Residential and commercial storage should also be encouraged, as NY is doing with $350/KW for systems with at least 4 hour discharge capability.

Item 6. What might be the optimum points of entry into the electric distribution system for distributed energy resources (DER)?

1. PSEG - Distributed energy resources (DER) could be integrated within a substation, along a circuit, near large existing and future solar sites, or behind a customer’s meter. The specific use case for the energy storage application will determine the optimal point of interconnection. For example, if storage is being deployed by an EDC to address an overloaded circuit in a residential area, then the energy storage system may need to be deployed at the local substation due to siting challenges along the circuit. Conversely, if an energy storage device being deployed by an EDC is intended to address voltage issues due to intermittent solar energy, then the device may be most effective if deployed close to the interconnected solar array.

2. CEG - This would require a very granular study. MA did something like this in the State of Charge report, but at quite high cost. An alternate and less costly option is to get this information from the utilities. Or the state can require utility procurement with a minimum requirement for DER and limits to utility ownership (as CA did with its storage procurement mandate) and let the utilities figure out where to incentivize DER.

3. NJDRC - This question is best answered through a cooperative effort involving the State's electric distribution companies ("EDCs") as they would hold the most valuable information as to what would be the optimum points of entry into the electric distribution system. EDCs and DER project developers should work together with Board Staff and other stakeholders to identify areas of constraint as well as areas where capacity and/or resiliency may be needed and may provide the highest value. As an example of this approach, in California the three largest utilities have provided online interconnection maps. The maps are intended to show developers key information about the interconnection potential for solar, as well as electric vehicles and battery storage.[2] Maps include general locations of distribution circuits, substations, sub-transmission systems, and areas of transmission constraints along with associated voltage, available capacity and current and queued DG interconnections amounts. Similarly, Pennsylvania's largest electric and natural gas utility, PECO, offers a "DER Interconnection Viability" map to help customers and developers determine the preliminary feasibility of installing DER at a certain location.[3] And in Hawaii, the utilities have shared Locational Value Maps with the goal of integrating "as much consumer-sited renewable generation as possible while maintaining reliable service to all customers. "[4]

4. OMNES - A first step would be the use of energy storage installations for ancillary services such as frequency regulation (FR) since New Jersey is within the PJM grid, which has a long-running program to pay for private operators who plug into their grid to perform FR.

The second mode for using energy storage, which will provide immediate benefits to the existing utility structure is to use them for demand charge reduction and time-of-use (TOU) load shifting.

5. JCPL - In JCP&L's experience, the optimal points of entry for DERs onto its system are along main-line infrastructure (consisting of three-phase, heavy-gauge wire). DER installations in these areas have reduced connection costs because less reconfiguration of the Company's facilities is required to allow for the DER's injection of additional electricity onto the grid.

6. NJCF - There are two common paradigms for thinking about where DERs (including batteries) are best located on the distribution system. The first is where they create the most "stacked value" for their hosts (i.e., end customers), the distribution system and the grid. The second is where the distribution system can best accommodate them. This latter is sometimes called "hosting capacity analysis". Both these approaches can be used to target initial DER investment, but unfortunately, they both tend to miss the critically important question of what is needed for the DERs to actually operate and help integrate large volumes of VRE.

   Instead of simply looking at hosting capacity or value, it can also be important to work through such operational requirements in identifying early DER deployment opportunities. For example, some types of DERs simply shift load in time, which can dramatically help with VRE integration, stay well within the existing distribution system's operating parameters, and require little other than the ability to observe the price signal from the wholesale market, rather than actively participate in it. Smart thermostats and several other distributed services can operate in this mode. Batteries could, as well. Further, batteries could potentially also use their digital inverters to provide some degree of voltage control for the distribution system. This suggests a possible low cost, incremental pathway for DER and battery deployment on the distribution system, without attempting to simultaneously make massive investments in things like automated metering infrastructure (AMI), entirely new regulatory and utility business models, and other resource and time-intensive changes.

   Other types of DERs can have major interactions with the distribution system, including reversing flows on feeder lines, that would require more complex and significant system monitoring, analysis and control technologies to support, as well as potentially much more systematic reengineering of the distribution system and its current distribution management systems, and potentially of the regulated utility business model itself. This is why a significant effort in distribution system planning is needed in New Jersey – to identify low cost, high benefit DER applications, and avoid high cost, low benefit ones. This is especially true for early storage deployment.

7. NJR - The state should prioritize those segments of the market with high strategic relevance, low incentive requirements, ratepayer impacts and low barriers to entry. Based

on the analysis of New Jersey Resources (NJR), the most promising segments for storage today include:

- Behind-the-meter commercial sites with predictable peak loads (for example hotels and hospitals), which can use storage to reduce monthly demand and allocated generation charges. Supplemental benefits may include demand response revenues and energy arbitrage in response to time-of-use rates. If paired with new solar to provide resiliency, storage projects are eligible for a 30 percent ITC (at declining rates after 2020), which can reduce the need for state incentives.

- Utilities can leverage storage as a "non-wires" alternative to defray the cost of transmission and distribution upgrades. Storage, when deployed to reduce congested or closed circuits constraining solar development, can be important in contributing to the state's clean energy goals. Utilities can effectively direct storage resources to locations with have the greatest need, and leverage storage for supplemental revenue streams. A mix of utility and third-party-owned storage models should be considered to support utility needs.

In contrast, wholesale market economics for storage resources in PJM are more challenging:

- The daily spreads between on-peak and off-peak locational marginal prices (LMPs) are insufficient to support project economics on a standalone basis. Increased wholesale price volatility is possible with greater penetration of intermittent renewables; however, this is not likely to be the case in New Jersey until the 3,500 MW of offshore wind is installed.

- While storage could be a viable long-term alternative to meet system peak-capacity needs, in PJM, capacity market prices are well below the levels needed to support projects at today's costs - even with cost declines expected over the next several years. PJM's revised capacity market rules are also less favorable for batteries, requiring 10 hours of storage capacity to participate. This is beyond the economically-feasible range of four hours for storage projects today. Most storage projects could still participate in the market; however, capacity payments would be de-rated.

- The PJM frequency regulation market has supported storage project development to date. According to EIA, there were nearly 300 MW of batteries providing regulation service to PJM in 2018. According to the PJM interconnection queue, there are over 1.3 GW of solar plus storage projects that have applied for interconnection in New Jersey, reflecting developers' desire to take advantage of the 30 percent ITC available for storage systems paired with solar.

It is questionable if much of this will be built given the oversupply in the regulation market, depressed prices, market risks and the limited potential for supplemental revenues from energy and capacity markets. While issues over local grid stability are possible with increased penetration of intermittent renewables, this does not necessarily translate to the need for more regulation services. The regulation market does not require additional state incentives to support activity, nor is the need to stabilize PJM's grid frequency strategic for New Jersey.

The retail residential market poses its own economic challenges for several reasons:

- As a resiliency resource, solar paired with storage is more expensive and less reliable than other forms of backup generation.

- The spread between off-peak and on-peak time-of-use rates provides little incentive for load shifting under current time-of-use tariffs in the state. Price differentials need to be greater, with shorter peak time periods, to be a better match with battery costs and performance capabilities.

- Current net metering policy, which has been essential to supporting the growth of behind-the-meter solar, does not facilitate the need for storage. Any changes to net metering policy need to be comprehensively considered in context of clean energy goals, approaches to better value solar generation and the impact of new technologies including storage.

The Federal Energy Regulatory Commission's (FERC) recent Order 841 may create new opportunities for retail storage to participate in wholesale markets. Despite the challenges with these markets, the state may want to encourage the participation of residential storage systems to demonstrate the potential for DER markets. It might be necessary for utilities to play an intermediary role between retail participants and wholesale markets.

8. MSS - Generally all points of entry to the distribution system for DERs are useful. They can reduce peak loads on the circuits and substations to which they are connected and help control voltage. Energy storage in particular can provide those services, and also help counteract any effects of intermittency from renewable DERs.

   In particular, points on the distribution system that are experiencing congestion or voltage excursions are especially optimal places for connecting DERs. Points on the distribution system that have high solar energy penetration are especially optimal places to connect energy storage. "End-of-the-line" battery assets can be aggregated to be particularly useful during peak demand periods, in addition to performing many grid-stabilizing services during normal times.

   As mentioned before, critical facilities are valuable places to connect all types of DERs, singly or in combination as microgrids, that are capable of providing emergency backup power.

Any locations that have, or are likely to have, especially large total amounts of solar power connected, or that have single large-scale solar farms connected, should be prioritized for energy storage.

Finally, once large amounts of offshore wind power come online, it will be important to locate as much energy storage as possible close to the point of interconnection of that wind power as it reaches land. However, note that the offshore wind connection point or points may not be on the distribution system.

9. SP - Certain points of interconnection with the electric distribution offer specific advantages, such as co-location with intermittent renewable resources to smooth generation and take advantage of tax benefits to reduce ratepayer cost, or location within load pockets with acute energy import congestion during specific timeframes that could be lessened with load-shaving storage. We encourage program designers to investigate specific areas of the distribution system to determine locations where storage might offer the most value through the supporting the local grid via NWA projects. Program designers might also choose to allocate a greater share of funding to areas where ratepayers bear a greater-than-average cost of service from both generation and delivery.

10. RECO - A key to unlocking the potential of energy storage is to locate systems where the maximized revenue streams of the investment (e.g., distribution capital investment deferral; aggregation or wholesale opportunities; and peak shaving / reduction for both customers and EDCs) may be realized. Therefore, the optimum point of entry of DER into the distribution system will vary depending on the use case being deployed. For example, to realize distribution system benefits, DER may be most useful when interconnected as close as possible to the load being relieved. This approach reduces system electrical losses and allows the greatest flexibility in capturing multiple benefit streams. By locating a DER source close to the distribution load, load reduction on the distribution circuit can relieve equipment constraints and/or provide contingency relief.

11. POWED - DER's can be optimally connected at the distribution level. However, transmission and bulk generation level connections are also applicable.

12. SUN - As noted above, behind-the-meter battery storage systems can provide the greatest value to ratepayers, the utility and the larger grid. Residential, behind-the-meter batteries are being deployed faster than other market segments. In fact, the Smart Electric Power Alliance reported that from 2016 to 2017, residential capacity additions grew by 202% in terms of MW, while non-residential additions grew by a modest 9%.1 Residential systems utilize the pre-existing built environment, avoiding land use and siting issues. Solar consumer demand for battery storage systems is also high and growing.

13. SUNOWNER - Points of entry should be both in front of the meter and behind the meter. Sonnen recently won capacity from the New England ISO for 20MW of storage to come from 5000 residential storage units. Storage can also be combined with solar and targeted

demand reduction to provide Non-wires Alternatives for nearly all utility proposed grid infrastructure expansions. To address our carbon reduction goals NJ should not permit any natural gas supply or generation because renewables, efficiency and storage can provide more cost effective solutions than fossil based proposals. Substation capacity has already been augmented with storage in other states instead of expanding electric high voltage transmission for the relatively few hours it was estimated to be needed.

Item 7. What might be the calculated cost to New Jersey's ratepayers of adding the optimal amount of energy storage?

1. PSEG – Energy storage has the potential to be an important component of utility operations moving forward, and PSE&G looks forward to working with Rutgers and the BPU to address this issue and to explore optimal use cases for energy storage through the implementation of PSE&G's CEF-EVES program. After this and other initial programs are assessed, the State can determine which specific applications for energy storage are the most reliable and cost effective for customers.

2. There are too many variables to answer this, and it would depend on the outcome of a study to determine the optimal amount of energy storage. However, storage costs are declining.

3. NJDRC - See Rate Counsel's response to item 5. Without knowing what the optimal amount of energy storage might be, Rate Counsel is not able to estimate a specific "calculated cost" to ratepayers.

4. OCE - According to Lazard's latest levelized cost of storage, there continue to be significant cost declines across most use cases. There have been sustained cost declines which have exceeded expectations for lithium-ion technologies. Many studies have been done looking at the cost-benefit assessment for various battery storage use cases, and these studies consistently find that energy storage can generate much more value when multiple services can be provided by the battery - which means that market rules and revenue streams need to be in place and accessible. By combining a primary service with a bundle of other services, batteries can provide a net economic benefit to the battery owner or operator.

5. OMNES - Adding 100 MW of 4-hour electrical energy storage is estimated to cost about $200 million, a relatively modest amount considering that New Jersey has over 18,000 MW of electric generator capacity and 3,421 MW of onsite generation.

6. JCPL - As discussed above, the optimal amount of energy storage depends largely on the unique needs of each of the EDCs' transmission and distribution systems. JCP&L projects that the cost of strategically installing energy storage with a capacity totaling approximately 1-2% of the Company's total peak demand would be, at a minimum, in the hundreds of millions of dollars. Additionally, there would be significant costs for the continued maintenance of energy storage technologies after installation.

7. NJCF - Perhaps the greatest reason New Jersey needs to consider storage deployment through an integrated clean energy planning process, with market-based cost and performance inputs, is so it can answer this kind of question before it decides how much and what kind of storage to encourage, rather than after.

8. NJR - As indicated in question 5, until storage markets can function without state incentives, the optimal amount of storage will need to be determined by policy, reflecting on the Clean Energy Act targets of 600 MW by 2021 and 2 GW by 2030. These policies should consider the funding necessary to support storage incentives relative to the competing uses for those funds.

   In California, which is currently a national leader in the installation of energy storage systems, the state defined a total goal of 2 GW of storage by 2020 and established clear procurement megawatt goals for every two-year period through 2020. The state's utilities are responsible for achieving these goals, with a mix of utility-owned projects (capped at 50 percent of total) and procurements from third-party providers. To date, the state is on track to meet or exceed their goals. It will have taken 12 years since the initial passage of California's energy storage legislation to reach the targets, which is consistent with the timeline in New Jersey.

9. MSS - As stated in the answer to Question 4, MSSIA does not believe it can calculate the cost to ratepayers of adding the optimal amount of storage at this time. As stated elsewhere in our answers, careful and comprehensive study that includes many factors, including storage, is needed in order to identify the optimal amount of storage. Further, the cost to ratepayers will be influenced not only by the decline in the cost of the storage technology, but also by the proportion of that cost that can be offset by market revenue, and by the value of parallel additional services, such as emergency backup power, that can be provided by the storage.

10. SP - The answer to this question is contingent upon the specific size of individual storage deployments and the use cases they serve. We look forward to further discussions with program designers regarding ratepayer impact in the context of specific program structures, timeframes, and capacities.

11. RECO - Although the cost of energy storage has declined significantly in recent years, it has not experienced the significant market growth/maturity as other resources (e.g., solar). Therefore, energy storage must be viewed in terms of the benefits it provides relative to the costs. Prioritization must be given to the deployment of energy storage systems that provide the greatest benefit to customers.

    RECO's affiliate, O&R, has experience with non-wire alternative projects to traditional transmission and distribution system expansion project solution(s). In some cases, battery systems may be more expensive than the traditional solution. However, the overall societal benefits provided by energy storage systems may surpass those provided by a traditional solution.

    As a result, a cost-benefit framework is necessary to understand both the costs and benefits of energy storage provided to customers and EDCs. Although storage is not a Class I renewable asset subject to the cost cap on customer bill increases set forth in the

Clean Energy Act, the Board must be cognizant of the cost burden placed on all customers by the deployment of energy storage systems.

12. TESLA - If deployed correctly, adding the optimal amount of energy storage should provide a net benefit to New Jersey ratepayers. The cost of energy storage alone is not a relevant metric since there would also be a cost to the traditional generation, transmission, and distribution resources required if the energy storage was not deployed. Thus, Tesla recommends that the BPU focus on the net present value of storage resources, which is inclusive of both the costs and benefits of the systems.

    A state-commissioned study found that Massachusetts could save $2.3 billion by installing 1,766 MW of storage over the next decade, and recommended 600 MW of near-term storage to save $800 million.[6]

    Analysis performed by Acelerez to support New York State's Energy Storage Roadmap showed that deployment of the 2.8-3.6GW of energy storage by 2030 would result in ratepayer benefits exceeding $3 billion. 7 This analysis examined system needs that can be met by energy storage in a least-cost combination of resources to provide electric system services as the State reaches 50 percent renewable generation and 40 percent greenhouse gas reduction (compared to 1990 levels) by 2030.

13. POWED – See attached analysis.

14. SUNOWNER - Ratepayers will see a net lower long term cost of energy as more renewables are built along with storage and increasing industry scale lowers cost. The growth of DER will lessen the peak loads on the grid and reduce health costs imposed by fossil generated pollution. Electric customers can be induced to share the cost of expanding storage because sufficient incentives will encourage electric customers (some of the existing 100,000 NJ solar customers) to invest the balance to acquire enhanced resilience for their home or business. Smart meters and TOU rates will further encourage more storage to allow solar production to be stored during peak solar production hours for discharge during the hours after daylight hours. See discussion of "The Duck Curve" in California. The need for more solar storage to mitigate the steep ramp up of fossil generation as the sun sets only gets greater as solar capacity continues to grow. The combination of more renewable power combined with storage will produce the lowest long term energy costs for the state as these system costs are amortized because there is no recurring fuel costs. More instate renewables and storage will also recuse the outflow of cash from the state as fewer fossil fuels are imported into NJ for generation of electricity and heating of buildings, and less refined fossil products are imported for transportation.

Item 8. What might be the need for integration of DER into the electric distribution system?

1. PSEG – PSE&G's Clean Energy Future filings proposed a number of DER initiatives that incorporate energy storage systems. The CEF-EVES filing included the Community Microgrid sub-program as well as the Peak Reduction for Municipal Facilities sub-program. The Clean Energy Future - Energy Efficiency filing includes a non-wire alternatives pilot sub-program that envisions deploying distributed storage along with energy efficiency and other methods to address overloads on the distribution system. These programs will allow PSE&G to better understand the role DER could play in the ongoing management of the electric distribution system. While PSE&G does see a number of interesting use cases for DER, the existing generation, transmission, and distribution systems will continue to deliver the most value to customers and be the predominant method of generating and transporting electricity across the grid for the foreseeable future.

2. CEG - Integrating DER into the electric distribution system allows a great deal of flexibility and provides benefits both behind and in front of the meter. See NYS REV proceedings for discussion of storage on the distribution system.

3. NJDRC - See Rate Counsel's response to items 5, 6 and 7.

4. OMNES - DER integration into the distribution system will suppress brown-outs and permit the phase-out of fossil burning generation.

5. JCPL - Meeting the evolving needs and changing expectations of consumers (including their adoption of new technologies) requires a modem electric grid that is intelligent, flexible, and secure. For grid modernization to occur, distribution platform enhancements that include utility smart grid technology are necessary. These upgrades will improve system resiliency and reliability, benefitting customers in the near term, while providing the bridge to implementation of more advanced smart grid technologies and DER. The Board and EDCs can work together to ensure the electric distribution systems are well-equipped to handle the increased integration of DERs into the electric distribution system. This includes appropriate cost recovery mechanisms to encourage and attract investment.

6. NJCF - Instead of primarily focusing on integrating DERs into the electric system, NJCF encourages the BPU and its staff to also think about how to use DERs to help integrate VRE resources into the electric system.

7. NJR - Incorporating DER into the electric distribution system can provide clean, resilient, cost-effective alternatives to new supply. As the penetration of intermittent renewables increases, DER resources can play an important role in balancing supply and demand.

8. MSS - Most DERs will need to be integrated into the electric distribution system. Barriers to this integration is already becoming very problematic, especially in Atlantic City Electric territory, where most of the potential points of connection are either not allowed or highly restricted, and many highly restrictive and expensive policies are applied even when connection is allowed. Many if not most of these problems could be solved by:

   1. Modernizing the New Jersey interconnection standards, which are seriously out of date, and not meant for high penetration of renewables. Up-to-date standards must include high penetration of local circuits, and enabling substations to backfeed renewable power, as is routine in other states.
   2. Allowing smart inverter capabilities to facilitate interconnection approvals (especially volt-VAR control).
   3. Allowing energy storage to provide services to facilitate interconnection approvals.

9. SP - Integration of DERs into the electric distribution system can create benefits for the grid that cannot be realized through the deployment of resources at the transmission level. For instance, the transmission system operator (PJM) is responsible for procuring adequate energy and capacity to serve load aggregated at the zonal level, but it does not have direct control over the distribution system used to deliver that generation and capacity to individual end users. DERs can be used to "fine-tune" generation, capacity, power quality, and other essential grid products at the distribution level, and in doing so defer the cost of traditional distribution grid upgrades and/or additional transmission service to support load pockets.

10. RECO - EDCs, as operators of the energy grid, are in a position to identify grid needs and deploy storage and other DER solutions for the benefit of all customers, including for reliability and deferral of traditional distribution grid investments.

    Dispatchable energy storage can play a role in managing the integration of intermittent renewable or variable sources of energy, absorbing excess generation on feeders and circuits to reduce system voltage during light load conditions and allowing excess generation to be dispatched at peak times mitigating demands on the electric delivery system. Integrating DER with the electric distribution system will also facilitate the efficient use of EDC infrastructure, because it will reduce power loss in the EDC's transmission and distribution system.

    As the penetration of DER increases across the Company's service territory, the requirements, opportunities, impacts, and challenges generated by DERs continue to expand. There will be an increased and ongoing need for situational awareness and control which will require systems and applications to acquire data and produce actionable information in a near real-time environment. Establishing the appropriate level of monitoring and control is critical to realizing optimization of the grid and gaining the highest value from interconnected DERs. EDCs will need to be able to invest in the systems and applications needed to facilitate the increase in DER and provide visibility into the grid.

11. POWED - Acceleration of energy storage adoption in three markets; BTM, IPP and utility owned/operated.

    Need more cost data on transmission and distribution expenditure for management of load pockets.

    Expedited interconnection studies.

    More utility filings for energy storage.

20. SUNOWNER - Integration of DER with real time communication for dispatch is essential for the operation of a smart grid. Storage can react much faster and more efficiently than our current grid that needs to be overbuilt to remain reliable.

Item 9. How might DER be incorporated into the electric distribution system in the most efficient and cost-effective manner?

1. PSEG - Please see response to question 8.

2. CEG - The state should encourage competition by incentivizing third party and customer ownership of DER, enabling aggregators to enter markets, limiting utility ownership and ensuring that DER can provide and be fairly compensated for the broadest possible set of benefits. Industry-friendly long-term supports such as rebates and incentives are more useful in growing the market than one-off or time limited supports such as grant programs and bridge funding. NJ should follow the lead of MA and move from grants to incentives, including a storage adder in existing renewables incentive programs, a storage rebate and/or incorporating storage into the state's energy efficiency fund to enable peak demand shifting. See CEG's upcoming report on energy storage in EE programs, also MA SMART solar docket.

3. NJDRC - See Rate Counsel response to item 6.

4. OMNES - The most cost-effective and efficient way to incorporate DER into the electric distribution system is to focus first on large industrial and commercial users of electricity since the payback is much faster. This is particularly true with operational storage modes such as FR and demand charge reduction since benefits can be seen immediately. With renewables, there is the additional time and cost of constructing renewable generation sources which may be done in a second phase of DER integration.

5. JCPL - Much like with the deployment and integration of energy storage technologies, New Jersey's EDCs are in the best position to increase the value customers realize from DERs by ensuring their efficient and cost-effective incorporation into the EDCs' systems. When sited at optimal locations and owned and operated by the EDC, DERs can provide benefits to the distribution grid, including reducing peak load, providing voltage support, improving reliability and resiliency, and reducing line losses. Additionally, as mentioned previously, these benefits an be further extended by coupling the DER with energy storage to mitigate the impact caused by the intermittent nature of the DER. DERs can also be used by EDCs to benefit their transmission systems by providing frequency regulation to stabilize the grid during contingencies. In all cases, the EDCs and their customers receive greater benefit from the deployment of DERs by allowing the EDCs to drive their development based on the unique needs of their systems.

6. NJCF - See the answers to the previous questions.

7. NJR - The response to question 6 indicated opportunities by market segment, including leveraging storage in commercial buildings to reduce demand charges and as a non-wires alternative for utilities to defer transmission and distribution investments. Incentives will

be needed to support project economics and private and utility ownership models should be considered.

8. MSS - In the context of the ESA, the incorporation of DERs with non-controllable and intermittent fuel sources are the most challenging, and in need of the most careful planning and study. Therefore, MSSIA's answer to this question will focus on those DER's with non-controllable and intermittent fuel sources (primarily wind and solar).

   Identifying the most efficient and cost-effective manner to incorporate these types of DERs into the grid is not a simple matter. The fundamental challenge in integrating such DER's into the grid while maintaining reliability is matching generation to load on a moment-by-moment basis. Recent research has emphasized a variety of different methods of accomplishing grid reliability rather than placing the lion's share of the task on storage deployment. Those methods include:

   1. Generation mixing
   Different DERs have different temporal generation profiles, so they can be combined in careful quantities to improve the matching of generation to load. Solar and wind, in particular, can be combined in this way to improve the match. Sustainable biomass, a controllable fuel source, can help to an extent, limited by the amount available.

   2. Geographic mixing
   As renewable resources like solar and wind are mixed over larger and larger geographic regions, the differences in climate will cancel out intermittencies, producing a smoother generation curve, and one that can be matched to load better. Ultimately, long-distance transmission across time zones will play an important role.

   3. Smart inverter functions
   The inverters used in solar power systems have built-in functions that can perform grid stabilization services. Voltage ride through, frequency ride-through, ramp rate control, and volt-VAR control are all built in. Volt-VAR control, in particular, is a powerful tool for maintaining steady voltage in distribution circuits. The capabilities are available at no cost since they are standard features, although there may be a small loss of energy in using some features. The scale of the capability is massive, with gigawatts of inverter capacity available, distributed throughout the state.

   4. Generation shaping
   Curtailment of solar and wind is a measure that can prevent oversupply of those DERs when they are at high penetration levels. Research such as the Minnesota Solar Pathways study suggests that curtailment can be more cost effective than storage in many circumstances.

   5. Load shaping
   Shaping generation to match load is not the only way to accomplish the match; the reverse can also be effective. There is physical load shaping (i.e., demand side

management) in which loads are curtailed or increased when needed, either locally in direct response to changes in the grid or, more often, remotely controlled. There is also economic load shaping (i.e. real-time pricing) in which people are induced to make economic decisions to curtail or increase their power usage when needed.

6. Energy storage
No matter how much the previous five methods are employed, it is evident that in a high penetration renewable future - like New Jersey's 50% by 2030 and 100% by 2050 goals - very large amounts of storage will be required. The cost of battery storage is falling rapidly, but the cost of storage at the scale needed will still be high.

One way to mitigate the cost is to have the storage provide additional value by performing other functions in parallel with grid stabilization, such as emergency backup power functions for critical facilities.

Another potential way of mitigating the cost of storage is to utilize electric vehicle batteries.

MSSIA's analysis indicates that if one-third of the vehicles in the state are electric vehicles, the total storage in their batteries will reach about 180,000 megawatt-hours (MWH). This swamps the stationary battery capacity required in the Clean Energy Act. There are many challenges to be addressed in utilizing that EV storage capacity to help accommodate renewable energy on the grid, but even a small fraction of the total capacity would be of great importance in ensuring a reliable grid at high renewable penetration levels. MSSIA believes that it would be a great error to spend large sums of money on electric vehicle charging infrastructure without incorporating the bi-directional capability required for vehicle-to-grid (V2G) operation.

The aggregation of very small energy storage (e.g., residential) systems into virtual power plants may play a role in MSSIA also believes that efficient and cost-effective deployment of storage may be aided by having utility companies act as aggregators of energy storage assets in order to utilize - and monetize - the capabilities of those assets in both the distribution system and the transmission system, as others have suggested.

9. SP - We encourage program designers to remain neutral to the specifics of DER deployments (size, location, behind-the-meter or stand-alone, renewables colocation, etc.), and instead assign funding based on the value created by specific use cases, allowing developers to make business decisions resulting in the most efficient and cost-effective deployment of individual assets and portfolios of resources.

   The Board should ensure that this incorporation process is as clear and streamlined as possible. Utility interconnection applications and reviews should not discriminate against renewable projects paired with energy storage. Unnecessary delays and indefinite discussions with an electric company in the absence of clear rules and standards drives up costs to the end customer, and can also discourage private sector engagement in the state.

10. RECO - As discussed above, it is important to understand the costs and benefits of DERs in the context of the services and capabilities they can provide. Of particular interest is the identification of whether those benefits are tangible, such as revenues or cost savings, or intangible, such as increased resiliency and operational flexibility.

    Investments in DERs should recognize the value being provided relative to the investment and prioritize those investments that provide greater value to all customers. Today's electric delivery systems are built to perform under peak conditions. Understanding the impact of DERs on system peak, and the ability of energy storage to increase coincidence of renewable generation during peak load conditions, is critical to understanding the broader value of DERs including storage for customers and for the electric grid. It will be important to prioritize the deployment of BTM retail energy storage systems in conjunction with programs such as demand response that provide a peak load reduction benefit to the energy grid as well as incorporate the appropriate rate design. Further, the appropriate level of compensation must be provided to customers with storage systems for the energy dispatched so that the storage asset owner and all other customers bear the appropriate costs of the storage systems while recognizing the benefits provided by the system.

    EDCs understand their distribution systems and the needs of and locations where energy storage systems can provide a great deal of value. EDC ownership and operation of energy storage systems may unlock the ability to realize a broader range of storage benefits for all customers due to the EDC's knowledge of, planning for, and operation of its distribution system. As such, EDCs should be permitted to own storage assets, especially in the near-term to assist in meeting the State's 2021 storage deployment goal.

    Moreover, an interconnection process that is transparent and lays out a clear, well-defined set of rules and procedures is the first step to incorporating DER into the electric distribution system. Developing rules and processes for interconnection standards, metering, asset configuration, and other operational characteristics will provide certainty to developers and the EDCs alike. For example, development of a process for interconnecting a storage system at a location where solar is already present will allow for a more efficient interconnection process. The current regulations should be reviewed to determine whether they adequately guide storage systems.

11. POWED - Utility owned or dispatched storage for FTM projects due to the following:

    A- Utility has low cost of financing.
    B- Rate-payers ownership is most socially fair.
    C- Utility deployments address grid challenges that are aggregated for many customers in a load pocket.
    D- Utilities can procure through professionally run and managed RFP's ensuring low cost of supply.

12. SUN - As a restructured electricity market, New Jersey must support the participation of competitive suppliers and developers in the marketplace so that consumers are empowered to choose the energy services most affordable for them and their families. Upholding principles of competition not only drives down costs but is critical for the state's goals of greater diversity, economic development and community revitalization. Competition enables market players from under-served and underrepresented communities to contribute to our modernizing grid as entrepreneurs and owners of DER.

    As mentioned above, Sunrun has successfully engaged in similar proceedings launching battery storage pilots and regulatory platforms across the country. Last month, Sunrun won a bid to deliver aggregated residential solar and batteries as a source of energy capacity to the ISO-NE, the grid operator for one of the largest electricity markets in the United States. Sunrun will provide 20 MW of energy capacity from Sunrun's Brightbox residential solar and battery systems to ISO New England beginning in 2022, which represents approximately 5,000 New England customers.

    Additionally, in a recent proceeding before New Hampshire Public Utilities Commission, Sunrun was instrumental in working with stakeholders and the utility to come to a settlement on an innovative pilot program that will utilize customer-sited energy storage for peak load reduction and deliver savings and other benefits throughout the utility's service territory. Sunrun submitted expert testimony advocating for the inclusion of a "bring-your-own-device" ("BYOD") program in addition to the utility's proposed utility-owned battery program to allow customers to participate in the pilot through third party (non-utility) providers and aggregators. In approving the Settlement Agreement, the New Hampshire Commission specifically noted it statutory obligation to consider the pilot's "effect on competition within the region's electricity markets and the state's energy services market" and found that "utility ownership of DERs [distributed energy resources], such as customer-sited battery storage systems, may affect the competitive market for such products and services" and that the inclusion of the BYOD would serve to mitigate potential negative impacts on competitive markets.[2]

    Further, Sunrun contributed to PSE&G Long Island's Utility 2.0 Long Range Plan 2018 Annual Update proceeding. Sunrun provided detailed recommendations for improving PSE&G's proposed Behind-the-Meter Energy Storage and Solar Program, including clarifications to market rules and providing up-front pricing for integrating cost-effective DER solutions to meet short-term and long- term grid needs and recommending the program be expanded across PSE&G's Long Island territory. The New York Department of Public Service echoed Sunrun's recommendations and proposed PSE&G LI "initiate an open solicitation of third party aggregators to install energy storage solutions paired with solar, while also providing load relief through direct load control" and recommending that PSEG LI "pursue the BTM Energy Storage and Solar Program and expand it outside of load constrained areas on Long Island to be available system wide, to all classes of ratepayers, and include both paired solar PV and energy storage projects as well as standalone energy storage projects designed to reduce customer load during utility demand response events."[3]

21. SUNOWNER - DER needs to be incorporated fully with costs and revenues aligned to the real-time costs of producing energy and transparent price signals made available to encourage the most cost effective investment as the future intelligent grid evolves.

Item 10. In the context of the ESA, what might be the definition of Energy Storage?

1. PSEG – Energy Storage might be defined as the means to capture and store energy for discharge in the future at prescribed intervals for grid operational benefits.

2. CEG - The general definition is any technology capable of absorbing, storing and discharging energy at a later time.

3. NJDRC - FERC Order 841 issued in February 2018 defines an electric storage resource as a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid. Rate Counsel agrees that the resources included this definition should be included, but also believes that any definition of Energy Storage should include low-tech and low-cost options such as thermal energy storage technologies, ice energy technologies and hot or chilled water storage, which can be used to shift load at a fraction of the cost of technologies such as battery storage. Rate Counsel also emphasizes that the Board should avoid earmarking incentives for specific technologies. Any development initiatives for storage should rely on competitive market mechanisms to assure that the most cost-effective technologies are implemented.

4. DRN - Direct Energy/CBS propose that the definition of Energy Storage within the Energy Storage Analysis be defined such that eligible energy storage systems include chemical, thermal, or mechanical storage systems.

5. OCE - See the WA Commission's policy discussion of energy storage. https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=237&year=2016&docketNumber=161024 they recognize that it can be treated, for purposes of modeling, as generation, transmission and distribution.

6. OMNES - Energy storage can be defined as follows: The storage of energy captured at a certain period of time and delivered for use at another time. The form of energy captured and stored may be different from the form of energy that is delivered. The energy that is stored may be kinetic (flywheels), chemical (batteries), physical (compressed gas), gravitational potential (pumped hydropower storage), electrical potential (super-capacitors), latent heat (ice), and elevated temperature (molten salts).

7. INGER - The definition of Energy Storage should be broad enough to include thermal storage, flywheels, and other technologies, beyond electric batteries. New Jersey should consider the following definition:

    > Energy Storage is defined as commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy using mechanical, chemical, or thermal processes.

The New York State legislature has used similar language (see NY S. 1611, 2019) as has Massachusetts (see MA H. 2831, 2019).

8. JCPL - For purposes of preparing the ESA, JCP&L proposes that the Board look at all energy storage resources in the state. This is consistent with the language of the Act, which does not distinguish between different types of energy storage resources or the time at which the resource was installed. Generally, energy storage refers to infrastructure that allows for the on-demand absorption and release of electrical energy into the electric grid in parallel. JCP&L recommends that the Board be guided by this general understanding of energy storage for purposes of the ESA. Examples of energy storage resources include pumped-hydro storage systems, compressed-air energy storage, compressed gas storage systems, battery-based AC energy storage systems, flywheels, and electrochemical capacitors - to name a few. These different energy storage resources can all provide benefits to the electric grid and the EDCs' customers and, accordingly, should be considered as part of the ESA.

9. NJCF - We recommend the BPU consider defining energy storage, for the purpose of the ESA, as " systems electrically connected to the electric grid, whether behind the meter or in front of it, that convert electricity from or deliverable to the grid to some other form, store it for a period of time, and then reconvert the stored energy to electricity for either redelivery to the electric grid or for a direct end use." This would address flywheel, gravity-based, batteries, capacitor, compressed air, and similar forms of storage and which are the most prevalent and promising current storage technologies. It would not cover such intermedia time-shifting technologies as ice or molten salt thermal storage that is used for a direct end use such as heating or cooling. However, such uses are better treated as examples of flexible load, since they do not involve the additional step of converting the stored energy back to electricity.

10. NJR - We agree with the definition in FERC Order No. 841, which defined storage as "a resource capable of receiving electric energy from the grid and storing it for later injection of electricity back to the grid." The FERC interpretation accommodates resources located on transmission, distribution system, or behind-the-meter systems, and is technology neutral.

11. MSS - In the context of the ESA, MSEIA believes that the definition of energy storage could be:

    "An energy storage system is a system capable of storing energy from the electric grid and delivering the stored energy back to the grid at a later time to serve a policy objective."

    Alternatively, in order to include technologies, such as ice storage, that can deliver equally valuable storage services to the grid by avoiding energy usage whenever desired, the definition could be:

"An energy storage system is a system capable of storing energy from the electric grid and delivering the stored energy back to the grid at a later time, or avoid the usage of power from the grid at a later time, to serve a policy objective."

12. SP - "Energy Storage" should be defined as any device capable of absorbing energy from the grid or a collocated generation resource, storing that energy for a sustained period of time (e.g., 24+ hours) at with a high level of efficiency (e.g., 80%), and dispatching that energy back to the grid in an active and controlled fashion. Beyond these common operation requirements, the ESA should be technology-agnostic.

    Resources intrinsically capable of independent energy generation should not be categorized as Energy Storage; however, Energy Storage systems located behind the same point of common coupling with the distribution system as generation resources should not be prevented from participation in the ESA. Energy Storage devices co-located with generation resources should be allowed to have either AC-coupled or DC-coupled configurations and have equal treatment by the ESA for all programs for which they can demonstrate compliance with operational requirements.

13. RECO - RECO defines energy storage as any technology capable of charging from the grid or DERs and storing that energy through electrochemical, thermal, kinetic or other means for discharge at a later time.

14. SUN - Energy storage is defined as devices that absorb energy, store that energy for a period of time, and, thereafter, dispatch for consumption. In other words, storage enables an input of energy to be released for use at another time. Energy storage separates the time of generation from time of consumption which enables opportunities to optimize the efficiency and cost effectiveness of the energy delivery system.

15. SUNOWNER - Energy storage is not only electric storage but should include thermal storage, usually in the form of ice storage for supplying peak demands during the summer air conditioning season. Thermal storage is less expensive per MWH than electric storage and does not reduce in capacity as quickly as electric storage. Energy storage is any electric or thermal storage that displaces energy that would otherwise need to be produced and consumed in the same moment.

Item 11. What discharge time duration could be applied to the State goals of 600 MW of energy storage by 2021 and 2,000 MW of energy storage by 2030? Four hours? Ten hours? Other?

1. PSEG - PSEG does not have an opinion on the optimal time duration to be applied to the State's goals. Most of the applications PSE&G proposed in its CEF-EVES filing utilize 4 hour duration storage systems because it was both suitable for the majority of likely applications and appeared to be the standard offered by many original equipment manufacturers.

2. CEG - The question should be how the state will define "peak" with regard to peak-shifting policies such as a clean peak standard or other peak demand reduction goals. "Peak" should be defined relatively narrowly, for example, as the top 10% of the hours in a year, either by price or by demand, with discharge requirements limited to 4 hours maximum (three or fewer hours is preferable).

3. NJDRC - Rate Counsel believes this question would be best answered by: (1) the Rutgers study; (2) New Jersey EDCs; and (3) PJM. Rate Counsel notes that the PJM compliance filing (see last question below) requires that energy resources must be capable to providing 10 hours of continuous energy in order to bid into the capacity market. The FERC is still reviewing this proposal and a final Order has not been issued to date.

4. DRN - Direct Energy/CBS believe that different discharge time systems are valuable for different grid and customer usages, so mandating a single duration standard for compliance would not be recommended. Given the research in other jurisdictions (e.g. Astrape in NY) pointing to the capacity value of four-hour storage, one option would be to convert the 600MW and 2000MW into relevant MWh targets (2400MWh and 8000MWh) and incentivize systems according. For example, offer a declining-block $/MWh incentive at 100% for the first four hours, 50% for hours five and six, and 0% for further hours. This would balance between the various duration demands on the system.

5. OMNES - Four hours would allow for greater distribution of energy storage resources (ESRs). Mandating ten hours would bias energy storage systems toward very large installations such as pumped hydro which is by its very nature is not easily distributable and has the disadvantages of high transmission losses, regulatory hurdles, long times to implement, and unanticipated expenses.

6. INGER - New Jersey policymakers should have a flexible approach to deciding the appropriate energy storage duration based on its state goals of 600 MW by 2021 and 2,000 MW by 2030. Maintaining flexibility is important because the optimal energy storage duration varies by use case. For example, behind-the-meter TES use cases are typically six to eight hours, while other use cases for wholesale services and frequency regulation might be four hours or as little as 30 minutes. By maintaining flexibility on

duration, policymakers ensure that the appropriate technology is optimally matched with the grid conditions or symptoms it is being asked to solve.

7. JCPL - The appropriate discharge time duration to be considered for an energy storage resource depends on the functional purpose for which that resource is operating. Accordingly, this question cannot be answered definitively without knowing the function the various energy storage resources will be performing.

8. NJCF - NJCF recommends that the BPU base its implementation of the statutory storage goals on the results of its initial integrated planning, as described in these comments and in NJCF's comments on the Energy Master Plan of October 12, 2018. In particular, the rated power, rated capacity and discharge time dimensions of those goals should be informed by such analysis, since the likely needs, costs and benefits of those characteristics can best be determined by looking at the regional balancing market dynamics expected in and across typically high and low VRE producing hours in those years. The economic value of the mandated capacity in the PJM BRA certainly could matter for the 2021 goal, but should not be the only consideration. PJM's current Manual 21 requirement for storage to participate in PJM's BRA, namely that the storage resources eligible capacity (in the power plant sense) be based on how much energy the storage resource can discharge over 10 continuous hours, would certainly affect the capacity market value of the 2021 goals -- if it is maintained. It is not clear that the current Manual 21 requirement will be maintained or, indeed, that it is needed for reliability or efficient operation of the BRA. Accordingly, NJCF recommends the BPU look primarily at the implications of integrated energy planning in terms of the rated capacity, rated power and discharge times most likely to be needed in the 2020's, and use these results in further specifying the types of storage to be considered for the 600 MW 2020 goal. Indeed, any such planning results could be very helpful in supporting a more efficient treatment of storage in PJM's capacity market. The 2030 goal, in turn, would be better addressed in the mid-late 2020's, when more information is available about new storage technologies and new system needs.

9. NJR - The appropriate discharge time will vary based on the application of the energy storage system. Other than large-scale pumped storage systems, most batteries are designed to support up to four hours of storage and should be sufficient for most applications. A sliding scale incentive value, based on the duration of the battery, could be considered.

10. MSS - The requirement in the Clean Energy Act is expressed as 600 megawatts by 2021 and 2,000 megawatts by 2030. The storage requirement is expressed in megawatts, a power rating. Every grid-connected energy storage system has a power rating (e.g., megawatts [MW]), as well as an energy rating (e.g., megawatt-hours [MWH]). Most storage systems consist of an energy storage sub-system and a power conversion sub-system, which is usually an inverter. The power rating is the rating of the inverter, while the energy rating is the amount of energy that can be stored and delivered by the storage sub-system. Since the Act expressed the requirement as a power rating (megawatts),

MSSIA believes that the total power rating of storage built in the state should be the measure of compliance. That being the case, the time duration of the battery storage system will not be relevant to compliance with the act.

Further, different time durations will be appropriate for different applications (e.g., solar and storage systems for resiliency, microgrids, systems designed primarily for frequency regulation, etc.) It would be very inefficient to specify a particular time duration for compliance or for any incentive; systems requiring less time duration than specified would be burdened with unnecessary cost, while those requiring more than specified would be disadvantaged in receiving incentives.

MSSIA believes that the average discharge time duration during the early years between now and 2030 might be between two and three hours. After that, as renewable penetration reaches higher levels and the cost of storage drops, time shifting of generation for several hours is likely to become more of a priority. That is expected to cause a trend toward more hours of discharge time duration.

11. SP - As discussed in our response to Question #1 above, the value streams available to an energy storage device diminish as a function of duration. In this way, a 10-hour storage system offers less value to the grid than a 2-hour storage system on a per-MWh basis. If program designers established a 10-hour minimum duration for energy storage systems, the resulting program would very likely either fail to meet MW deployment goals or over-compensate the resources used to meet those goals.

    For this reason, we recommend either establishing a relatively short minimum duration requirement (e.g., 2 hours) and establishing calculations for additional funding as a function of longer runtimes, as in the SMART program implemented by the Commonwealth of Massachusetts.

12. RECO - Storage duration should be considered in terms of the intended application. Discharge times for a frequency response asset may be considerably shorter in duration than for a distribution deferral asset. It is the Company's experience that energy storage systems are best considered both in terms of capacity and energy (i.e., MW and MWh). To meet the State goals, RECO recommends that the storage capacity be sustained for a period of a minimum of four hours. This period will accommodate durations for most use cases where energy storage is being deployed.

13. TESLA - As a baseline, Tesla recommends that New Jersey apply a minimum four-hour duration to the State goal of 600 MW of energy storage by 2021. As discussed below, multiple studies have found storage with a four-hour duration to provide significant system benefits and receive a full 100% capacity value. The four-hour duration enables many potential use cases for energy storage including short-duration use cases such as frequency regulation that stabilizes the regional grid and longer-duration use cases such as peak shifting and capacity.

For its goal of 2,000 MW of energy storage by 2030, Tesla suggests that New Jersey evaluate its system needs to determine the most valuable mix of durations to its system based on learnings around successful models in New Jersey, projected peak demand, and projected renewable penetration levels. While a four-hour duration has proven to be optimal for many systems, it is likely that storage of varying durations would be appropriate, particularly as grid conditions change.

As mentioned above, recent rulings and studies have shown that electric storage resources with four-hour durations can provide significant capacity value in many systems. In 2014, the California Public Utilities Commission established that for energy storage, Qualifying Capacity values would be based on the resource's ability to generate power "for at least four consecutive hours at a maximum power output (PmaxRA), and to do so over three consecutive days."8 This determination continues to govern the participation of energy storage in California's Resource Adequacy construct.[9]

The National Renewable Energy Laboratory ("NREL") released a report in 2018 assessing California's four-hour requirement and determined that storage resources with a four-hour duration could receive 100% capacity credit. To arrive at this determination, NREL approximated the capacity credit of energy storage by evaluating its ability to reduce the peak net demand for electricity based on the day of peak demand in California. NREL determined that conservatively, up to 3,000 MW of energy storage in California could receive the 100% capacity credit. NREL determined the amount of four-hour energy storage resources that could receive 100% capacity credit, by analyzing the "shape" of the peak demand period and identifying the point at which the ability of an incremental unit of four-hour storage to reduce peak demand would drop to below 100%. NREL also noted that the amount of solar PV on the system affects that amount of storage that can provide 100% capacity, specifically that beyond 11% PV penetration, the potential of four-hour storage increases.10

In 2016, the management consulting company ICF International, Inc. ("ICF") evaluated the potential of energy storage to provide firm capacity in the Electric Reliability Council of Texas ("ERCOT") system. ICF found that energy storage systems with a duration of four hours or higher could capture a 100% capacity value on the ERCOT system. ICF performed its study by identifying the hour with the highest Loss of Load Expectation ("LOLE") and evaluating the improvement in LOLE from adding storage availability in that hour. ICF repeated the process for one-, two-, three-, four-, five-, and six-hour energy storage systems. ICF's study highlighted that energy storage with durations lower than four hours can also provide partial capacity benefits, finding that "100 MW energy storage system with 1-hour of stored energy can provide 46 MW of firm capacity, while a 100 MW storage resource with 4-hour of stored energy can provide 99 MW of firm capacity This study suggests that requiring extended runtimes beyond four hours for electric storage resources like energy storage is not required to provide firm capacity, and that the extended hours may provide little additional value.

14. POWED – Four hours.

15. SUNOWNER - A four hour minimum discharge requirement is proposed for incentivizing in New York under their new storage regulations, with lower incentive amounts per hour for additional commitment for hours in excess of four discharge capacity. Discharge requirements for additional MWH systems should be developed as lessons are learned from the initial 600-800 MWs deployed.

Item 12. What storage systems should be counted towards the achievement of the State's goal? Existing systems? Those systems placed into operation after the May 23, 2018 enactment date of the statute?

1. PSEG - PSEG defers to the BPU, the legislature and Governor Murphy as to whether existing storage systems should count towards the State's goal of 600 MWs by 2021.

2. CEG - Those systems placed into operation after the May 23, 2018 enactment date of the statute.

3. NJDRC - All storage systems currently in place plus those placed into operation after the May 23, 2018 enactment date of the statute should be counted towards achievement of the State's goal. The Clean Energy Act specifies a goal of 600 MW of energy storage by 2021 and 2,000 MW of energy storage by 2030, but does not state that this would only apply to systems placed into operation after the enactment of the statute. Any incentives for storage technologies, however, should be available to new systems only.

4. DRN - Direct Energy/CBS believe that systems placed into operation after publication of final program rules, or after the May 23, 2018 enactment date of the statute, would be a reasonable benchmark for inclusion.

5. OMNES - New installations after the May 23, 2018 statute enactment date should be counted towards the achievement of the State's goal. PJM currently states that is has 5,300 MW of energy storage resources, of which 96% is pumped hydropower storage. However, it is not clear for how many hours the 5,300 MW is delivered.

6. JCPL - As mentioned previously, the Act does not distinguish between the different types of energy storage resources that have been discussed herein. Rather, the Act requires the Board to "initiate a proceeding to establish a process and mechanism for achieving the goal of 600 megawatts of energy storage by 2021 and 2,000 megawatts of energy storage by 2030." N.J.S.A. 48:3-87.8(d). The Board should follow the Act's mandate and count all energy storage resources towards achievement of New Jersey's goal, regardless of the specific type of resource or when it was installed.

7. NJCF - NJCF does not, at this time, make a recommendation regarding the treatment of existing vs. incremental storage in terms of counting towards the statutory goals, other than the recommendations above that the type and quantity of storage to be developed in New Jersey be evaluated primarily on the basis of need and cost-effectiveness in supporting the state's renewable energy, clean energy and global warming response goals.

8. NJR - While technology neutral, we would recommend that New Jersey focus its efforts on developing a program and designing incentives to support battery storage applications. Thereafter, the program can be broadened to accommodate other types of storage

technologies. Incentives should be limited to new systems. Given only 7.5 MW installed, this should be a minor issue.

9. MSS - MSSIA believes that storage systems placed into operation after the date of enactment of the Clean Energy Act should count toward the achievement of the storage requirement of that act.

10. SP - We recommend that only those storage systems placed in operation after enactment of the statute be counted toward the achievement of the State's goal.

11. RECO - The Board should count toward achievement of the State's goal, all energy storage that exists on the system regardless of when it was installed. However, incentives or other policy drivers of energy storage that result from the Board's Energy Storage Analysis should be applied solely to new energy storage systems. EDC customers should not pay for increased compensation to owners and developers of existing, financed, and operational energy storage systems for risks already taken and costs already sunk.

12. POWED – After May 23, 2018.

13. SUNOWNER - There is essentially no storage current beyond a few systems and about 200 residential systems (less than 2 MW), so they do not need to be counted toward that goal unless they participate in future NJ capacity participation programs.

Item 13. How might Federal Energy Regulatory Commission's (FERC) Order 841 and the associated PJM compliance filing affect the foregoing?

1. PSEG - In December 2018, each of the nation's RTOs and ISOs submitted filings to FERC detailing how they plan to satisfy the mandate that they accommodate the participation of energy storage resources. PJM represented that while its markets already offer a number of products that participating storage resources can provide, it had to develop a series of tariff changes to ensure that such resources are eligible to provide all services they are technically capable of providing ("Energy Storage Resources (ESR) Participation Model") (ER19-49).

   In a separate filing, (ER19-462), PJM submitted an accounting framework for storage resources capable of serving retail load ("Energy Storage Resources (ESR) Accounting Proposal"). Specifically, PJM proposed to define "Energy Storage Resource" as "a resource capable of receiving electric energy from the grid and storing it for later injection to the grid that participates in the PJM Energy, Capacity and/or Ancillary Services markets as a Market Participant" and to define a "Capacity Storage Resource" as "any Energy Storage Resource that participates in the Reliability Pricing Model or is otherwise treated as capacity in PJM's markets such as through a Fixed Resource Requirement Capacity Plan." Prior to this filing, PJM's Tariff limited an Energy Storage Resource to specific technologies (i.e., flywheel or battery storage facilities) and resources injecting "solely" to the wholesale grid. The proposed revisions included removing the "solely" concept to support the fact that the resource may also provide retail service yet still be eligible to buy and sell power at wholesale when not providing such retail service. PJM requested that the ESR Accounting Proposal revisions become effective February 3, 2019. The requested February 3, 2019 effective date was intended to allow PJM sufficient time to develop and test its metering and accounting practices prior to implementation of the ESR Participation Model on December 3, 2019.

   On February 1, 2019, FERC issued a letter order accepting PJM's ESR Accounting Proposal compliance filing, effective February 3, 2019, as requested. The ESR Accounting Proposal should presumably help position the PJM markets to support the State's storage program. In this regard, the ESR Accounting proposal should help facilitate PSE&G's CEF-EVES filing. Addressing the complexity of implementing proper accounting and settlement practices is a critical piece to developing a strong and sustainable ESR market in New Jersey and throughout PJM.

2. CEG - There are many ways in which PJM's compliance will affect the ability of energy storage to come to scale in New Jersey. For example, ISO-New England defines peak as a 2-hour duration period, while PJM defines it as a 10-hour duration period. The PJM definition is overly broad and not helpful given the operational attributes of energy storage. Also, defining so many hours as "peak" hours means that the value of reducing any given peak hour load is small. FERC's order should open markets and level the playing field, but individual ISO compliance is where the real change has to happen.

States should communicate to PJM about market rules that need to change in order to support the growth of DER markets. Also, states should take market opportunities and barriers into account when designing incentive programs for DER.

3. NJDRC - PERC Order 841 was issued in February 2018 and is intended to "remove barriers to the participation of electric storage resources in the capacity, energy and ancillary services markets operated by Regional Transmission Organizations and Independent System Operators."[5] The Order directs regional grid operators to revise their tariffs and develop rules that recognize the physical and operational characteristics of electric storage resources and facilitate their participation in regional markets. Regional grid operators were required to submit their compliance filings by December 3, 2018.

   PERC Order 841 outlines five core concepts that each grid operator must adhere to:

   1. ensure that a storage resource is eligible to provide all capacity, energy, and ancillary services that the resource is technically capable of providing;
   2. ensure that a storage resource can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer;
   3. account for the physical and operational characteristics of electric storage resources through bidding parameters or other means;
   4. establish a minimum size requirement that does not exceed 100 kW; and
   5. specify that a storage resource will pay the wholesale locational marginal price for charging energy.

   The PERC Order allows storage to be on the same playing level as traditional generation resources and potentially compete with resources like peaking plants. This could encourage larger utility-scale projects and lead to a decrease in cost. It may also allow projects located in New Jersey to provide service throughout PJM and reduce the need for state-provided incentives. Again, Rate Counsel looks forward to reviewing the analysis prepared by Rutgers, its estimates of storage technology costs and benefits and the potential impacts of FERC Order 841 and P JM compliance.

4. DRN - Direct Energy/CBS believes New Jersey should support efforts towards a FERC order on aggregated DER because well-written rules around aggregation allow for additional value to be created for system operators, utilities and stakeholders. At its core, aggregation allows individual resources who cannot reliably meet specific program requirements on their own to be utilized as part of an aggregate that can be more reliable in delivering value. We have seen this in multiple markets, especially in Europe where not only is the risk of a single asset failure minimized, but the delivery of key services is proven more efficient by allowing a wider and more diverse set of resources to participate in the market.

5. OCE - PJM's proposal would require storage to offer energy continuously for 10 hours in order to bid into the capacity market. This is a pretty long time and storage developers say that it will result in significant derating of capacity, and even then may not facilitate participation in the capacity market. It remains to be seen whether this requirement will

meet FERC's requirement that the ISOs "account for the physical and operational characteristics of storage resources."

PJM has proposed an accounting framework that effectively requires all charging by energy storage resources that are not owned by load-serving entities to discharge back to PJM, meaning they can't sell to others or use the stored power themselves.

6. OMENS - PJM's compliance filing favors pumped hydro which has been the status quo to date. In fact PJM will push back on true distributed energy storage resources that can be co-located at the load (customer) to provide fast implementation and minimizes installation and transmission costs. It may be wise to remove pumped hydro as a DER since it is not a DER!

7. JCPL - On February 7, 2019, the FirstEnergy Utilities[2], The Dayton Power & Light Company, and East Kentucky Power Cooperative, Inc. (collectively, the "Joint Utilities"), jointly filed their protest and comments in response to PJM's Order 841 compliance filing. In those comments, the Joint Utilities encouraged FERC to require PJM to defer to EDCs, in consultation with affected state commissions, "on implementation and coordination issues at the electric distribution level regarding the PJM ESR Proposal." (Attachment A; Protest and Comments of The FirstEnergy Utility Companies, The Dayton Power and Light Company, and East Kentucky Power Cooperative, Inc., Docket No. ER19-469-000, at p. 3). Specifically, the Joint Utilities pointed out that EDCs have mandates under state law "to deliver reliable and safe electric power to retail customers" and accordingly (with support of their state commissions) "must develop, implement or augment numerous processes, rates, and tariffs that are specific to [energy storage resources]." (Id. at 1-2). The Joint Utilities thus supported a "deliberate approach to the large-scale deployment of [energy storage resources] onto the electric distribution system." (Id).

   JCP&L's comments herein are consistent with the Joint Utilities' comments and FERC Order 841. Increased deployment of energy storage resources can provide a tremendous benefit to the EDCs' systems and their customers if performed in a deliberate and strategic manner. For this to occur, the EDCs and the Board must work together to develop appropriate policies to encourage further development of energy storage in New Jersey and identify opportunities for strategic implementation that will maximize benefits to the EDCs' customers. Nothing in FERC Order 841 precludes these efforts to further New Jersey's energy storage goals.

8. NJCF - Please see our answer to question 11, above.

9. NJR - The order specifically outlines that electric storage resources cannot be discriminated against in providing all types of capacity, energy and ancillary services. Battery energy storage resources as small as 100 kilowatts will be permitted to participate, be able to set prices as generation and load, and be allowed to resell power into markets at the LMP. A formal challenge is pending, as to whether the order applies

to distribution-connected storage resources, which are largely beyond FERC's jurisdiction.

A current limitation of PJM's compliance filing for Order 841 is that resources must have a 10-hour minimum to bid into capacity markets, which will limit the revenue potential for most battery technologies today. PJM's requirements are well above those of ISO New England (2-hour), New York ISO (4-hour), and Midcontinent ISO (4-hour).

10. MSS - The primary effect of PJM's implementation of FERC Order 841 is expected to be to enable behind-the-meter storage systems to fully, and hopefully relatively easily, participate in PJM's wholesale markets, notably ancillary service markets. This will enable storage systems tied to solar power systems to participate in those markets, and thereby derive revenue to offset the costs of storage and resiliency.

11. The cost of deploying storage systems will be reduced due to the co-location and sharing of interconnection costs, and the streamlined process for interconnecting. Storage developers may also be able to take the federal investment tax credit for the storage when integrated with solar power. All of these cost and revenue benefits will enable deployment of storage to accelerate with less, if any, state incentives.

12. SP - Implementation of FERC Order 841 may create opportunities to co-optimize performance of energy storage systems in PJM wholesale markets with performance under State-sponsored programs. In order to facilitate this co-optimization, program designers should tailor programs to complement PJM requirements (e.g., implement programs with shorter duration requirements than PJM's 10-hour requirement for capacity market participation), rather than simply duplicating PJM's requirements for specific programs.

13. RECO - Order 841 and PJM's compliance filing have done much to clarify the rules for battery storage participation in wholesale markets. However, some of these clarifications limit the opportunity for batteries to receive meaningful wholesale revenues. For instance, PJM proposes that participation in its capacity market be based on ten hours discharge duration. Opportunities for dual participation may also be limited for BTM resources.

14. TESLA - FERC's Order 841 takes a step forward in removing many barriers to the participation of energy storage in wholesale markets. These changes will provide opportunities for the creation of new business models for energy storage and the potential for storage to provide additional benefits to the state.

    However, PJM's compliance filing contains two significant barriers to the participation of energy storage in its capacity market, the Reliability Pricing Model (RPM), including: (1) a wholly unsupported ten-hour runtime requirement, and (2) potential financial penalties that extend beyond the physical capabilities of energy storage resources.

First, PJM has proposed a minimum runtime requirement of ten hours for electric storage resources.13 This requirement is arbitrary and unduly discriminates against electric storage resources by not allowing them to provide all services of which they are technically capable.

The proposed ten-hour runtime requirement represents a minimum requirement for electric storage resources that is more than double the requirements that are existing or proposed for other RTO/ISO regions or is shown by existing studies, discussed above, to be necessary to achieve full capacity value. California Independent System Operator Corporation ("CAISO") currently determines the Net Qualifying Capacity of Non-Generator Resources based on the resource's sustained output over a four-hour period,14 in agreement with the California Public Utilities Commission's decision to base Qualifying Capacity values on an electric storage resource's ability to generate power for at least four consecutive hours at a maximum power output.[15]

PJM has not provided any rationale as to why system need in its territory would differ so greatly from other regions as to require such a significant increase in required minimum runtime for electric storage resources. More importantly, PJM has not conducted or submitted a study of systems needs that supports the requirement of a ten-hour minimum runtime for electric storage resources.

Tesla, as well has numerous other stakeholders have opposed this requirement in comments to FERC in the relevant proceeding, including Energy Storage Association, NextEra, Public Interest Organizations, Joint Consumer Advocates, EDF Renewables, Solar Energy Industry Association, Advanced Energy Economy, American Wind Energy Association, Solar Council, and Union of Concerned Scientists.

New Jersey should also insist that PJM develop a new proposal that allows four-hour energy storage to reasonably serve peak loads and reduce costs to consumers. Doing so would help maximize the ratepayer benefits provided by the energy storage developed to meet New Jersey's storage targets.

Second, storage resources cannot meaningfully participate in the RPM due to the significant penalties that Capacity Performance rules apply to a resource if it is not available during a Capacity Performance interval, even if the electric storage resource has provided its entire energy capacity through PJM dispatch. This structure unduly discriminates against electric storage resources and fails to account for their physical attributes.

Under Capacity Performance rules, the performance of a resource is assessed during all Capacity Performance intervals, which are unlimited and determined by PJM. For all Capacity Performance intervals during which a resource underperforms, PJM assesses a Non-Performance Charge. While Non-Performance Charges for capacity resources were developed to ensure that capacity resources performed when called, their final implementation has also led to an effective requirement that resources be able to respond to calls 24 hours a day, 365 days a year, for an unlimited number of consecutive hours. This requirement may promote performance for traditional generators that can continuously provide energy without having to recharge, but it unduly discriminates and effectively blocks participation of use-limited resources like electric storage resources, despite their proven ability to provide significant capacity value. For example, if a 100MW / 400MWh (-hour) energy storage resource is dispatched by PJM to provide 100MW of energy during a Capacity Performance event, it could comply with that dispatch for four hours. However, if the Capacity Performance event exceeds four hours, the energy storage resource will have no remaining charge and perform at zero during the subsequent Capacity Performance Intervals. It also does not make sense for the energy storage resource to place additional strain on the system by charging during Capacity Performance events, so it should not charge in preparation for later Capacity Performance intervals. Thus, for each Capacity Performance interval after the energy storage resource has been depleted -- including due to PJM dispatch -- it will receive a Non-Performance charge. The Non-Performance Charge Rate depends on the Net Cost of New Entry ("Net CONE") of the auction for that Delivery Year. At a Net CONE of $300/MW-day, the Non-Performance Charge Rate would be $3,650/MW-hour, with the maximum annual Non-Performance charge being $16,425,000— significantly more than the $6,049,145 that the resource would have earned in capacity revenue.[16]

So, because Capacity Performance rules potentially subject electric storage resources to penalties for not performing beyond the resource's physical capability, electric storage resources cannot effectively manage this financial risk, creating a barrier to participation for electric storage resources in PJM's capacity market. Tesla and SolarCity highlighted this issue in comments in 2017 comments to FERC regarding the now-approved rules for energy storage.[17]

Options for electric storage resources to pair with other resources or de-rate their capacity in order to mitigate the financial risks significantly dilute the economics of electric storage resources participation in the capacity market. This methodology also fails to accurately reflect the value that electric storage resources provide to the system.

Behind-the-meter energy storage systems also cannot effectively participate in PJM's capacity market through the Demand Response Capacity Performance rules because those rules do not currently allow behind-the-meter resources to inject energy onto the grid. This would significantly restrict the functionality of behind-the-meter energy storage resources.

These barriers to participation in PJM's RPM will reduce the ability of New Jersey's energy storage resources to earn revenue and provide value to the state's ratepayers. Tesla urges New Jersey to engage with PJM and FERC to ensure that these barriers are removed to ensure that the state can realize the full benefits of its energy storage resources.

15. SUN - It is our understanding that FERC Order 841 does not address removing barriers to the deployment of distributed energy resources. However, we are encouraged by FERC's momentum facilitating large scale storage participation in the wholesale markets and we are optimistic FERC will do the same for distributed storage.

16. SUNOWNER - Order 841 is expected to enhance the economics of storage connected to the grid by compensating the storage that can be dispatched and meet other performance requirements to enable it to earn capacity payments and sometimes ancillary services.

Other comments not in the legislative items

1. DRN - As an overarching issue, any final policy of the State of New Jersey must consider that since the passage of the Electric Discount and Energy Competition Act ("EDECA") in 1999, a large and significant competitive market has emerged and developed to meet many of New Jersey's energy needs. Private companies like Direct Energy and CBS are often better positioned than public utilities to develop and commercialize new technologies and services. Whether it be smart home technologies, combined heat and power ("CHP"), commodity and time-of-use type offers, solar products, energy measurement and management products/services, or storage the competitive market is ready and able to help solve the state's energy goals. Thus, the preferred policy of the State of New Jersey should be to encourage and incent the investment of private capital (where shareholder's properly hold the risk) as opposed to condoning the use of ratepayer dollars by the state's public utilities, thus socializing cost and risk on the residents of NJ while privatizing profits for the shareholders of New Jersey's utility companies.

   To judge how important the competitive market is to New Jersey, one must only look at the most recent switching statistics as posted on the New Jersey Board of Public Utilities ("NJBPU") website for December 2018. For the power sector, over 339,013 residential and 149,399 commercial and industrial ("C&I") accounts are with Third Party Suppliers ("TPS") totaling ~37% of the total electric load. For the gas sector, 119,283 residential and 52,047 commercial accounts are with TPS totaling ~23% of the total load. These numbers demonstrate that while additional penetration by TPS can be accomplished, the competitive market is alive and well in New Jersey and the state should be driving additional development of the competitive market to benefit all energy consumers.

   Finally, New Jersey should look at other states that have considered energy storage already and adopt best practices from those states' efforts. As an example, New York's Energy Storage Roadmap developed in mid-2018 is a robust and technically sound template which New Jersey should consider mirroring as closely as possible, particularly the recommendations on competitive procurement and third-party ownership of storage.

2. VES - Our comments below primarily touch on the topic of clean energy access and equity issues. We recognize that a path towards 100% clean energy future is not possible without energy storage solutions that address the intermittency issues associated with wind and solar technologies. Moreover, by implementing a smart electric energy storage plan, we have the opportunity to not only create a clean future but do so in a way that drives equity and resiliency.

   Energy storage coupled with solar PV can help build community resilience, an aspect of our energy system that has not received the attention it deserves. We borrow the definition of a resilient energy systems or resilient power described by Clean Energy Group as following:

"Resilient power, defined as clean, on-site, distributed generation that runs 24 x 7, 365 days a year and can be islanded (isolated from the grid to provide uninterrupted power to the host facility in the event of a grid outage…. First, it is cleaner, employing renewables, energy storage, and high-efficiency, low-emissions technologies such as combined heat and power (CHP) and fuel cells. Second, it runs year-round, providing daily benefits to the host facility, whereas diesel generators sit idle 99 percent of the time. Third, because it is designed for daily use, resilient power is more reliable than diesel backup generators, which have a high incidence of failure, in part because they are seldom used. Fourth, resilient power does not rely on deliveries of liquid fuel, which may be difficult or impossible during a disaster. And fifth, in some places, resilient power technologies can produce income for their owner/operators by allowing them to bid into electric services markets such as the frequency regulation and demand response markets, as well as reducing electricity costs through peak shifting and reduction of electricity demand charges for the host facility."[1]

While New Jersey did offer an Energy Resilience Bank at one point, our understanding is that this program is currently not active. Similarly, whereas the Renewable Electric Storage Incentive Program offers incentives for electric energy storage systems integrated with Class 1 renewable energy projects installed behind-the-meter at non-residential customer sites, to our knowledge no project to date have come online to serve low-income, environmental justice, or predominantly communities of color.

Moreover, as we learn from the lessons offered from Superstorm Sandy's recovery, we underscore the recommendations offered by environmental justice (EJ) partners in New Jersey to build resilient communities through solar and storage. Based on the current global trajectory, major storms are increasing in frequency, duration, and severity. As data shows, low-income and EJ communities are most likely to be last in receiving recovery aid and in recovering from a disaster.[2] Keeping this in mind, New Jersey's underserved communities are most in need of clean, resilient systems to ensure their safety and wellbeing during and in the aftermath of these events. Our low-income and EJ partners in New Jersey's most vulnerable communities have identified resiliency as a priority, and we are pleased to support our goals in these comments.

3. NJCF – 1. The Board's energy storage analysis should be carried out with the primary goal of advancing and supporting New Jersey's clean energy and global warming response goals.

   NJCF - NJCF urges the Board and its staff to conduct its analysis of energy storage in the context of the state's legal and policy goals for clean energy. These include:

   - The Act's aggressive goals for renewable energy to supply 50% of all energy delivered to retail customers by 2030, much of which renewable energy is to be acquired under a strict cap on ratepayer costs;
   - The requirements of the Global Warming Response Act of 2007, N.J.S.A. 26:2C-27, to reduce statewide greenhouse gas emissions, meaning the sum of annual emissions of greenhouse gases from all sources within the state and from

electricity generated outside the state but consumed in the state, to 1990 levels by 2020 and to 80 percent or less than 2006 levels by 2050; and

• The goals of Governor Murphy's Executive Order 28 for the state's 2019 Energy Master Plan to provide a comprehensive blueprint for the conversion of the State's energy production to 100% clean energy sources on or before January 1, 2050, and to provide specific proposals to be implemented over the next ten years in order to achieve the 2050 goal.

This context for the analysis is critical, since cost-effective energy storage technologies are widely considered to be an essential component of any clean energy system that includes high percentages of energy production by wind, solar and other variable renewable energy (VRE) resources. This need is due to the electric system's need to continually balance the amount of electricity generated with the amount of electricity consumed. But VRE cannot always be available to increase the amount of energy it generates in response to increases in consumption (for example, when the sun is not shining or the wind not blowing). Without clean energy solutions to this need, such as flexible load, energy storage, and zero emission but highly dispatchable generation, fossil fuels will continue to be used for such balancing purposes.

Further, high levels of VRE resources are likely to produce more energy than is being consumed during periods of ample wind or sunshine but low energy consumption. Without the ability to shift energy consumption to such periods, including by increasing electricity used to charge energy storage resources, this overproduction can only be managed by curtailing VRE or other resources, including clean energy resources. High levels of such curtailment increase costs and reduce the amount of greenhouse gas reductions that clean energy could otherwise support. Energy storage can store VRE produced at times when production exceeds consumption, and release it at times when consumption exceeds production, helping ensure reliability while reducing costly curtailment and displacing or avoiding additional greenhouse gases from fossil generation. Achieving the right amount and types of storage to produce these benefits, however, and to do so cost effectively, is a significant challenge.

2. Careful analysis is needed as part of an integrated energy planning process to identify optimal levels, types and locations of energy storage as part of an increasingly clean energy system.

Different energy storage technologies are best suited to short, long, frequent or infrequent charging and discharging, and can have very different cost and performance capabilities in these applications. Three characteristics are particularly important for electric system uses:

(a) how much energy can be stored, measured in total watt-hours that can be delivered from the device on a single charge, and often referred to as the "rated energy capacity" or "rated capacity";[1]

(b) the maximum level of power that can be delivered from the device, measured in watts, which is often referred to as the "rated power"; and

(c) how long it takes to deliver all the available watt-hours at the rated power level, often call the "discharge time".

Figure 1 in the Appendix illustrates the rated capacity and discharge time different storage technologies, and their alignment, from a UK perspective, with key needs of an electric system with growing levels of VRE production. Figure 2 shows the relationship between rated power (maximum power output) and rated capacity (maximum energy output) under the maximum discharge time levels for a wide variety of storage technologies. Both figures give a good sense of what power sector needs various storage technologies are and are not technically capable of serving.

Beyond these key features, many other characteristics of storage technologies, including their energy efficiency, cost, their expected calendar lives and the number of charging cycles they can provide, their optimal depth of discharge, and their commercial maturity all can factor into determining which technologies are the best choice for a particular application. Figure 3 in the Appendix gives an indication of the complexity of the cost and operating parameters of many storage technologies and the power sector applications they may best be suited to, at least as of 2015.2

The substantial diversity of all these parameters of various storage technologies and of the types of services they might best provide suggests an efficient, step-wise process for the Board to assess storage needs and opportunities. First, the Board would focus on identifying the types and amounts of services that New Jersey's electric system is likely to need in the next 5 to 10 years to best support its clean energy goals. Then it could encourage and support the private sector and other stakeholders to bring forward technology proposals that would best provide these types and amounts of services, at the lowest cost, and in light of the ongoing development of improved storage technologies.

NJCF recommends three key steps in this process. The first step is to determine which storage functions, and how much of each, are likely to be most needed in New Jersey as it progresses towards its clean energy goals, in parallel with other states interconnected to the same electric grid and PJM's energy balancing market.3 Initial framing of this task and indicative results could be done with the assistance of energy experts at Rutgers, along with the stakeholder input the Board is currently gathering.

More detailed analysis, to support any actual storage procurement deployment, however, would best be done through regional dispatch simulation of an increasingly clean energy system, using electric system planning tools that accurately and precisely account for wind and solar availability, variability and costs across the broad, interconnected regional electric grid that includes New Jersey. NJCF has previously recommend the use of such tools in integrated energy planning for New Jersey, which would help inform both the state's Energy Master Plan and its various clean energy goals and policies.4

Such tools can identify VRE resources from within the state and across the region, which, in combination, provide the best fit to meet New Jersey's energy consumption patterns at the least cost, reducing the need for and cost of storage. Such tools should also include commercially addressable flexible load, which in some cases may be a far cheaper alternative than either new generation or energy storage. Such tools can also then identify storage needs and opportunities still needed, in terms of both the quantity of storage needed and the time frame within which the various storage types would need to perform.

With the best insights into the types and quantities of storage functions and services likely to be needed, the next step would be to identify which specific storage technologies, in what amounts, can best meet the energy storage needs identified in the above analysis. This will involve considerable detailed evaluation of the costs, benefits and risks of various storage technologies. As such, it would be done best by private sector investors and storage companies with specialized knowledge, who face concrete investment opportunities that create strong incentives to manage both cost and risk, rather than by a state agency or a disinterested technical analysis.5 This type of private storage investment could be incentivized, for example, by competitive procurement for the types and quantities of the various storage services identified in the first step. Periodically updating this planning and procurement process, with inputs to the planning process reflecting current commercial costs and performance capabilities of storage and other clean energy technologies, would result in a low-cost pathway towards an integrated clean energy portfolio for both the state and, increasingly for the entire region.

3. Additional storage benefits may be attained, beyond integration of high levels of VRE supply.

Energy storage also has the potential to create other benefits, beyond this critical role of helping to enable high levels of VRE energy production. These benefits include enhancing the ability of the distribution system to deliver high peak demand levels at lower cost than increasing the size and voltage ratings of distribution transformers and switch gear; enhancing resilience for facilities where uninterruptible power supplies (UPS) are important; and improving power quality where needed for sensitive electronics and processes.

The first of these – supporting high, localized peak electricity loads -- may be particularly important for reaching the GWRA decarbonization goals, since it may potentially support and accelerate the electrification of key emitting sectors such as transportation, the built environment, and various types of industrial processes. For example, high speed electric vehicle charging, without lengthy queuing, can create very high peak demands at popular charging facilities. Battery or other suitable storage devices at such facilities could potentially meet this demand with energy stored at times of lower use, avoiding or reducing the need for expensive capacity upgrades to the distribution system's delivery and safety equipment. If cost-effective, such storage would reduce the ratepayer impacts of such upgrades, while allowing electric vehicle charging services to avoid high distribution system demand charges. Further, by allowing the energy for such uses to be stored at times of maximum renewable energy production, such applications could dramatically increase the ability of a clean energy system to reliably balance high levels of VRE production, even as they are also decarbonizing a major energy end use.

Similarly, widespread adoption of battery systems at the household or business level for resilience benefits could, in parallel, support a more cost-effective approach to maintaining voltage levels and the volt-var balance on the distribution system, while also supporting greater penetration of distributed solar. Such “stacked benefits” are widely thought to be one potential way for a given investment in energy storage technologies to produce commercial and social benefits above and beyond any one purpose. Figure 4 in the Appendix illustrates how such distributed storage and other distributed energy resources (DERs) could be configured on the state’s low voltage electric distribution systems, several services and value streams they could provide, and key stakeholders for each service and deployment.

4. Distribution planning for batteries and other DERs to support the state’s clean energy goals.

The examples above suggest that New Jersey needs to consider how best to achieve such “stacked benefits” from storage located on the lower voltage distribution system, whether in front of or behind the meter. In the examples, some of these potential benefits accrue directly to customers (such as increased resilience and the lower maintenance and operating costs of electric vehicles), while some result from selling reliability and balancing services to the wholesale energy market, and still others come from avoiding higher cost upgrades to the regulated distribution utility’s distribution network. In addition, there can be broad social benefits, such as increased resilience at emergency services, new and growing business sectors in electrification and efficient flexible load, and rapid and globally replicable reductions in GHG emissions.

These considerations suggest another planning workstream needed to support the state’s clean energy goal – namely, distribution system planning, with the goal of identifying barriers and solutions to achieving the direct customer benefits, distribution system cost reductions, and broader societal benefits of behind the meter and distribution system located storage and other, related distributed energy resources (DERs).

Such a distribution planning process should be a part of, and closely coordinated with, the broader integrated planning process, for two reasons. First, the amount, type and location of such storage and other DERs are of central importance to, and will be dictated by, what is necessary for achieving the state’s clean energy goals at affordable cost levels. And second, to achieve this central goal, storage and other DERs must interact with, and produce benefits for, both the larger wholesale market and the local distribution system. Accordingly, as part of the overall integrated energy planning process, distribution planning should focus on identifying and improving the capabilities of the distribution system, and of the resources located on or behind it, to support and enhance the cost-effective achievement of the state’s clean energy and global warming response goals.

Coupling such distribution planning with competitive procurement and other market-based approaches to attracting private investment in storage and other DERs will help minimize ratepayer costs, allocate the risks of innovation to investors rather than ratepayers, and focus the utility on infrastructure, information and energy management systems needed to support effective deployment, operation and benefit stacking of storage and other DERs.

6. Answers to specific staff questions.

Several of the staff question refers to “renewable electric energy storage systems,” which the same language is used in the statute. It is not clear what the plain meaning of the statutory language is. Given that, it is important to note that in practice it would be extremely difficult to limit electric storage systems to storing renewable energy only. This is because a storage device that uses electricity from the interconnected electric grid as an input will store whatever mix of renewable and non-renewable energy is currently energizing the electric grid. Even an energy storage device that is co-located behind the meter with a renewable energy generating resource would frequently store non-renewable, grid-sourced electricity, unless it were operated so it only charges when, and to the extent that, the co-located renewable energy resource is generating more electricity that is being consumed behind that same meter. Such a requirement, however, would dramatically limit energy storage deployment and prevent many of the beneficial uses described above, which are very likely necessary to achieve the state’s clean energy and global warming response goals.

Another more feasible and relevant approach would be to ensure electric energy storage systems facilitate and store increasing amounts of renewable and clean energy. This approach seems more consistent with the state’s aggressive clean energy, renewable energy and global warming response goals. The planning and procurement recommendations above are based on achieving these goals in line with the Act’s focus on using competition where possible and minimizing ratepayer costs. Accordingly, this view of what is meant by “renewable electric energy storage” is implicit in NJCF’s answers to the following questions. [More info in the Appendix FJ]

Commenter, file name

[1] PSEG, 2019-03-20 - Energy Storage Comments

[2] CEG, CEG Comments re.. New Jersey Energy Storage Analysis - 3.20.19 (002)

[3] DER, COMMENTS FROM DIVERSIFIED ENERGY REGULATORY CONSULTING - ENERGY STORAGE ANALYSIS

[4] NJDRC - Comments NJDRC Re Energy Storage Analysis

[5] DRN - Direct Energy Comments to NJ Energy Storage Stakeholder Questions March 20, 2019 RLG Final

[6] OCE - Energy Storage Analysis - Request for Comments Name withheld by request

[7] VES - Energy Storage Analysis Comments VS, Environment NJ, SUN NJ

[8] OMNES - ENERGY STORAGE ANALYSIS_OMNES ENERGY RESPONSE TO NJBPU REQUEST FOR COMMENTS_March 19,2019

[9] INGER - Ingersoll Rand comments to NJ Energy Storage Analysis Request for Comments Final

[10] JCPL - JCPL Comments on Energy Storage Analysis_FILE

[11] NJCF - March 20 NJCF Energy Storage Analysis comments

[12] NJR - March 2019 Energy Storage Analysis Comments Final

[13] MSS - MSSIA comments re. New Jersey Energy Storage Analysis - LKR 3-20-19

[14] SP - NJ - Energy Storage Request for Comments FINAL 20190320

[15] RECO - NJ Energy Storage Analysis RECO comments FINAL03202019

[16] TESLA - NJBPU_Tesla_Energy_Storage_Analysis_Comments_FINAL

[17] POWED - Power Edison Comments 03202019

[18] SUN - Sunrun Responses - NJBPU Energy Storage Analysis 3.20.19

[19] SUNOWNER - Storage Comments 3.20.2019

APPENDIX C – Element 3: Supporting Materials

Electrochemical energy storage

Lithium-ion (Li-ion) non aqueous batteries

<u>Chemistries:</u>

A plethora of positive and negative materials have been developed since the inception of Li-ion batteries. While we are not going to delve into the details of each class of materials, it is worth noting the benefits and shortcomings on performance and cost of the different chemistries that have already been deployed for grid applications. Although graphite is currently the most commonly used negative electrode in Li-ion batteries, lithium titanate $Li_4Ti_5O_{12}$ (LTO) offers high power density and extended cycle life and also faster charging compared to competing chemistries. LTO is the only class of intercalation material capable of approaching or reaching the "zero-strain" intercalation materials that show very low volume change upon reaction with lithium during cycling. In addition, its higher potential improves safety by preventing Li-plating at the negative electrode during cycling at high rates enabling faster charging. However, it unfortunately significantly reduces energy density, and LTO increases costs. LTO-based Li-ion batteries are currently manufactured worldwide. Manufacturers include Altairnano and Xalt Energy in the US, Toshiba (SCiB™ series with $LiCoO_2$) in Japan, Kokam in South Korea, and Leclanché in Europe (Table C1). The first utility-scale 1 MW/0.25 MWh demonstration system built in Pennsylvania in 2008 by AES Energy Storage was based on LTO chemistry sourced from Altairnano ([77], Table C3). LTO has also been deployed in many installations worldwide over the years and varying in capacity. More recently, arrays of Toshiba SCiB™ batteries have been deployed in Japan in 2016 at the Minami-Soma and the Nishi-Sendai Substations where 40 MW / 40 MWh ([11], Table C2) and 40 MW / 20 MWh ([13], Table C2) energy storage systems have been commissioned in 2016. The 20 Ah Toshiba SCiB™ prismatic cells[1] are advertised to achieve 20,000 cycles under a 3C-rate which constitutes approximately a 4-factor increase over graphite-based cells with a typical cycle life of < 5,000 cycles at best.

[1] Toshiba. 2019. "The SCiBTM Rechargeable Battery." (Accessed May 5, 2019. https://www.scib.jp/en/about/index.htm).

Table C1: List of some of the main Li-ion cell manufacturers worldwide. [2]

Manufacturer		Chemistry	Packaging
JAPAN	GS YUASA	LMO, NCA, NMC, LFP, LCO	Prismatic
	HITACHI	LMO-NMC, NMC	Cylindrical, Prismatic
	SAYO-PANASONIC	NMC, LMO-NMC, LMO-NCA, LFP	Cylindrical, Prismatic
	TOSHIBA	LCO (LTO anode)	Prismatic
CHINA	BAK	LFP	Cylindrical, Prismatic, Pouch
	CALB	LFP	Pouch
	WINSTON BATTERY	LFP	Prismatic
	BYD	LFP	Prismatic
South KOREA	KOKAM	NMC, NMC-LTO, LCO	Pouch
	LG-CHEM	LMO, LFP, NMC	Pouch
	EIG LTD.	LFP, LMO-NMC	Pouch
	SAMSUNG	LCO, NMC, LMO-NMC, LFP	Cylindrical, Prismatic
	SK ENERGY	LMO	Pouch
USA	A123	LFP	Cylindrical, Pouch
	AESC	LMO, NMC, LMO-NMC, NCA	Pouch
	ENERDEL	NMC, LMO	Pouch
	JOHNSON CONTROLS	NMC, NCA	Cylindrical, Prismatic
	VALENCE TECH	LFP	Cylindrical
	XALT ENERGY	NMC, LTO	Pouch
EUROPE	LECLANCHE	NMC, LTO	Pouch
	HOPPECKE	LFP	Pouch
	VARTA AG.	LMO	Cylindrical, Prismatic, Pouch
	SAFT	LFP, NCA	Cylindrical,
	GAIA-LTC	LCO, NCA, LFP	Cylindrical

In terms of the positive electrode, $LiCoO_2$ (LCO) has been the dominant material in the past 25 years. However, its use has been reduced very significantly and is not utilized in most grid scale applications. The research community has been developing nickel-rich $LiNi_xMn_yCo_{1-x-y}O_2$ (NMC) lithium metal oxide materials to reduce the amount of cobalt. The NMC 111, 442 and 532 compounds, which correspond to the atomic ratios, except for the 111 that refer to 333 are commonly used chemistries in Li-ion batteries. These materials bring about a combination of benefits besides lower cost that include enhanced performance such as higher capacity, longer cycle life, and improved safety through higher thermal stability. NMC materials are commonly used in grid level applications as illustrated as Kokam's NMC-based batteries deployed in the 24 MW / 9 MWh Shin-Gimje Substation ([33], Table C2) and 16 MW / 6 MWh Shin-ChungJu Substation ([53], Table C3) energy storage systems commissioned in 2016 in Japan, and in the 30 MW / 11.4 MWh energy storage system at the Newman Power Station - Alinta Energy commissioned in Australia in 2018 ([25], Table C2).

The Ni-rich $LiNi_{0.8}Co_{0.15}Al_{0.05}O_2$ (NCA) also exhibits good properties including excellent energy density, but at a premium cost compared to NMC materials. Tesla, which relies heavily on the NCA chemistry for its electric cars, utilizes NCM-based cells for its stationary energy storage products, such as the Powerwall and the Powerpacks. NCA has been deployed in a 1.2 MW / 1 MWh system in Italy which has been operational since 2014. Its premium cost favors the use of NCM for large scale applications.

[2] Gonzalo Abad (ed.). 2016. *Power Electronics and Electric Drives for Traction Applications*. (John Wiley & Sons, Ltd.: 2016. Wiley Online Library. https://onlinelibrary.wiley.com/doi/book/10.1002/9781118954454?cookieSet=1).

In contrast to the layered 2D structures of the NMC and NCA materials, $LiFePO_4$ (LFP) is a 1D-structured material that reacts with lithium at lower potential and therefore provides much lower energy density. Yet its good power capability, good thermal stability and thereby improved safety, but mostly its reported enhanced lifetime, combined with lower cost, enabled its penetration into larger scale market applications such as grid.[3] Both 31.5 MW/ 12.2 MWh Beech Ridge Energy Storage (Rupert, W. VA) ([21], Table C2) and 31.5 MW/ 12.2 MWh Grand Ridge Energy Storage (Marseille, Ill.) ([22], Table C2) developed by Invernergy LLC and commissioned in 2015 utilize BYD America's Containerized Energy Storage Systems that feature its proprietary LFP battery chemistry. Several LFP-based systems have been deployed in China in a lower power range of 1 to 10 MW but of longer durations up to 36 hours. The goal of the BYD 1 MW / 36 MWh project was to demonstrate a stable solution for transferring vast amounts of renewable electricity safely to the grid on an unprecedented scale with battery energy storage arrays larger than a football field. A combination of chemistries can also be used in order to achieve a balance between the positive attributes of the different components. Kokam's NANO cells based on LTO NMC/LFP positive electrodes and LTO negative electrode were initially designed for defense and aerospace applications. The LTO and LFP provide good safety, cycling, and life robustness, as well as good power capability, while NMC provides higher capacity. As such, Kokam's NANO positive features provide flexibility in market application, although it comes at a premium due to the LTO electrodes. Kokam's NANO technology was deployed in combination with NMC in the 36 MW / 13 MWh Non-Gong Substation battery storage system commissioned in 2016 in Japan ([15], Table C2).

Finally, the spinel $LiMn_2O_4$ (LMO) is another well-established commercial battery material used for positive electrodes. LMO exhibits excellent power capability, excellent thermal stability, and, most importantly, low cost. However, LMO shows lower energy performance and only moderate cycle life that may be insufficient for some applications. While it has been used early on in a 1 MW / 1 MWh demonstration project at the Technology Solutions for Wind Integration - Center For Commercialization of Electric Technology in Lubbock, Texas commissioned in 2013 ([76], Table C3), LMO remains especially attractive in the form of LMO-based blends, such as NMC/LMO, to achieve a suitable balance between technical performance and cost.[4] In short, various Li-ion chemistries have already reached the grid market: NMC is the most used for grid application as it is the most versatile positive electrode technology with the best overall performance and cost, while NCA although of good performance, comes at a premium compared to NMC. LFP and LTO technologies offer power and cycle life benefits but at lower energy density, and, in terms of costs, LFP provides relief while LTO comes at a premium.

[3] U.S. Department of Energy. 2013. (*Grid Energy Storage 2013.* December 2013. https://www.energy.gov/sites/prod/files/2014/09/f18/Grid%20Energy%20Storage%20De cember%202013.pdf).
[4] Christophe Pillot. 2017. "The Rechargeable Battery Market and Main Trends 2016-2025." (Avicienne. PowerPoint presented at 33rd International Battery Seminar and Exhibit. Fort Lauderdale, FL. March 20, 2017. http://cii-resource.com/cet/FBC-TUT8/Presentations/Pillot_Christophe.pdf).

Table C2: List of Li-ion battery storage systems of 20 to 300 MW power rating already installed, contracted or under construction.[5] The systems highlighted whose commissioning years are highlighted in yellow are under contract or in construction. Systems located in the United States are highlighted in blue, New Jersey in darker blue. Power systems with duration times in the 15 to 50-minute range are highlighted in green, mid-power systems with durations in the 1- 2 hour range are highlighted in orange, and energy systems at four hours are highlighted dark red.

Ref.	Location	Project Name	Paired Grid Resource	Commiss.	Siting	Business Model	Tech	Power	Capacity	Duration	Life time	Footprint		Energy Storage Tech.
#				Year		Owner	Chem.	MW	MWh	h:mm	Years	m2/MW	m2/MWh	System / Battery
1	United States, CA, Moss Landing	Vistra Moss Landing Energy Storage Project	-	2020		Utility	Li-Ion	300	1200	4:00	20			Dynegy Marketing and Trade LLC
2	United States, CA, Moss Landing	Moss Landing Energy Storage Project		2020		Utility	Li-Ion	182.5	730	4:00	20			Tesla / Panasonic
3	United States, CA, Long Beach	Alamitos Energy Storage Array		2021		Third-Party	Li-Ion	100	400	4:00	20			Fluence
4	Australia, SA, Morgan	Riverland Solar Storage Project - Lyon Group	330 MW PV	N/A			Li-Ion	100	400	4:00				
5	Australia, SA, Roxby Downs	Kingfisher Project	120 MW PV	2020		Third-Party	Li-Ion	100	200	2:00				AES Energy Storage
6	Australia, SA, Horsndale	Hornsdale Power Reserve	315 MW Wind	2017		Utility	Li-Ion	100	129	1:17	15	100	78	Tesla / Samsung
7	United States, CA, Morgan Hill	Hummingbird Energy Storage Project		2020		Utility	Li-Ion	75	300	4:00	15			esVolta
8	United Kingdom	Roosecote Energy Storage		2018		Customer	Li-Ion	49	24.5	0:30				Younicos Inc
9	Germany	Jardelund "EnspireMe"		2016		Customer	Li-Ion	48	50	1:02	15	63	60	NEC Energy Solutions
10	South Korea	Gyeongsan Substation		2016		Utility	Li-Ion	48	12	0:15				Woojin Industrial Systems / LG Chem Ldt.
11	Japan	Minami-Soma Substation	-	2016		Utility	Li-Ion (LCO/LTO)	40	40	1:00				Toshiba Corporation / Toshiba SCiB™ batteries
12	United Kingdom	Glassenbury Battery Storage Project		2017		Utility	Li-Ion	40	28	0:41				
13	Japan	Nishi-Sendai Substation	-	2016		Utility	Li-Ion (LCO/LTO)	40	20	0:30				Toshiba Corporation / Toshiba SCiB™ batteries
14	United States, TX, Goldsmith	Notrees Battery Storage Project (initially Pb-acid, Li-ion updgrate in 2016)	153 MW Wind	2013	Transmission	Utility	Li-Ion (2016 upgrade)	36	24	0:40				Xtreme Power Pb-acid / Samsung Ldt Li-ion
15	South Korea	Non-Gong Substation	-	2016		Utility	Li-Ion (NMC) + (NANO tech)	36	13	0:22				Kokam
16	United States, CA, Orange County	Convergent- SCE		2020		Utility	Li-Ion	35	140	4:00	15			Convergent Energy + Power (Energy storage asset developer)
17	United Kingdom	Foresight Group Port of Tyne 35 MW ESS - RES (UK)		initially 2018		Customer	Li-Ion	35	23	0:40				RES Ldt. (UK) (Renewable Energy Systems)
18	United States, CA, El Centro	Imperial Irrigation District (IID) BESS - GE	solar/geothermal /biomass/ hydro	2016	Transmission	Customer	Li-Ion	33	20	0:36	18-20	74	122	GE / Samsung SDI Ldt.
19	South Korea	Ul San Substation		2017		Utility	Li-Ion	32	12	0:23				Samsung SDI Ldt.
20	United States, W. VA, Elkins	AES Laurel Mountain Energy Storage	98 MW Wind	2011	Transmission	Third-Party	Li-Ion (LFP)	32	8	0:15				AES Energy storage / A123 Systems
21	United States, W. VA, Rupert	Beech Ridge Wind Storage	100.5 MW Wind	2015		Third-Party	Li-Ion (LFP)	31.5	12.2	0:23				BYD
22	United States, IL, Marseilles	Grand Ridge Energy Storage	210 MW Wind + 20 MW PV	2015		Third-Party	Li-Ion (LFP)	31.5	12.2	0:23				BYD
23	United States, CA, Escondito	Escondido Substation	Escondido Substation	2017	Primary Distribution	Utility	Li-Ion	30	120	4:00	10			AES Energy storage / Advancion® batteries
24	Australia, VIC, Ballarat	Ballarat Area Terminal Station (BATS)		2018		Customer	Li-Ion	30	30	1:00				Fluence
25	Australia	Newman Power Station - Alinta Energy	178 MW Gas Fired Plant	2018		Third-Party	Li-Ion (NMC)	30	11.4	0:23		70	184	ABB / Kokam
26	Australia, SA, Yorketown	Dalrymple		2018		Third-Party	Li-Ion	30	8	0:16	12			ABB / Samsung SDI Ldt.
27	South Korea	West-Ansung (Seo-Anseong) Substation		2015		Utility	Li-Ion	28	7	0:15				LTO Kokam (16MW/5MWh) + LG-Chem (12MW)
28	Australia, SA, Barmera	Lake Bonney Energy Storage	278.9 MW Wind	2019		Third-Party		25	52	2:05	10-15			Tesla
29	Australia, VIC, Kerang	Gannawarra Energy Storage	60 MW PV	2018		Customer	Li-Ion	25	50	2:00				Tesla
30	United States, AK, Anchorage	Anchorage Energy Storage		2016	Transmission	Utility		25	14	0:34				
31	United Kingdom	Enel S.p.A. Tynemouth		2018		Customer	Li-Ion	25	12.5	0:30				RES
32	South Korea	Shin-Yongin Substation		2014		Utility	Li-Ion	24	12	0:30				Samsung SDI Ldt.
33	South Korea	Shin-Gimje Substation		2016		Utility	Li-Ion (NMC)	24	9	0:23				Kokam
34	South Korea	Uiryeong Substation		2016		Utility	Li-Ion	24	6	0:15				LG CNS
35	South Korea	Shin-GyeRyong Substation		2016		Utility	Li-Ion	24	6	0:15				LG Chem Ltd.
36	United Kingdom	Pen y Cymoedd Storage	228 MW Wind (onshore)	2018			Li-Ion	22	16	0:45				Used BMW i3 batteries (Samsung SDI Ldt.)
37	Australia, QLD, Lakeland	Cape York 20 MW/80 MWh- 55 MW Solar PV- Lyon Group	55 MW PV	2019	Transmission	Third-Party	Li-Ion	20	80	4:00				AES Energy Storage
38	United States, CA, Pomona	Pomona Energy Storage Facility	44.5 MW Gas Fired Plant	2016	Transmission	Third-Party	Li-Ion	20	80	4:00				Altgas / Samsung SDI Ldt.
39	United States, CA, Ontario	Southern California Edison Mira Loma Substation		2017		Utility	Li-Ion	20	80	4:00				Tesla
40	Australia, VIC	Bulgana Green Energy Hub Victoria	194 MW Wind	2019		Third-Party	Li-Ion	20	34	1:42	25			Tesla
41	United Kingdom	Broxburn -RES		2018		Third-Party	Li-Ion	20	22	1:06	15			RES / Samsung SDI Ldt.
42	United States, IN, Indianapolis	IPL Advancion Energy Storage Array - Harding St. Thermal Generation Plant	Thermal Power Plant	2016	Transmission	Utility	Li-Ion	20	20	1:00	10			Samsung SDI Ldt.
43	United States, CA, Beacon	Beacon Battery Storage	570 MW PV + 490 MW PV expansion	2018		Utility	Li-Ion	20	10	0:30				Doosan Grid Tech
44	United States, IL, DeKalb	Lee DeKalb Energy Storage	217.5 MW Wind	2015		Third-Party	Li-Ion	20	10	0:30				LG Chem Ltd.
45	United States, IL, Kern County	Marengo Project		2018		Third-Party	Li-Ion	20	10	0:30	10			Leclanché SA
46	Chile	Cochrane Thermal Power Station Storage System	532 MW Coal-Hybrid Power Plant	2017	Primary Distribution	Third-Party	Li-Ion	20	6.75	0:20				Fluence / Mitsubishi Corporation & GS Yuasa
47	Chile	AES Angamos Storage Array	544 MW Thermal Power Plant	2011	Transmission	Third-Party	Li-Ion	20	5	0:15				ABB / A123 Systems
			Contracted, Under construction							< 1h	1-2hrs	4h		

[5] U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).

Table C3: List of Li-ion battery storage systems of 1 to 19.8 MW power rating already installed, contracted or under construction.[6] The systems highlighted whose commissioning years are highlighted in yellow are under contract or in construction. Systems located in the United States are highlighted in blue, New Jersey in darker blue. Power systems with duration times in the 15 to 50-minute range are highlighted in green, mid-power systems with durations in the 1- 2 hour range are highlighted in orange, and energy systems at four hours are highlighted dark red.

Ref.	Location	Project Name	Paired Grid Resource	Commiss.	Siting	Business Model	Tech	Power	Capacity	Duration	Life time	Footprint		Energy Storage Tech.
#				Year		Owner	Type	MW	MWh	h:mm	Years	m2/MW	m2/MWh	System / Battery
48	United States, IL, McHenry County	McHenry Battery Storage Project		2015	Primary Distribution	Third-Party	Li-Ion	19.8	7.8	0:24				EDF / BYD
49	United States, IL Joliet	Jake Energy Storage		2015		Third-Party	Li-Ion (LFP)	19.8	7.8	0:24	10			RES / BYD America
50	United States, IL, West Chicago	Elwood Energy Storage Center		2015		Third-Party	Li-Ion (LFP)	19.8	7.8	0:24	10			
51	United States, PA, Somerset County	Meyersdale Energy Storage		2015		Third-Party	Li-Ion	18	9	0:30				NextEra
52	United States, ME, Yarmouth	Wyman Station	822 MW Oil-fired Plant	2016			Li-Ion	16.2	8.1	0:30				NextEra
53	South Korea	Shin-ChungJu Substation		2016		Utility	Li-Ion (NMC)	16	6	0:23				Kokam
54	Germany	Lünen Energy Storage	507 MW Co-generation Plant	2016		Utility	Li-Ion	15	23	1:32		111	72	Steag Energy Services / LG Chem Ltd.
55	Germany	Walsum Energy Storage	560 MW Co-generation Plant	2016	Transmission	Utility	Li-Ion	15	23	1:32				
56	Germany	Bexbach Energy Storage	780 MW Coal Power Plant	2016	Transmission	Utility	Li-Ion	15	23	1:32				
57	Germany	Volklingen-Fenne Energy Storage	466 MW Co-generation Plant	2016	Transmission	Utility	Li-Ion	15	23	1:32				
58	Germany	Weiher Energy Storage	724 MW Co-generation Plant	2016	Transmission	Utility	Li-Ion	15	23	1:32				
59	Germany	Herne Energy Storage	960 MW Co-generation Plant	2016	Transmission	Utility	Li-Ion	15	23	1:32				
60	Germany	Daimler AG 15 MWh		2016		Customer	Li-Ion	15	15	1:00				Daimler AG's subsidiary ACCUmotive & enercity / Daimeler's EV battery packs
61	Germany	WEMAG Schwerin Battery Park - Younicos		2014	Secondary Distribution	Utility	Li-Ion	15	15	1:00	20			Samsung SDI Ldt.
62	United States, HI, Kaua'i	Kaua'i Dispatchable Solar Storage	12 MW PV	2017		Third-Party	Li-Ion	13	52	4:00	20			Tesla
63	Germany	Daimler 2nd Life Storage - The Mobility House (Lünen (2))		2016		Third-Party	Li-Ion	13	12.8	1:00	10			
64	South Korea	GS E&R-LG Chem (Yeongyang)		2016		Customer	Li-Ion	12.5	24	1:55				Kokam
65	Chile	Los Andes Substation Battery Energy Storage		2009	Transmission	Third-Party	Li-Ion	12	4	0:20				A123 Systems
66	United States, HI, Kula	Auwahi Wind Farm Storage	21 MW Wind	2012		Third-Party	Li-Ion	11	4.4	0:24	20			A123 systems (NEC Energy Solutions)
67	United States, PA, Somerset County	Green Mountain Energy Storage - NextEra		2015		Third-Party	Li-Ion	10.4	10.4	1:00				NextEra
68	Germany	Feldheim Regional Regulating Power Station	72 MW Wind	2015		Third-Party	Li-Ion	10	10	1:00				LG Chem Ltd.
69	United States, CA, Techapi	Tehachapi Wind Energy Storage Project - Southern California Edison	4500 MW Wind	2014	Transmission	Utility	Li-Ion	8	32	4:00				ABB/ LG Chem Ltd.
70	United States, CA, El Cajon	El Cajon Storage		2017	Primary Distribution	Utility	Li-Ion	7.5	30	4:00				AES Energy Storage with Advancion® battery
71	United States, HI, Anahola	Kauai Island Utility Cooperative & REC Solar	12 MW PV	2015	Primary Distribution	Utility	Li-Ion (NCA)	6	4.63	0:46				ABB/SAFT
72	Autralia, WA, Kalbarri	Kalbarri Microgrid Energy Storage	PV, Wind	2019		Utility	Li-Ion	5	2	0:24				Energy Made Clean (EMC)/LendLease Services
73	United States, WA, Glacier	Glacier Battery Storage		2016	Transmission	Utility	Li-Ion	2	4.4	2:12				RES America
74	United States, NJ,Atlantic City	ACUA Treatment Plant - Viridity Energy	7.5 MW Wind + 500 kW PV	2018		Customer	Li-Ion	1	1.05	1:05				Johnson Controls
75	United States, NJ, Pennington	Hopewell Valley High School *Pilot program*	876 kWPV (rooftop)	2015		Utility	Li-Ion	1	0.5	0:30				
76	United States, TX, Luccock	Center For Commercialization of Electric Technology (CCET)		2013	Transmission	Utility	Li-Ion (LMO)	1	1	1:00				
77	United States, PA, Lyons	Altairnano-PJM Lyons Li-ion Battery Ancillary Services Demo		2008		Third-Party-Owned	Li-Ion (LTO)	1	0.25	0:15	20			AES Energy Storage / Altair Nanotechnologies Inc.
			Contracted, Under construction							< 1h	1-2hrs	4h		

[6] U.S. DOE Global Energy Storage Database. (Accessed February 4, 2019. https://www.energystorageexchange.org/).

APPENDIX D – Additional Benefit-Cost Sensitivities and Capital Costs

Table D1 through Table D5 present the results of additional cost-benefit analyses for alternative battery parameters in facility resiliency use cases. All battery sizes are scaled to 1 MW based on independent battery installations of the reported size – e.g., 0.25 MW (x4) refers to four independent 250 kW batteries. The following configurations were modeled:

- Table D1 Resiliency Case: Energy Storage with PV; 0.25 MW (x4), 4-Hour Li-ion Battery (1 MW total installed); mid-range CapEx, 2020
- Table D2: Resiliency Case: Standalone ES; 0.5 MW (x2), 4-Hour Li-ion Battery (1 MW total installed); mid-range CapEx, 2020
- Table D3: Resiliency Case: Energy Storage with PV; 0.5 MW (x2), 4-Hour Li-ion Battery (1 MW total installed); mid-range CapEx, 2020
- Table D4: Resiliency Case: Standalone Energy Storage, 1 MW, 1 Hour Li-ion Battery; mid-range CapEx, 2020
- Table D5: Resiliency Case: Energy Storage with PV, 1 MW, 1 Hour Li-ion Battery; mid-range CapEx, 2020

Table D6 provides the range of estimated Li-ion capital costs (low, mid-range, high) in 2018 and their levels in 2020, 2025 and 2030 based on low, moderate and high cost de-escalation trajectories. The mid-range estimates in 2020 under the moderate de-escalation scenario underlie the base case analyses presented in the body of the report.

A literature review conducted to inform the cost-benefit analysis follows Table D6.

Table D1 Resiliency Case: Energy Storage with PV; 0.25 MW (x4), 4-Hour Li-ion Battery (1 MW total installed); mid-range CapEx, 2020

Battery Size:	0.25 MW (x4)	
PV Size:	Serves 80% of Peak Load	
Battery Duration:	4 Hours	
Year:	2020	
ITC:	26%	Applies only where annual share of PV charging is 75% or greater and is pro-rated to % of PV charging.
Depreciation:	Varies	5-year MACRS where ITC applies, 7-year MACRS otherwise.
Cost De-Escalation Scenario:	Moderate	
Discount Rate:	10%	
Annual Operating Costs:	$10/kW/yr.	
Blended Tax Rate:	28.1%	
Availability	96.0%	
Efficiency:	85.0%	

Facility:	Hospital			Apartment Complex			Hotel			Office			Secondary School			Supermarket		
CapEx Level:	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**
PV Size	1.6	1.6	1.6	0.7	0.7	0.7												
% PV Charging	81%	81%	81%	85%	85%	85%												
Capex/kW	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640	$2,641	$2,642	$2,643	$2,644	$2,645	$2,646	$2,647	$2,648	$2,649	$2,650	$2,651	$2,652
Lifetime Adjusted Costs (CapEx + OpEx)*	$1,103,267	$1,503,649	$1,904,626	$1,072,673	$1,465,673	$1,859,257	$1,091,206	$1,482,009	$1,873,393	$1,099,742	$1,508,831	$1,918,527	$1,304,883	$1,840,602	$2,377,118	$1,087,220	$1,482,636	$1,878,640
Lifetime Benefits, adjusted for availability	$1,388,562	$1,388,562	$1,388,562	$1,332,660	$1,332,660	$1,332,660	$1,410,411	$1,410,411	$1,410,411	$1,319,223	$1,319,223	$1,319,223	$1,186,417	$1,186,417	$1,186,417	$1,366,439	$1,366,439	$1,366,439
BCR (financial)	1.26	0.92	0.73	1.24	0.91	0.72	1.29	0.95	0.75	1.20	0.87	0.69	0.91	0.64	0.50	1.26	0.92	0.73
NPV (financial)	$285,295	-$115,086	-$516,063	$259,987	-$133,013	-$526,597	$319,205	-$71,598	-$462,982	$219,481	-$189,607	-$599,304	-$118,466	-$654,185	-$1,190,700	$279,219	-$116,197	-$512,201
Value of Avoided Outages ($)	$610,494	$610,494	$610,494	$3,161	$3,161	$3,161	$159,840	$159,840	$159,840	$119,234	$119,234	$119,234	$32,881	$32,881	$32,881	$477,155	$477,155	$477,155
NPV net Value of Avoided Outages and Emissions	$895,789	$495,408	$94,431	$263,148	-$129,852	-$523,436	$479,045	$88,243	-$303,142	$338,714	-$70,374	-$480,071	-$85,585	-$621,304	-$1,157,820	$756,373	$360,957	-$35,047

*Lifetime adjusted costs vary across facilities due to varying levels of energy cost and demand charge savings and their associated tax implications.

Table D2: Resiliency Case: Standalone ES; 0.5 MW (x2), 4-Hour Li-ion Battery (1 MW total installed); mid-range CapEx, 2020

Battery Size:	0.5 MW (x2)	
PV Size:	No PV	
Battery Duration:	4 Hours	
Year:	2020	
ITC:	N/A	ITC does not apply where there is no associated PV
Depreciation:	7-Year MACRS	
Cost De-Escalation Scenario:	Moderate	
Discount Rate:	10%	
Annual Operating Costs:	$10/kW/yr	
Blended Tax Rate:	28.1%	
Availability	96.0%	
Efficiency:	85.0%	

Facility:	**Hospital**			**Apartment Complex**			**Hotel**			**Office**			**Secondary School**			**Supermarket**		
CapEx Level:	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**
Capex/kW	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640
Lifetime Adjusted Costs (CapEx + OpEx)*	$1,084,286	$1,620,005	$2,156,521	$1,128,765	$1,664,484	$2,201,000	$1,182,360	$1,718,079	$2,254,595	$1,101,582	$1,637,300	$2,173,816	$1,104,560	$1,640,279	$2,176,795	$1,096,472	$1,632,191	$2,168,707
Lifetime Benefits, adjusted for availability	$433,044	$433,044	$433,044	$584,947	$584,947	$584,947	$767,982	$767,982	$767,982	$492,111	$492,111	$492,111	$502,284	$502,284	$502,284	$474,662	$474,662	$474,662
BCR (financial)	0.40	0.27	0.20	0.52	0.35	0.27	0.65	0.45	0.34	0.45	0.30	0.23	0.45	0.31	0.23	0.43	0.29	0.22
NPV (financial)	-$651,242	-$1,186,960	-$1,723,476	-$543,818	-$1,079,537	-$1,616,053	-$414,378	-$950,097	-$1,486,613	-$609,471	-$1,145,189	-$1,681,705	-$602,277	-$1,137,995	-$1,674,511	-$621,810	-$1,157,529	-$1,694,045
Value of Avoided Outages ($)	$510,857	$510,857	$510,857	$1,873	$1,873	$1,873	$92,089	$92,089	$92,089	$131,432	$131,432	$131,432	$31,961	$31,961	$31,961	$545,141	$545,141	$545,141
Net Avoided Emissions ($)**	-$18,372	-$18,372	-$18,372	-$15,767	-$15,767	-$15,767	-$20,197	-$20,197	-$20,197	-$16,139	-$16,139	-$16,139	-$14,108	-$14,108	-$14,108	-$17,360	-$17,360	-$17,360
NPV net Value of Avoided Outages and Emissions	-$158,756	-$694,475	-$1,230,991	-$557,711	-$1,093,430	-$1,629,946	-$342,486	-$878,205	-$1,414,721	-$494,178	-$1,029,897	-$1,566,412	-$584,424	-$1,120,143	-$1,656,659	-$94,029	-$629,748	-$1,166,264

*Lifetime adjusted costs vary across facilities due to varying levels of energy cost and demand charge savings and their associated tax implications.

** Avoided emissions include CO_2, SO_2 and NO_2. Negative dollar amounts indicate net increases in emissions.

Table D3: Resiliency Case: Energy Storage with PV; 0.5 MW (x2), 4-Hour Li-ion Battery (1 MW total installed); mid-range CapEx, 2020

Battery Size:	0.5 MW (x2)	
PV Size:	Serves 80% of Peak Load	
Battery Duration:	4 Hours	
Year:	2020	
ITC:	26%	Applies only where annual share of PV charging is 75% or greater and is pro-rated to % of PV charging.
Depreciation:	Varies	5-year MACRS where ITC applies, 7-year MACRS otherwise.
Cost De-Escalation Scenario:	Moderate	
Discount Rate:	10%	
Annual Operating Costs:	$10/kW/yr.	
Blended Tax Rate:	28.1%	
Availability	96.0%	
Efficiency:	85.0%	

Facility:	**Hospital**			**Apartment Complex**			**Hotel**			**Office**			**Secondary School**			**Supermarket**		
CapEx Level:	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**
PV Size	1.6	1.6	1.6	0.7	0.7	0.7	1.2	1.2	1.2	1.3	1.3	1.3	0.8	0.8	0.8	1.5	1.5	1.5
% PV Charging	81%	81%	81%	85%	85%	85%	87%	87%	87%	75%	75%	75%	68%	68%	68%	84%	84%	84%
Capex/kW	$1,295	$1,967	$2,640	$1,295	$1,967	$2,640	$2,641	$2,642	$2,643	$2,644	$2,645	$2,646	$2,647	$2,648	$2,649	$2,650	$2,651	$2,652
Lifetime Adjusted Costs (CapEx + OpEx)*	$1,084,735	$1,491,858	$1,899,587	$1,015,663	$1,406,689	$1,798,297	$1,062,534	$1,455,566	$1,849,182	$1,310,692	$1,846,410	$2,382,926	$1,217,625	$1,753,344	$2,289,860	$1,059,306	$1,458,254	$1,857,796
Lifetime Benefits, adjusted for availability	$1,280,902	$1,280,902	$1,280,902	$1,150,949	$1,150,949	$1,150,949	$1,297,819	$1,297,819	$1,297,819	$1,206,255	$1,206,255	$1,206,255	$888,418	$888,418	$888,418	$1,247,862	$1,247,862	$1,247,862
BCR (financial)	1.18	0.86	0.67	1.13	0.82	0.64	1.22	0.89	0.70	0.92	0.65	0.51	0.73	0.51	0.39	1.18	0.86	0.67
NPV (financial)	$196,167	-$210,957	-$618,686	$135,286	-$255,740	-$647,348	$235,285	-$157,747	-$551,363	-$104,437	-$640,156	-$1,176,672	-$329,207	-$864,926	-$1,401,442	$188,556	-$210,392	-$609,934
Value of Avoided Outages ($)	$305,247	$305,247	$305,247	$1,580	$1,580	$1,580	$79,920	$79,920	$79,920	$59,617	$59,617	$59,617	$16,440	$16,440	$16,440	$238,577	$238,577	$238,577
NPV net Value of Avoided Outages and Emissior	$501,414	$94,291	-$313,439	$136,866	-$254,160	-$645,767	$315,206	-$77,826	-$471,443	-$44,820	-$580,539	-$1,117,055	-$312,767	-$848,486	-$1,385,002	$427,133	$28,185	-$371,357

*Lifetime adjusted costs vary across facilities due to varying levels of energy cost and demand charge savings and their associated tax implications.

Table D4: Resiliency Case: Standalone Energy Storage, 1 MW, 1 Hour Li-ion Battery; mid-range CapEx, 2020

Battery Size:	1 MW	
PV Size:	No PV	
Battery Duration:	1 Hour	
Year:	2020	
ITC:	N/A	ITC does not apply where there is no associated PV
Depreciation:	7-Year MACRS	
Cost De-Escalation Scenario:	Moderate	
Discount Rate:	10%	
Annual Operating Costs:	$10/kW/yr	
Blended Tax Rate:	28.1%	
Availability	96.0%	
Efficiency:	85.0%	

Facility:	**Hospital**			**Apartment Complex**			**Hotel**			**Office**			**Secondary School**			**Supermarket**		
CapEx Level:	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**	**Low**	**Mid-Range**	**High**
Capex/kW	$512	$852	$1,192	$512	$852	$1,192	$512	$852	$1,192	$512	$852	$1,192	$512	$852	$1,192	$512	$852	$1,192
Lifetime Adjusted Costs (CapEx + OpEx)*	$374,065	$645,313	$916,560	$396,310	$667,558	$938,806	$418,842	$690,089	$961,337	$381,080	$652,328	$923,575	$382,071	$653,319	$924,566	$380,088	$651,336	$922,584
Lifetime Benefits, adjusted for availability	$139,661	$139,661	$139,661	$215,633	$215,633	$215,633	$292,581	$292,581	$292,581	$163,619	$163,619	$163,619	$167,003	$167,003	$167,003	$160,232	$160,232	$160,232
BCR (financial)	0.37	0.22	0.15	0.54	0.32	0.23	0.70	0.42	0.30	0.43	0.25	0.18	0.44	0.26	0.18	0.42	0.25	0.17
NPV (financial)	-$234,404	-$505,651	-$776,899	-$180,677	-$451,925	-$723,173	-$126,261	-$397,508	-$668,756	-$217,461	-$488,709	-$759,957	-$215,068	-$486,315	-$757,563	-$219,856	-$491,104	-$762,351
Value of Avoided Outages ($)	$344,432	$344,432	$344,432	$937	$937	$937	$47,246	$47,246	$47,246	$85,313	$85,313	$85,313	$16,906	$16,906	$16,906	$327,891	$327,891	$327,891
Net Avoided Emissions ($)**	-$4,897	-$4,897	-$4,897	-$5,168	-$5,168	-$5,168	-$5,970	-$5,970	-$5,970	-$4,257	-$4,257	-$4,257	-$4,161	-$4,161	-$4,161	-$4,677	-$4,677	-$4,677
NPV net Value of Avoided Outages and Emissior	$105,132	-$166,116	-$437,364	-$184,908	-$456,156	-$727,404	-$84,984	-$356,232	-$627,480	-$136,406	-$407,654	-$678,901	-$202,323	-$473,570	-$744,818	$103,358	-$167,890	-$439,137

*Lifetime adjusted costs vary across facilities due to varying levels of energy cost and demand charge savings and their associated tax implications.

** Avoided emissions include CO_2, SO_2 and NO_2. Negative dollar amounts indicate net increases in emissions.

Table D5: Resiliency Case: Energy Storage with PV, 1 MW, 1 Hour Li-ion Battery; mid-range CapEx, 2020

Battery Size:	1 MW	
PV Size:	Serves 80% of Peak Load	
Battery Duration:	1 Hour	
Year:	2020	
ITC:	26%	Applies only where annual share of PV charging is 75% or greater and is pro-rated to % of PV charging.
Depreciation:	Varies	5-year MACRS where ITC applies, 7-year MACRS otherwise.
Cost De-Escalation Scenario:	Moderate	
Discount Rate:	10%	
Annual Operating Costs:	$10/kW/yr.	
Blended Tax Rate:	28.1%	
Availability	96.0%	
Efficiency:	85.0%	

Facility:	Hospital			Apartment Complex			Hotel			Office			Secondary School			Supermarket		
CapEx Level:	Low	Mid-Range	High	Low	Mid-Range	High	Low	Mid-Range	High	Low	Mid-Range	High	Low	Mid-Range	High	Low	Mid-Range	High
PV Size	1.6	1.6	1.6	0.7	0.7	0.7	1.2	1.2	1.2	1.3	1.3	1.3	0.8	0.8	0.8	1.5	1.5	1.5
% PV Charging	68%	68%	68%	84%	84%	84%	81%	81%	81%	63%	63%	63%	65%	65%	65%	0.7562544	0.7562544	0.7562544
Capex/kW	$512	$852	$1,192	$512	$852	$1,192	$512	$852	$1,192	$512	$852	$1,192	$512	$852	$1,192	$512	$852	$1,192
Lifetime Adjusted Costs (CapEx + OpEx)*	$469,310	$740,558	$1,011,805	$337,573	$537,844	$738,115	$351,611	$554,020	$756,430	$493,634	$764,882	$1,036,130	$439,757	$711,005	$982,252	$366,755	$573,416	$780,077
Lifetime Benefits, adjusted for availability	$464,938	$464,938	$464,938	$379,694	$379,694	$379,694	$416,646	$416,646	$416,646	$548,010	$548,010	$548,010	$364,010	$364,010	$364,010	$446,522	$446,522	$446,522
BCR (financial)	0.99	0.63	0.46	1.12	0.71	0.51	1.18	0.75	0.55	1.11	0.72	0.53	0.83	0.51	0.37	1.22	0.78	0.57
NPV (financial)	-$4,372	-$275,620	-$546,867	$42,121	-$158,150	-$358,421	$65,035	-$137,375	-$339,784	$54,375	-$216,873	-$488,120	-$75,747	-$346,995	-$618,242	$79,767	-$126,894	-$333,556
Value of Avoided Outages ($)	$183,904	$183,904	$183,904	$853	$853	$853	$46,523	$46,523	$46,523	$37,787	$37,787	$37,787	$9,271	$9,271	$9,271	$153,367	$153,367	$153,367
NPV net Value of Avoided Outages and Emissior	$179,532	-$91,716	-$362,963	$42,973	-$157,298	-$357,568	$111,557	-$90,852	-$293,262	$92,163	-$179,085	-$450,333	-$66,476	-$337,724	-$608,972	$233,133	$26,472	-$180,189

*Lifetime adjusted costs vary across facilities due to varying levels of energy cost and demand charge savings and their associated tax implications.

Table D6: Li-ion Capital Costs and Projections

LITHIUM ION, $/kW																
COST DE-ESCALATION RATE			**2018**				**2020**				**2025**				**2030**	
LOW		**4-hour**	**1-hour**	**0.5-hour**		**4-hour**	**1-hour**	**0.5-hour**		**4-hour**	**1-hour**	**0.5-hour**		**4-hour**	**1-hour**	**0.5-hour**
	Low	1,520	601	448	**Low**	1,402	554	413	**Low**	1,174	464	346	**Low**	1,035	409	305
	Mid-Range	2,310	1,001	802	**Mid-Range**	2,131	923	740	**Mid-Range**	1,785	773	620	**Mid-Range**	1,573	681	546
	High	3,100	1,400	1,156	**High**	2,860	1,291	1,066	**High**	2,395	1,082	893	**High**	2,111	953	787
			2018				**2020**				**2025**				**2030**	
MODERATE		**4-hour**	**1-hour**	**0.5-hour**		**4-hour**	**1-hour**	**0.5-hour**		**4-hour**	**1-hour**	**0.5-hour**		**4-hour**	**1-hour**	**0.5-hour**
	Low	1,520	601	448	**Low**	1,295	512	382	**Low**	1,064	421	314	**Low**	936	370	276
	Mid-Range	2,310	1,001	802	**Mid-Range**	1,967	852	683	**Mid-Range**	1,617	700	561	**Mid-Range**	1,422	616	494
	High	3,100	1,400	1,156	**High**	2,640	1,192	985	**High**	2,170	980	809	**High**	1,908	862	711
			2018				**2020**				**2025**				**2030**	
HIGH		**4-hour**	**1-hour**	**0.5-hour**		**4-hour**	**1-hour**	**0.5-hour**		**4-hour**	**1-hour**	**0.5-hour**		**4-hour**	**1-hour**	**0.5-hour**
	Low	1,520	601	448	**Low**	1,275	504	376	**Low**	928	367	273	**Low**	704	278	207
	Mid-Range	2,310	1,001	802	**Mid-Range**	1,937	839	673	**Mid-Range**	1,410	611	489	**Mid-Range**	1,069	463	371
	High	3,100	1,400	1,156	**High**	2,600	1,174	970	**High**	1,892	854	706	**High**	1,435	648	535

Notes:

Low estimates for 2018 are derived from: Ran Fu, Timothy Remo, and Robert Margolis. 2018. 2018 U.S. Utility-Scale Photovoltaics-Plus- Energy Storage System Costs Benchmark. (Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71714. https://www.nrel.gov/docs/fy19osti/71714.pdf).

High estimates for 2018 are derived from: Weissman, Matthew M. 2018. "In the matter of petition of Public Service Electric and Gas Company for its approval of its Clean Energy Future-Electric Vehicle and Energy Storage ("CEF-EVES") Program on a regulated basis." (General State Regulatory Counsel. Law Department PSE&G Services Corporation. Petition sent to NJ Board of Public Utilities. Oct 11, 2018).

Cost de-escalation trajectories are based on: Tsiropoulos, I., Tarvydas, D., Lebedeva, N., 2018. *Li-ion batteries for mobility and stationary storage applications – Scenarios for costs and market growth* , EUR 29440 EN, Publications Office of the European Union, Luxembourg, 2018, ISBN 978-92-79-97254-6, doi:10.2760/87175, JRC113360. (Table 15). http://publications.jrc.ec.europa.eu/repository/bitstream/JRC113360/kjna29440enn.pdf.

In the above-cited JRC series (Tsiropoulos), de-escalation from 2017-2020 is slightly faster in the moderate case than in that of the high case, though the high de-escalates faster in later years. The high de-escalation case for 2018-2020 has been adjusted using data from BloombergNEF to reflect an accerlerated short-term de-escalation rate in the high de-escalation rate scenario. See Sekine, Yayoi and Chiang, Yet-Ming, 2018. *Energy Storage in Our Clean Energy Future* (http://www.caiso.com/Documents/Session3-DrYet-MingChiang-YayoiSekine.pdf).

Literature Review in Support of the Cost-Benefit Analysis

Several states have already investigated incorporating Energy Storage into their Clean Energy programs. Some of these states include Massachusetts, Nevada, New York, North Carolina, and Texas. This section presents an overview of the Energy Storage plans for each state (as well as reports developed by EIA and the Energy Storage Association) and tables that compare various metrics and assumptions that are found in each state's plan.

Massachusetts Energy Storage Initiative[7] (2016)

The Massachusetts Energy Storage Initiative Study presented a variety of policy recommendations which aimed to generate 600 MW of advanced energy storage in the Commonwealth by 2025. The study analyzed the economic benefits and market opportunities for energy storage in the state, as well as examined potential policies and programs that could be implemented to better support both energy storage deployment and growth of the storage industry in Massachusetts. Some of the modeling scenarios included:

- The optimal amount of advanced storage in MW and MWh to be added over the next 5 years – through 2020 – that will add maximum benefit to ratepayers;
- The distribution of energy storage locations across Massachusetts where adding storage will achieve maximum benefits to the ratepayers; and
- A quantification of the reduction in GHG emissions that can be achieved with the optimum level of energy storage deployments across the state.

The Energy Storage Initiative report also includes policy recommendations, statutory changes, and ISO NE recommendations. The policy recommendations include grant and rebate programs, storage in state portfolio standards, establishing/clarifying regulatory treatment of utility storage, options that include statutory change, other changes like easing interconnection, safety and performance codes and standards, and customer marketing and education.

The Economic Potential for Energy Storage in Nevada (October 2018)[8]

This study identifies the amount of energy storage that can be incorporated cost-effectively into Nevada's future electricity resource mix. In 2020, up to 175 MW of utility-scale battery storage (with 4-hour storage capacity) could be deployed cost-effectively statewide. By 2030, the economic potential for utility-scale storage increases to a range from 700 MW to more than 1,000 MW, depending most significantly on the extent to which storage costs decline over time. The study identified various energy storage value streams, including reducing the production costs of generating electrical energy and of providing ancillary services, reducing installed capacity needs for traditional power generation resources, reducing distribution-system customer outages, avoiding or deferring the need for transmission and distribution grid upgrades, reducing emissions and decreasing the curtailment of renewable generation, and providing additional grid services.

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[7] Massachusetts Department of Energy Resources, "State of Charge Massachusetts Energy Storage Initiative", 2016. https://www.mass.gov/service-details/energy-storage-study

[8] "The Economic Potential for Energy Storage in Nevada", PREPARED FOR Public Utilities Commission of Nevada Nevada Governor's Office of Energy, October 2018. http://energystorage.org/system/files/resources/economic_potential_for_storage_in_nevada_-_final.pdf

Overall, the results show that in 2020 benefits exceed total costs only at the low end of deployments analyzed (~200 MW), and only if the low end range of installed storage costs can be realized. In 2030, total benefits exceed total costs across the full range of cost projections and deployment scenarios, although the net benefit of incremental additions in 2030 drops to zero at 700 MW for the high battery cost scenario.

NY Energy Storage Roadmap[9] (June 2018)

According to the Energy Storage Roadmap, NYs goal energy storage goal is 1500 MW by 2025. During 2018, Governor Andrew Cuomo directed state agencies to generate a pipeline of storage projects through a number of mechanisms including utility procurements; major regulatory changes in utility rate design and wholesale energy markets; incorporating storage into criteria for large-scale renewable procurements; and reducing regulatory barriers.

In the plan, storage applications are grouped into 3 market segments: customer sited, distribution system, and bulk system

- Customer-Sited: Paired with on-site load and/or paired with DERs and located behind a customer's retail meter. This segment includes microgrids, electric vehicle charging management, and Residential solar + storage.
- Distribution System: Stand-alone or paired with DERs and connected directly on the distribution circuits. This segment includes expanded non-wires alternatives (referred to as "NWA+"), community distributed generation (CDG) + storage, and wayside storage to utilize regenerative braking in the New York City (NYC) subway system. Projects that export electricity under the VDER tariff are included in both this segment and the customer-sited segment based on the location of the system.
- Bulk System: Stand-alone or paired with generator connected at the bulk or transmission system level. The segment includes storage paired with renewables like solar or wind and standalone storage for targeted uses including capacity, ancillary services, short-duration frequency regulation, and peaker hybridization.

Each segment is projected to have 500 MW by 2025.

The Roadmap includes seven recommended actions, including Retail Rate Actions and Utility Programs, Investor-Owned Utility Roles, Direct Procurement Approaches through NWAs, RECs and NYS Leading by Example, Market Acceleration Incentive, Address Soft Costs including Barriers in Data and Finance, "Clean Peak" Actions and Wholesale Market Actions and Distribution / Wholesale Market Coordination.

New York State is agnostic about the specific technologies that will be used to meet its 2025 and 2030 storage targets. Storage deployments will be driven by several factors such as the overall evolution of energy storage technologies, the specific needs of the New York electric system, and the degree to which the actions recommended in this Roadmap are adopted and

[9] New York Public Service Commission, "New York State Energy Storage Roadmap and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations", June 2018.https://www.ethree.com/wp-content/uploads/2018/06/NYS-Energy-Storage-Roadmap-6.21.2018.pdf

implemented.

Energy Storage Options for North Carolina[10] (February 2018)

Under House Bill 589, the North Carolina Policy Collaboratory was tasked with producing a report on the value of energy storage to North Carolina consumers. The resulting report analyzed the potential role of storage within North Carolina. North Carolina investigated the following Energy Storage Applications:

- End-User Services: Considers behind-the-meter applications associated with residential, commercial, and industrial customers to reduce charges associated with peak demand and time-of-use rates by shifting when electricity demand occurs
- Distribution: Considers the use of storage to support the electricity distribution network, including reliability enhancement, capacity deferment, peak shaving, and voltage control
- Transmission Considers the use of storage to alleviate transmission congestion and defer new investments in transmission
- Generation and Resource Adequacy: Considers the use of storage to charge using low-cost generation, and discharge during high marginal price periods, defer investment in peaking capacity, provide frequency regulation to ensure the supply of grid electricity is balanced minute to-minute, and recover solar-generated electricity that would otherwise be clipped by an inverter

The results of North Carolina's analysis show that the projected cost reductions by 2030 shift many of the Li-ion battery scenarios to positive net benefits. In the end user services category, ice storage is already cost-effective. Though highly sensitive to siting constraints, both pumped hydro and compressed air energy storage may be cost-effective options today for bulk energy time shifting and peak capacity deferral. Additionally, in a future with higher natural gas prices, the relative cost-effectiveness of energy storage for bulk energy time shifting increases significantly. Energy storage proves to be more cost-effective with higher solar penetrations because low marginal cost solar can be captured and time shifted. The capacity value assigned to energy storage, defined as the fraction of installed capacity that can be relied upon during peak demand periods, is a key determinant of its overall value.

Among the services studied, frequency regulation provides the highest net benefits and represents a key near-term opportunity for storage. Data from competitive markets (PJM and NYISO) provide a strong indication that batteries can cost effectively provide this service.

[10] NC State Energy Storage Team, "Energy Storage Options for North Carolina ", December 2018.https://energy.ncsu.edu/storage/wp-content/uploads/sites/2/2018/12/NC-Storage-Study-FINAL.pdf

The Value of Distributed Electricity Storage in Texas Proposed Policy for Enabling Grid-Integrated Storage Investments, March 2015[11]

As battery costs decrease, Oncor Electric Delivery Company (Oncor), a Transmission and Distribution Service Provider (TDSP) in Texas, engaged a study on the economics of grid-integrated storage deployment in Texas. The various value streams of storage that were evaluated included those achieved in the T&D systems and those achieved through participation in wholesale energy and ancillary services markets. The study evaluated whether and at what deployment levels storage can be cost-effective from the perspectives of wholesale electricity market participants, retail customers, and the combined system or society as a whole. They found that up to 5,000 MW (15,000 MWh, assuming a three-to-one ratio of storage to discharge capability) of grid-integrated, distributed electricity storage would be cost effective from an ERCOT system-wide societal perspective, based on a forecast of installed cost of storage of approximately $350/kWh and would reduce the need for new generation by approximately 3,100 MW. From an average electricity customer's perspective, the analysis shows that deploying 3,000 MW (9,000 MWh) of storage across ERCOT would reduce residential customer bills slightly and provide additional reliability benefits in the form of reduced power outages for customers located in areas where storage is installed.

Table D7 summarizes the wide range of storage benefits estimated in various prior studies that were reviewed in the Brattle study.

Table D7: Storage Benefit Estimated in Other Studies

Type of Benefits	Study	Value in $/kW	Value in $/kW-yr
Ancillary Services			
Load Following	Sandia (2010)	$785-$2,010	
Area Regulation	Sandia (2010)	$600-$1,000	
Regulation	EPRI (2010)	$255-$426	
Regulation	Denholm and Letendre (2007)	$236-$429*	
Regulation	Walawalker et al. (2007)	$163-$248*	
Regulation	Byrne and Silva-Monroy (2012)	$117-$161*	
Operating Reserves	Sandia (2010)	$57-$225	
Spinning Reserves	EPRI (2010)	$80-$220	
Contingency Reserves	Denholm and Letendre (2007)	$66-$149*	
Voltage Support	Sandia (2010)	$400	
Voltage Support	EPRI (2010)	$9-$24	
VAR Support	EPRI (2010)	$4-$17	
Ancillary Services	Denholm et al. (2013)		$115-$128
Arbitrage			
Retail Time-of-Use Energy Charges	Sandia (2010)	$1,226	
Retail Time-of-Use Energy Charges	EPRI (2010)	$1,508-$3,258	
Energy Arbitrage	Sandia (2010)	$400-$700	
Energy Arbitrage	EPRI (2010)	$134-$800	
Energy Arbitrage	Sandia (2010)	$49	
Energy Arbitrage	Kirby (2012)	$46*	
Energy Arbitrage	Figueiredo et al. (2006)	$37-$45*	
Energy Arbitrage	Walawalker et al. (2007)	$29-$240*	

[11] http://files.brattle.com/files/5977_the_value_of_distributed_electricity_storage_in_texas_-_proposed_policy_for_enabling_grid-integrated_storage_investments_full_technical_report.pdf

Energy Arbitrage	Byrne and Silva-Monroy (2012)	\$25-\$41	
Energy Arbitrage	Kinter-Meyer et al. (2013)		\$101-\$116
Energy Arbitrage	Sioshansi et al. (2009)		\$60-\$110
Energy Arbitrage	Jenkin and Weiss (2005)		\$50-\$75
Production Cost Savings	Denholm et al. (2013)		\$23-\$75
Capacity			
Avoided Capacity Investment	Sandia (2010)	\$359-\$710	
Avoided Capacity Investment	EPRI (2010)	\$88-\$726	
Retail Demand Charges	EPRI (2010)	\$710-\$5,049	
Retail Demand Charges	Sandia (2010)	\$582	
Renewables			
Renewables Capacity Firming	Sandia (2010)	\$709-\$915	
Wind Integration, Short Duration	Sandia (2010)	\$500-\$1,000	
Wind Integration, Long Duration	Sandia (2010)	\$100-\$782	
Renewable Energy Integration	EPRI (2010)	\$104-\$1,866	
Renewable Energy Time-Shift	Sandia (2010)	\$233-\$389	
T&D			
T&D Upgrade Deferral	EPRI (2010)	\$1,242-\$6,444	
T&D Upgrade Deferral 90th Percentile	Sandia (2010)	\$759-\$1,079	
T&D Upgrade Deferral 50th Percentile	Sandia (2010)	\$481-\$687	
Transmission Support	Sandia (2010)	\$192	
Transmission Congestion Relief	EPRI (2010)	\$114-\$2,208	
Transmission Congestion Relief	Sandia (2010)	\$31-\$141	
Substation On-site Power	Sandia (2010)	\$1,800-\$3,000	
Electric Reliability and Power Quality	Sandia (2010)	\$359-\$978	
Power Reliability	EPRI (2010)	\$47-\$537	
Power Quality	EPRI (2010)	\$19-\$571	
Multiple Benefits			
Arbitrage and Contingency Reserves	Dury et al. (2011)	\$38-\$180*	
Arbitrage and Regulation	Kirby (2012)	\$62-\$75*	
T&D, Capacity, Arbitrage, A/S	Kaun and Chen (2013)	\$1,000-\$4,000	

Note: *Compiled in Denholm et al. (2013), Table 2-1

EIA US Battery Storage Market Trends[12] (May 2018)

This EIA report describes the current state of the market, including information on applications, cost, and market and policy drivers. Some trends relevant to NJ and PJM include:

- Nearly 40% of existing large-scale battery storage power capacity (and 31% of energy capacity) lies in the PJM Interconnection. In 2012, PJM created a new frequency regulation market product for fast-responding resources, the conditions of which were favorable for battery storage. However, recent changes in PJM's market rules have slowed battery installations in the region. Most existing large-scale battery storage power

[12] US Energy Information Administration, "US Battery Storage Market Trends", May 2018. https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf

capacity in PJM is owned by independent power producers providing power-oriented frequency regulation services.

- Lithium-ion represented more than 80% of the installed power and energy capacity of large scale battery storage in operation in the United States at the end of 2016.
- Nickel-based batteries have limited deployment in the United States (since the early 2000's). Nickel-based batteries typically have high energy density and reliability but relatively low cycle life.
- Sodium-based battery storage accounted for 3% of the installed large-scale power capacity and 12% of the installed large-scale energy capacity in the United States at the end of 2016. This type of battery storage is a mature technology based on abundant materials with a long cycle life that is suitable for long-discharge applications.
- Lead acid is one of the oldest forms of battery storage, with development beginning in the mid1800s. Lead acid is a mature technology that is widely used in passenger vehicles. Lead acid covered only 2%–3% of large-scale battery storage capacity installed in the United States at the end of 2016 and has seen limited grid-scale deployment because of its relatively low energy density and cycle life.
- Flow battery systems have a long cycle life, and their operational lifetime is projected to be long. Within the United States at the end of 2016, flow batteries represented less than 1% of the installed power and energy capacity of large-scale battery storage.

Table D8 below is shows cost Estimates for Large-Scale Battery Storage by Duration (<14 MW and <17 MWh systems for the US).

Table D8: Cost Estimates for Large-Scale Battery Storage by Duration

	Short Duration <0.5 hours	**Medium Duration 0.5-2 hours**	**Long Duration >2 hours**
Number of battery systems reported	10	10	8
Average of nameplate power capacity (MW)	13.0	13.8	2.7
Average of nameplate energy capacity (MWh)	4.7	15.6	16.7
Average of nameplate duration, hours	0.4	1.1	5.6
Capacity-weighted cost per unit power capacity ($/kW)	944	1,533	2,430
Capacity-weighted cost per unit energy capacity ($/kWh)	2597	1352	399

Energy Storage Association Advanced Energy Storage in Integrated Resource Planning[13] (2018 Update)

The Energy Storage Association (ESA) guide offers suggestions on including Energy

[13] Energy Storage Association, "Advanced Energy Storage in Integrated Resource Planning (IRP): 2018 Update", June 2018. http://energystorage.org/system/files/attachments/esa_irp_primer_2018_final.pdf

Storage in IRPs. The ESA recommends that commissions should require their regulated utilities to include energy storage as an investment option in the resource screen of their IRPs. Additionally, instead of only factoring demand resources into load forecasts, utilities can separately analyze controllable customer-sited resources such as energy storage as a potential supply option.

Energy storage technologies are projected to have price declines of 8%-15% per year into the future. Thus, it is important to update cost estimates annually. Recent studies have offered a wide variance in the costs of Lithium ion battery storage (4 hour duration) from around $1300/kW - $2400/kW.

According to the guide, IRP modeling needs to be updated to properly account for advanced energy storage. For instance, models that use sub-hourly intervals can capture the flexibility of storage operations to provide both capacity and grid services.

Some of the operational benefits that accrue to the system as a result of Advanced energy storage include reduced operating reserve requirements, reduced start-up and shut-down costs of generating fleet, improved heat-rate of thermal plants and consequently reduced emissions, reduced uneconomic dispatch decisions, reduced curtailment of renewable resources, reduced risk of exposure to fuel price volatility, and reduced local emissions and lack of service interruption from environmental restrictions. Massachusetts' energy storage study found that these avoided costs were greater than the direct, compensated services of storage.

Energy Storage has been included in the IRPs for Hawaii Electric, Kentucky Power, Indianapolis Power and Light, Arizona Public Services, Tucson Electric Power, PNM, Puget Sound Energy, and Florida Power and Light, among others.

Table D9 shows a comparison between New York, Massachusetts, North Carolina and Nevada on the Overall Energy Storage MW goal, the overall policy goals of the program and which technologies were reviewed in the analysis. Texas was not included in this table because the report from that state did not include any of those data points.

Table D9: Energy Storage Goals.

	New York	**Massachusetts**	**North Carolina**	**Nevada**
Overall MW Goal	1500 MW by 2020	600 MW by 2025	No Goal Specified	No Goal Specified
Policy Goals	An electric system that is cleaner, more resilient, and affordable. Also want to stimulate 3rd party investment, increase pace of technology cost reductions, and remove soft cost/finance/bankability impediments.	Enhance efficiency, affordability, resiliency, and cleanliness of entire electric grid.	Ensure reliable service, decrease cost to ratepayers, and reduce environmental impacts of energy production.	Nevada Senate Bill 204 (2017) requires the Public Utilities Commission of Nevada (PUCN) to "determine whether it is in the public interest to establish by regulation biennial targets for the procurement of energy storage systems by an electric utility." Study to provide information to be used by the PUCN when evaluating whether procurement targets for energy storage systems should be set and, if so, at what levels energy storage deployment would be

				economically beneficial for the state of Nevada.
Technologies Reviewed	None Specified	None Specified	Technologies reviewed included pumped hydro storage, flywheels, compressed air energy storage, lead acid batteries, lithium-ion batteries, sodium sulfur batteries, vanadium redox flow batteries, power-to-gas via hydrogen electrolysis, chilled water, ice storage, water heater energy storage, super capacitors, and superconducting magnetic energy storage.	Study simulates batteries with operational characteristics that resemble lithium ion (Li-Ion) chemistry, as Li-Ion systems are the predominant battery technology being deployed and contracted today.

Table D10 shows the energy storage challenges that were highlighted in the reports for New York, Massachusetts, North Carolina, and Nevada. Again, Texas was not included because no challenges were discussed in the report for that state.

Table D10: Energy Storage Challenges.

	New York	**Massachusetts**	**North Carolina**	**Nevada**
Energy Storage Challenges Identified	The inability to monetize the full value of storage, limited routes to existing markets, lack of confidence in performance and lifetime, lack of common financing vehicles, high soft costs, insufficient data on siting and customers, and high storage costs	Uncertainty regarding regulatory treatment, barriers in wholesale market rules, limitations in the ability for project developers to monetize the value of their energy storage project, and the lack of specific policies and programs to encourage the use of innovative storage technologies.	Cost competitiveness of technology, regulation uncertainties, and technology acceptance.	Some of the benefits of storage may not be fully additive, uncertainty in the costs and benefits of storage, cost-effectiveness of energy storage decreases as its market penetration grows.

Table D11 presents both the policy and cost reduction considerations presented in the New York, Massachusetts and North Carolina reports. Note that Texas and Nevada are not included in Table D11 because these issues were not discussed in their respective reports.

Table D11: Policy and Cost Reduction Considerations.

	NY	MA	NC
Policy Considerations	• Utilities should develop an optional rate that implements a more granular time - and location - varying daily as - used demand rate and include rate certainty during this pilot tariff period (e.g., Con Edison's Rider Q includes a 10 - year rate fix). • To limit the impact of shifting costs to non - participating customers, a MW enrollment limit, similar to the current 50 MW enrollment limit in the Con Edison Rider Q, should be developed and adopted. • Challenges associated with energy storage providing wholesale only vs. wholesale and retail services also require examination because FERC Order 841 allows storage located on distribution circuits to charge at LBMP when providing wholesale services.	• Project Demonstration Grants to quickly spur the market to deploy projects. • C&I Rebate Program for Behind the Meter Storage Projects • Grant Funding for Feasibility Studies at C&I Businesses • Adding energy storage as eligible technology under other existing grant programs • Grant Program to Demonstrate Peak Demand Savings • Amend Alternative Portfolio Standard (APS) to Include All Types of Advanced Energy Storage • Tailor new incentive program design to encourage Solar Plus Storage applications • Coordinate and facilitate the adoption of safety and performance codes and standards for energy storage systems. • Explore with the utilities the proper process for interconnecting electricity storage • Accelerate market adoption of energy storage with consumer education, awareness and marketing • Facilitate load data collection and energy storage system specification development for different classes of consumers towards driving down transaction costs	• Recent IRPs filed by both Duke Energy Carolinas and Duke Energy Progress include battery storage explicitly. The IRPs also discuss a shift to Integrated System and Operations Planning (ISOP) to better capture the role of emerging technologies like battery storage in generation, transmission, and distribution. • Up to $1 million for R&D, potentially including storage, is authorized for cost recovery under the North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (REPS). • Avoided cost calculations will be refined so as to provide clearer signals to qualifying facilities to further facilitate the deployment of advanced solar or storage applications, largely by reducing the number of on-peak hours while increasing rates paid. • Current statutes need to clarify what approvals are needed for energy storage facilities. • County and municipal level decisions regarding contracting, zoning, fire codes, and decommissioning requirements are likely to affect deployment and operation of storage.
Cost Reduction	• NYS is developing a bridging mechanism of $350 million to develop a scalable and self-sustaining market. Project should be deployable within the next three to	Not expressly addressed, though some ideas were suggested: • Tailor funding programs to support energy storage technology research, development and	Suggestions to Improve Cost Competitiveness include direct financial incentives (direct grants or tax incentives), the creation of markets or other mechanisms to

	five years. • Hard costs can be reduced using NY Green Bank, leveraging ITC and PACE financing. • Soft costs associated with customer acquisition, siting and permitting, and interconnection also need to be addressed.	demonstration (RD&D). • Support energy storage technology developer access to dedicated technology testing facilities. • Support for Early Stage Technology Demonstration	generate value for storage systems (time-of-use or other favorable rate structures, or other price signals such as demand charges, demand reduction auctions, or other incentives for customer or BTM systems), various financing approaches to specifically support the installation and operation of storage or energy regulations that recognize and/or help to monetize the multiple services provided by energy storage. Also important is clarification of ownership and how storage is classified for the purposes of transmission and distribution cost recovery. Finally, the use of procurement targets to create certainty for future capacity demand is likewise discussed in the literature

Table D12 presents the assumptions used in the various reports for Li-ion Batteries, which were the energy storage technology most discussed. North Carolina's analysis included data for various durations of batteries and also other energy storage technologies. Also, please note that Texas presented data for batteries associated with merchant and utility level projects. EIA data shown here is range for short duration (<0.5 hours) to long duration (>2 hours)

Table D12: Lithium Battery Input Assumptions.

	Massachusetts	**North Carolina**	**Nevada**	**Texas**	**New York**	**EIA**
Maximum Plant Life (yrs)	10	10	15	15 (merchant) 30 (utility)	10 (stand-alone) 25 (paired)	
Discharge Duration (Hours)	1	1	4		6 hours (NWA case) 4 hours (all other cases)	0.4-5.6
Depth of Discharge	0.8				100%	
Capacity (kW)	1000		5000			2700-13000

AC-AC Roundtrip Efficiency	0.85%	0.85%			85%	
Capital Cost ($/kWh)	600	658.9 (w/ITC)	$300-$450	$350-$500	$378-$401	$399-$2597
Fixed O&M ($/kW-yr)	10	4	$136-$204	1%-2% of installed cost		

Table D13 presents the various financial and economic assumptions that were discussed in the reports for Massachusetts, New York, Nevada, and Texas. Please note that North Carolina's report did not include any financial or economic assumptions.

Table D13: Financial and Economic Assumptions.

	MA	NY	NV	TX
Financing Inputs				
Ownership Type	IPP			
% Debt	40%	40%		
Debt Interest Rate	7.49%	7%		
% Equity	60%	60%		
After Tax Nominal WACC	8%	12%	7%	8% (merchant) 6.36% (utility)
Return on Equity	10.35%			
Economic Inputs				
Inflation Rate (%/Year)	2%		2%	
Fuel Escalation Rate (%/Year)	1%			
Tax Inputs				
Federal Income Tax Rate %	35%		21% Total Income Tax Rate	
State Income Tax Rate %	8%			
Property Tax Rate %	0%			
MACRS Term (Years)	7		15	
% of Capital Cost Eligible for ITC	100%			

The increase in energy storage projects will also increase the number of available jobs, according to several studies that were reviewed. Table D14 presents various estimates of energy storage jobs per MW installed, plus two estimates of jobs per dollar invested.

Table D14: Energy Storage Job Estimates.

Year	Navigant (2017) [14]	Solar Foundation (2016)[15]
2016	403.7	
2021	50.9	Utility Scale: 1.15

[14] Source: https://www.navigantresearch.com/news-and-views/energy-storage-industry-jobs-linked-to-energy-storage-capacity, accessed on March 11, 2019.
[15] Solar Foundation, "Solar + Storage Jobs: A Discussion Paper", 2016. http://www.thesolarfoundation.org/wp-content/uploads/2016/07/Solar-Storage-Jobs-A-Discussion-Paper-7.21.pdf

		Non-Residential:3.41 Residential: 15.91
2025	32.5	
CT (2016)[16]: $1 million investment =5.1 job-years for energy installers		
KEMA (2010)[17]: $1 million in sales revenue = 5 direct jobs		

According to Navigant research in 2017, the number of jobs per incremental MW in the storage industry is expected to decrease from 403.7 in 2016 to 50.9 in 2021 and 32.5 in 2025. It is expected that there will be a total of 368,836 jobs in 2025.

In 2016, the Solar Foundation developed a Solar+ Storage Jobs Discussion Paper which looked at storage deployment/installation employment. They based their estimates on Solar jobs per MW data that was adjusted to convert solar jobs to storage jobs. The paper explicitly states that "these calculations are very subjective requiring further research." The paper looked at storage jobs per MW in 2021 by sector (utility scale, non-residential, and residential). The job estimates ranged from 1.15 jobs per MW for utility scale projects to 15.91 jobs per MW for residential projects.

A 2016 report from the Connecticut Green Bank sought to estimate the economic development benefits (i.e., job-years created) from clean energy investments in Connecticut. The study estimates that a $1 million investment creates 5.1 job-years for energy installers. This was divided between 2.2 Direct Job-years and 2.9 Indirect and Induced Job-years.

A 2010 KEMA report evaluated and developed potential job creation estimates associated with the STORAGE Act of 2009. The study estimated that five direct jobs would be created per $1 million in sales revenue.

[16] Connecticut Green Bank, "Clean Energy Jobs in Connecticut", August 2016. https://ctgreenbank.com/wp-content/uploads/2017/02/CTGReenBank-Clean-Energy-Jobs-CT-August102016.pdf
[17] KEMA-Electricity Storage Association, "Assessment of Jobs Benefits from Storage Legislation", March 2010. https://www.ice-energy.com/wp-content/uploads/2016/04/kema__esa_jobs_benefit_report_03_31_10.pdf