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June 21, 2018

VIA ELECTRONIC MAIL

Honorable Kathleen H. Burgess, Secretary
New York State Department of Public Service
Three Empire State Plaza
Albany, NY 12223-1350

Dear Secretary Burgess,

Attached please find the New York State Energy Storage Roadmap and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations (Roadmap), to be filed in Case 18-E-0130, In the Matter of Energy Storage Deployment Program. The Roadmap is accompanied by two appendices, which shall also be filed. Should you have any questions or concerns, please contact me.

Sincerely,

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Assistant Counsel
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New York State Energy Storage Roadmap

and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations

Contents

Executive Summary

Introduction

In January 2018, Governor Andrew M. Cuomo announced a target to install 1,500 megawatts (MW) of energy storage in New York State (NYS or "the State") by 2025. In doing so, he directed State energy agencies and authorities to work together during 2018 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.

Under Governor Cuomo's Reforming the Energy Vision (REV), New York is transforming its electricity system into one that is cleaner as well as more resilient and affordable. Energy storage technologies will play an increasingly important role in this transformation. Through lowering the cost and speeding the deployment at scale of storage solutions and drawing on innovation and investment from all sectors, energy storage will create the most value for customers and the state's energy system in the new energy paradigm. This nation-leading energy storage initiative builds upon and reinforces New York's commitment to undertaking bold efforts to address climate change, build an economy based on clean energy, and foster innovation.

Energy storage will serve many critical roles to enable New York's clean energy future. As intermittent renewable power sources like wind and solar provide a larger portion of New York's electricity, storage will be used to smooth and time-shift renewable generation and minimize curtailment (the need to reduce output due to grid limits). As New York's grid becomes smarter and more decentralized, storage will be deployed to store and dispatch energy when and where it is most needed. Storage will also allow New York to meet its peak power needs without relying on its oldest and dirtiest peak generating plants, many of which are approaching the end of their useful lives. The numerous services that energy storage can provide can also be "stacked" (same resource provides multiple system needs) and performed either at the same time or with the same resource. This operational flexibility is especially important as the electric system evolves to become more decarbonized, decentralized, and complex.

This Roadmap, developed by the Staff of the New York State Department of Public Service (DPS) and the New York State Energy Research and Development Authority (NYSERDA) (jointly "Staff") in conjunction with numerous stakeholders, develops an approach and a series of recommended actions that are intended to achieve the Governor's 1,500 MW target in a manner that reflects the principles underpinning REV:

- Improve the overall efficiency of the electric system by stimulating third-party investment alongside public and utility investments.
- Reveal and reward electric system value – value that is frequently granular in time and location.
- Spur the pace of cost reductions by supporting markets at scale and promoting competition.
- Remove impediments, especially those relating to soft costs (e.g., permitting, interconnection, customer or site acquisition, data access to target the highest-need and most valuable locations), finance, and project bankability.

Benefits of Storage Deployments

The Roadmap identifies the most promising near-term policies, regulations, and initiatives needed to realize the Governor's ambitious 2025 energy storage target in anticipation of a 2030 target to be established later this year, per legislation, by the New York State Public Service Commission (PSC or "the

Commission").[1] Deploying 1,500 MW of energy storage by 2025 will bring a host of benefits for New York, including:[2]

- **Nearly $2 billion in gross lifetime benefits** to New York's utility customers, according to a state-sponsored analysis by the consulting firm Acelerex.[3]
- **Adding flexible resources** that can be available when needed**,** which will become more valuable as the state adds more renewable energy (both at small and large scales) and will enable these resources to meet periods of peak demand.
- **Avoiding more than one million tons of CO_2 emissions** over the life of the storage assets (estimated at 10 years). The carbon benefits from adding energy storage grow substantially as the state approaches higher levels of renewable generation that would otherwise be curtailed, especially at night. Charging the storage with off-peak renewable energy to discharge and displace fossil generation during peak periods of demand will provide a substantial benefit to the state's carbon footprint and air quality.
- **Adding resiliency to the electric system by reducing the impact of outages.** For illustrative purposes, 1,500 MW of storage is the equivalent electric demand of one-fifth of all New York State homes.
- **Protecting public health by meeting many of the peaking needs currently served by older and higher-emitting fossil plants that may be close to retirement**, many of which typically reside in environmental justice areas. Off-peak charging reduces emissions of particulate matter and nitrogen oxides which are often more critical at times of peak electricity demand.
- Creating on the order of **30,000 jobs in the storage sector by 2030[4]**, as more and higher-skilled workers are called upon to meet growing demand and New York becomes a home for this rapidly expanding clean tech industry.

While the Roadmap describes a longer-term (2026-2030) vision, its primary focus is to identify deployment opportunities, use cases, and implementable actions that New York State can undertake to support deployment of various energy storage applications in the near-to-medium term (2019-2025). It groups storage deployment applications into **three market segments** – **customer-sited, distribution system** and **bulk system** – based on where the storage is located on the electric grid and the needs it serves. The primary use cases, benefits and services of storage in each market segment are:

<u>Customer-sited deployments</u>

- Demand charge management
- Value of Distributed Energy Resources (VDER) services via the value stack
- Dynamic load management including demand response

<u>Distribution system deployments</u>

- Utility transmission and distribution (T&D) solutions providing distribution relief, peak demand relief and wholesale market services
- Local reliability services

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[1] *See* Public Service Law (PSL) §74.
[2] *See* Appendices A-B for more details on the types of storage and its benefits.
[3] *See* Appendix K for the results from the Acelerex study.
[4] *See* Press Release, Governor Cuomo Unveils 20th Proposal of 2018 State of the State: New York's Clean Energy Jobs and Climate Agenda (January 2, 2018), https://www.governor.ny.gov/news/governor-cuomo-unveils-20th-proposal-2018-state-state-new-yorks-clean-energy-jobs-and-climate.

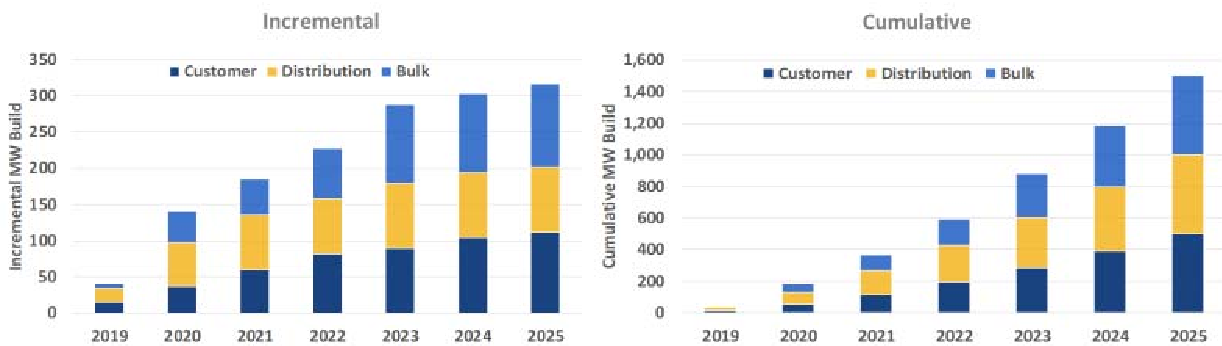
Bulk system deployments

- Firming resource when paired with large-scale intermittent renewables
- Peaker replacement/complement and "clean peak" services
- Bulk wholesale services and potential opportunities for bulk transmission deferral

Storage Market Opportunities

The Roadmap includes a market sizing estimate, for each market segment, of a storage deployment scenario that would achieve New York State's 1,500 MW targetby 2025, as shown in Figure ES1 below. This sizing shows storage deployment gradually increasing over the near term as the market is accelerated via adoption of the Roadmap's recommended actions. Under this scenario, each segment of deployments (customer-sited, distribution system and bulk system) is estimated to reach 500 MW by 2025. This scenario was informed by the project economics and market sizing estimates that E3 prepared and the Acelerex energy storage study and reflects one path for reaching 1,500 MW by 2025.

Figure ES1. Deployment Scenario Resulting in 1,500 MW of Storage by 2025



Beyond 2025, analysis performed by Acelerex showed that the deployment of 2,800-3,600 MW of energy storage by 2030 results in ratepayer benefits exceeding $3 billion.[5] 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. Although the analysis utilized the best-available system mapping, it was nonetheless limited in its distribution system detail and consequently neither reflects an upper bound of ratepayer benefit[6] nor maximizes the amount of storage that can be deployed in the state.

Roadmap Approach

The Roadmap describes a longer-term end-state vision and identifies deployment opportunities, use cases, and implementable actions that the State and various market actors can undertake to accelerate deployment of high-value storage applications. It also highlights roles and responsibilities of relevant entities involved in realizing and enabling storage value and directly implementing recommended actions. The Roadmap is technology-agnostic and recognizes that a range of storage solutions will be deployed to best meet customer and system needs. The Roadmap was developed through the following activities:

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[5] *See* Appendix K.

[6] Additional benefits from transmission deferral and reliability are not included, since the Acelerex study utilized a fixed transmission model. As a conservative assumption, hard limits were placed on the amount of storage that could provide ancillary services (25%) and in zonal capacity (10%) in the base case (these were adjusted to 50% and 15% in the peaker sensitivity). Loss of load expectation was also not considered in the peaker sensitivity.

- Engaging stakeholders including customers, utilities, the New York Independent System Operator (NYISO) and other market participants through working groups, conferences and individual meetings, and leveraging input already received through DPS working groups (including VDER and rate design working groups).
- Identifying and modeling storage use cases reflecting a wide but not exhaustive range of potential installations.[7]
- Recognizing key challenges that must be addressed and actions that can be taken in the near and medium term.
- Conducting an in-depth analysis of each use case to analyze storage value; develop, inform and test potential actions; estimate market uptake; and develop implementation pathways.
- Developing a set of recommended actions to propel the market toward a self-sustaining one that can respond to system needs and price signals and achieve maximum benefit for electricity customers.

Analysis and Key Takeaways

The Roadmap's analytical framework is grounded in the economics and value proposition of energy storage. Developing this framework involved first examining the costs of energy storage technologies and then comparing those costs with potential future value streams[8] for specific use cases and operations, financing and business models.

The **customer-sited** use cases examined storage applications for customer retail bill management and demand response within eight illustrative commercial, industrial or municipal customer types – selected based on their greater consistency with other customers' load shapes to examine the potential market impact from the recommended actions. Residential customers could also site storage, for instance when paired with a solar photovoltaic (PV) system.

Distribution system use cases analyzed VDER tariff compensation for electricity exported into the distribution system, non-wires alternatives (NWAs) with wholesale market participation, and PV paired with energy storage cases.

Bulk system use cases analyzed combinations of wholesale market services including energy arbitrage, capacity, spinning reserves and frequency regulation, high zonal congestion energy prices, and large scale renewables paired with energy storage. Dual market participation in which storage met distribution and wholesale system needs was examined. Project modeling was done in several utility territories and NYISO zones to provide a range of values.

Competitive ownership of storage in DER markets is core to REV principles, and therefore, the existing limitations on utility ownership should be maintained if possible. The project economic modeling that supported development of this Roadmap, which included various ownership assumptions, did not present a compelling economic reason to reexamine the Commission's decision on utility ownership of energy storage.[9] The REV Track One Order addressed the question of utility ownership of storage by recognizing that unrestricted utility participation in DER markets presented a greater risk of undermining markets

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[7] While many use cases were analyzed, the list was not exhaustive and certain use cases or specific projects will become economical sooner or later than what is indicated by the analysis, depending on specific project economics and the cost decline curve. Storage technologies and the electricity system as a whole are evolving; additional use cases and applications may emerge over time that this Roadmap analysis did not envision or analyze.

[8] In this report, "value streams," "benefits," and "revenues" are all synonymous and used interchangeably.

[9] *See* Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (REV Track One Order).

than a potential for accelerating market growth. The Commission ruled that utility ownership of DER would not be allowed unless markets have had an opportunity to provide a service and have failed to do so in a cost-effective manner and established specific exceptions to this ownership prohibition. Exceptions include: when procurement of DER has been solicited to meet a system need, and a utility has demonstrated that competitive alternatives proposed by non-utility parties are clearly inadequate or costlier than a traditional utility infrastructure alternative; when a project consists of energy storage integrated into distribution system architecture; when a project will enable low or moderate income residential customers to benefit from DER where markets are not likely to satisfy the need; or when a project is being sponsored for demonstration purposes.

While this approach remains the first best choice, recent proposals by the NYISO to subject energy storage resources in mitigated capacity zones to buyer-side mitigation measures could result in inappropriate barriers to entry.[10] This outcome would inappropriately mitigate resources that lack the incentive and ability to exercise market power, thereby preventing storage resources from accessing the wholesale capacity markets. If this outcome occurs, Staff recommends that the Commission reconsider whether utility ownership of storage could be a necessary option as a result of the de-facto absence of competitive capacity markets for storage resources.

Because an individual storage project's value proposition hinges on multiple potential value streams, value stacking is essential. However, since not all values can be realized today, and some may not evolve or be accessible until the future, this presents a significant barrier to unlocking the full potential of energy storage. Thus, the Roadmap's recommended actions aim to enable the realization of storage value, now and over time, while also reducing barriers and costs.

The upfront **breakeven installed cost of storage (BICOS)** is the primary analytical metric used in this Roadmap. BICOS indicates what the total upfront cost of storage must be for a project to be economically feasible, defined as the project benefits or values exactly equaling all costs to install, commission, finance and provide a return on the project over its life.[11] The higher the BICOS, the better the project's economics and the closer it is to commercial viability today based on current installed cost. This metric was useful given the range of storage technologies and current costs.

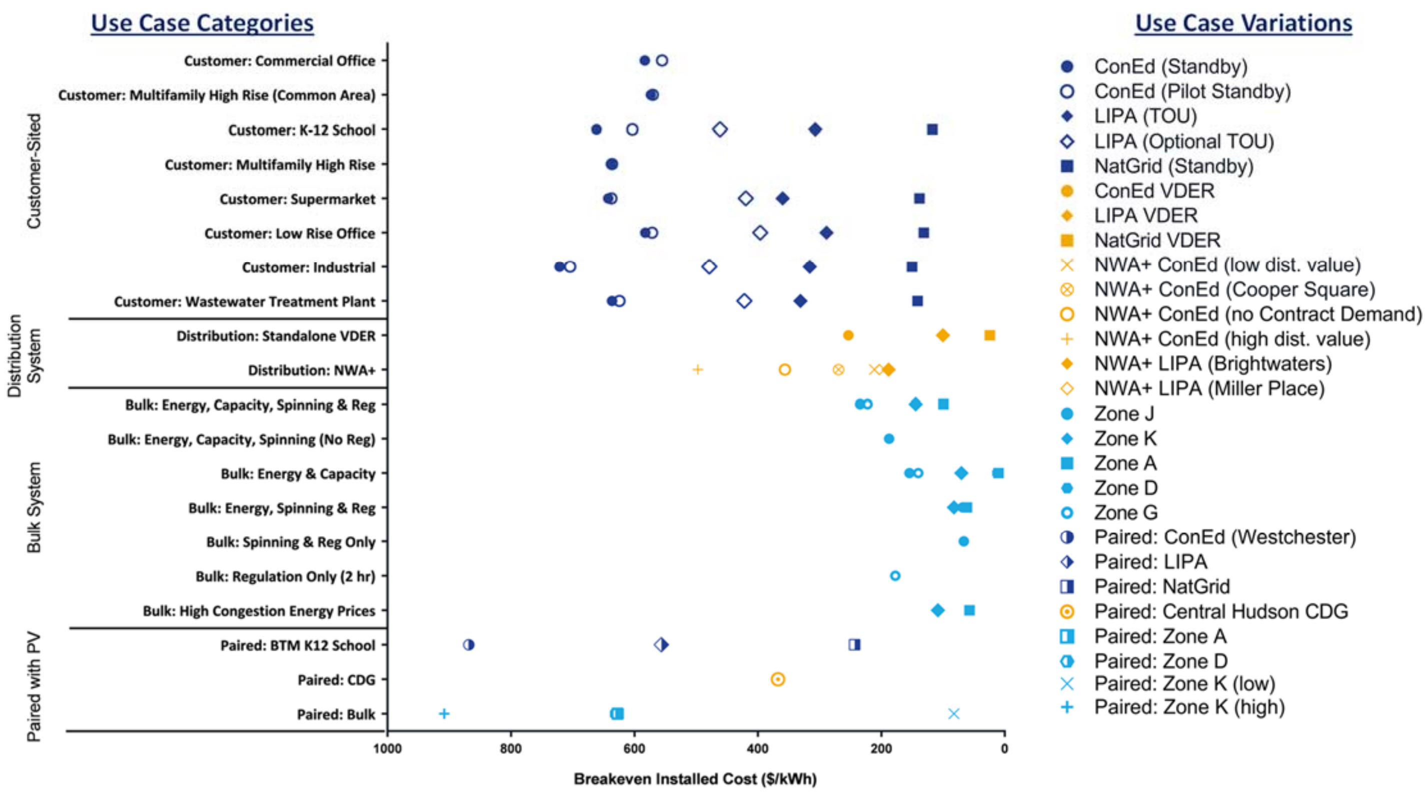
In general, **many customer-sited and distribution system use cases and paired solar + storage projects are, or will soon become, viable in downstate New York between now and 2025**. This is due to better project economics, where higher value streams offset higher costs. Economically attractive opportunities to pair storage with renewables and potentially to hybridize and/or replace fossil peaking units will also begin to arise, as will high-value distribution system use cases in upstate New York. In the longer term, numerous diverse use cases will become economic across New York, especially as the system adds more renewables and the cost of storage solutions continues to decline. Importantly, there will also be cases in which project economics far surpass the illustrative economics shown due to different load shapes and local electric system needs.

[10] *See* NYISO Presentation: Capacity Market Rules for Energy Storage Resources (May 23, 2018), http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2018-05-23/Initial%20ESR%20Capacity%20Model.pdf.

[11] The BICOS metric is not a levelized number itself, but it is calculated based on a project's levelized costs and benefits in order to determine the total upfront installed cost of storage so that the levelized costs exactly equals the levelized benefits.

The figure below summarizes the BICOS results across a number of diverse use cases.

Figure ES2. Economics (BICOS) of Various Storage Use Cases Comparing Revenue Streams to Total Cost Over System Lifetime[12]



As costs decline, more energy storage use cases become economically viable, as total upfront installed costs fall below the BICOS. By the early 2020s, large numbers of use cases are expected to be economically viable without incentives. This reinforces the need to accelerate the market learning curve now, reduce

[12] All stand-alone use cases were considered over a 10-year asset life inclusive of all costs including Operations and Maintenance (O&M). All paired cases considered were over a 25-year asset life inclusive of all costs including Repairs and Replacement and Operations and Maintenance.

Customer Assumptions: Storage sized at 10% of the customer's peak load for 4-hour duration. Discharge compensation is bill savings and Demand Response (DR) revenues. Third party financed: 60% equity at 12% and 40% debt at 7% for a 9.3% Weighted Average Cost of Capital (WACC) & discount rate. DR revenue considered for 10 years. 15% de-rate applied to revenues to reflect real world scenario without perfect foresight.

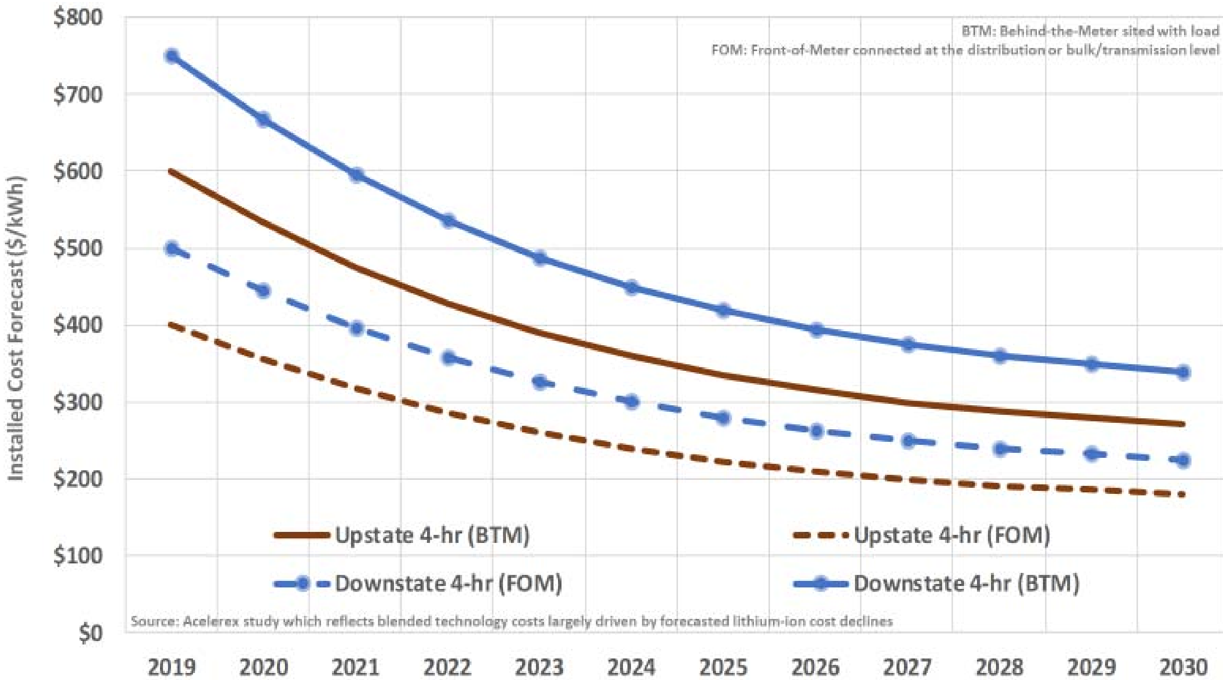
VDER Assumptions: Storage sized at 1 MW, 4-hour duration. Discharge compensation at VDER stack (LBMP, ICAP, DRV value lock for 7-years), charging at LBMP + Contract Demand. Third party financed: 100% equity at 12% WACC & 12% discount rate. 10% de-rate applied to revenues to reflect real world scenario without perfect foresight.

NWA+ Assumptions: Storage sized at 5% of substation peak load, 6-hour duration. Discharge compensation at estimated NWA value (DRV + LSRV), LBMP arbitrage, ICAP & spinning reserves; charging at contract demand + LBMP. Third party financed: 50% equity at 12% and 50% debt at 6% for an 8.2% WACC & discount rate. 10% de-rate applied to wholesale revenues to reflect real world scenario without perfect foresight. "No Contract Demand" charge is shown for Cooper Square with utility financing (48% Equity at 9% and 52% Debt at 4.74% for a 6.73% WACC & discount rate). High and low distribution values are shown for the Cooper Square illustrative example to reflect a range of potential NWA compensation.

Bulk Assumptions: Third party financed: 60% equity at 12% and 40% debt at 7% for a 9.3% WACC & discount rate. 10% de-rate applied to all revenues to reflect real world scenario without perfect foresight.

the amount of soft costs (i.e. non-hardware costs) embedded in the upfront installed cost, and increase the number of developers working in the state.

Figure ES3. Blended Energy Storage Cost Forecast for New York State by Upstate/Downstate Region



The Roadmap's key analytical takeaways are presented in the table below.

Key Takeaways from Roadmap Analysis	
Market Segment	***Takeaways***
All	• Value stacking is essential, particularly for distribution and bulk system storage. • Reducing installation and financing costs and/or developing a market acceleration bridge incentive can make projects more economical in the near term and dramatically reduce soft costs, accelerating the cost reduction curve. • Improving revenue certainty lowers financing costs and enables more values for storage to be bankable/financeable. • Details matter: storage economics are highly project-specific and identifying good-fit customers or sites is complex; hence, improving data access and identifying high-need areas of the electric grid are essential.
Customer-Sited	• Key drivers include customer "peakiness" (i.e., ratio of baseload to peak electric use), cost of demand charges and customer's value of resiliency. • Roadmap actions must balance revenue certainty for customers with maintaining dynamic price signals that reflect system needs.
Distribution System	• Rules around "dual market" participation (i.e., simultaneously meeting distribution and wholesale system obligations with the same asset) require clarity and immediate acceleration; rules to coordinate participation during periods when performance is committed to distribution priorities must be established. • Access to multiple markets increases and diversifies developer revenue; increasing access to distribution system data would facilitate planning and siting.

Key Takeaways from Roadmap Analysis	
Market Segment	***Takeaways***
	• Charging and interconnection costs and underlying distribution value will vary significantly within NWAs; obtaining non-distribution (i.e., wholesale market) values should be encouraged in distribution system applications (referred to as "NWA+").[13]
Bulk System	• As noted above, rules for "dual market" participation must be accelerated to realize the full potential of storage to meet system needs and yield ratepayer benefits as envisioned by the Federal Energy Regulatory Commission's (FERC) Order 841.[14] • Specific use cases in the bulk system may be attractive in the near term. Broadly replicating and scaling these will require considering the unique attributes of storage, especially its near-instantaneous response. Rules around aggregation, telemetry and metering must also evolve. • Storage is well suited to meet many of the peaking needs provided by older and higher-emitting fossil plants. It can also increase efficiency of these plants when paired. Economic and reliability analysis must be pursued to determine how battery peakers and/or DER including storage can perform reliability functions and where plant replacement, repowering and hybridization can be accomplished while continuing to meet reliability needs. Many of these plants are at (or past) their useful lives, and costly emission controls and capital upgrades may be better invested in new technology. • Paired solar + storage deployments are attractive given the ability of projects to firm solar production, receive the associated federal Investment Tax Credit (ITC). benefits, and potentially reduce interconnection costs by limiting power output. • Finally, storage opens a large new market for off-peak charging from both renewable generation and traditional generation.

Recommended Actions

The Roadmap's recommended policy, regulatory and programmatic actions have been developed to enable, support and accelerate New York's transition to its desired end-state vision for energy storage, which includes full use of DERs including storage to meet system needs; dispatchability and dynamic price signals; flexibility in enabling intermittent renewable resources like solar and wind to be used when needed most; and a thriving energy storage sector. The approach taken in this Roadmap is to develop rates, rules, and program designs that purposefully and specifically address barriers that impede the technology or resource types in order to enable all potentially valuable technology or resource types to participate effectively in the market. This will allow for technology-agnostic competition among technology (or technology-combination) solutions to achieve the best value for the system based on cost, value, functionality and timing.

To realize the end-state vision, the Roadmap recommends a range of policy, regulatory, and programmatic actions for consideration and implementation in the near-to-medium term (2019-25). These fall into seven general categories:

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[13] NWA+ represents use cases with utility T&D deferral value, reducing single peak system hour to provide capacity savings, and providing wholesale ancillary services.

[14] *See* Docket Nos. RM16-23-000 and AD16-20-000, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Final Rule (issued February 15, 2018) (Order 841).

- **Retail Rate Actions and Utility Programs**. Improve customer retail delivery rates and programs like utility dynamic load management programs to send more accurate price signals that correspond to the system-wide and locational value of peak load reductions and to reduce financing barriers.
- **Investor-Owned Utility Roles.** Enable development of a market-based storage sector and align utility incentives to that end by clarifying the role and business model for investor-owned utilities (IOUs) to manage the full customer bill, leveraging assets such as storage and expanded non-wires alternatives ("NWA+", where third-party assets provide utility T&D deferral, reduce generation capacity obligations by reducing peak system load, and provide ancillary services to the wholesale market).
- **Direct Procurement Approaches through NWAs, RECs and NYS Leading by Example**. Expand the market by employing direct procurement approaches through utility NWAs, NYSERDA's Renewable Energy Certificates (RECs) that can pair large-scale renewables with energy storage, and NYS "Lead by Example" procurement initiatives.
- **Market Acceleration Incentive.** Utilize market acceleration bridge incentives to hasten the market learning curve and reduce costs.
- **Address Soft Costs including Barriers in Data and Finance.** Pursue cross-cutting actions to reduce barriers including expanding access to more granular system load data to target highest-need locations on the electric system, lowering costs (e.g., permitting, interconnection, and capital costs), and insuring access to a skilled workforce.
- **"Clean Peak" Actions.** Align storage approaches with Department of Environmental Conservation (DEC) draft combustion turbine peaking unit regulations to reduce NOx and develop approaches to differentially value peak carbon reductions. This includes implementing "Clean Peak" actions through rate design, the market acceleration bridge incentive, REC procurements and a to-be-developed methodology for analyzing peaker plant operational and emission profiles on a unit-by-unit basis to determine best potential candidates for hybridization, repowering or replacement by storage.
- **Wholesale Market Actions and Distribution / Wholesale Market Coordination.** Develop approaches to directly or indirectly access wholesale market values (including capacity and ancillary service values) by modifying wholesale market rules to better enable storage participation, including dual market participation (i.e., where storage provides both distribution system and wholesale system services).

Market acceleration incentives merit special mention. Staff recommends establishing an approximately $350 million bridge incentive statewide, including in Long Island Power Authority (LIPA) and PSEG Long Island's service territory, to accelerate adoption of customer-sited storage and storage sited on the distribution or bulk systems, including pairing with PV. Incentive levels should be aligned with declining storage costs to accelerate cost declines, spur innovation, and enable a self-sustaining market without incentives. Staff recommends that existing sources of funds, such as those authorized under the Clean Energy Fund and other previously collected but currently uncommitted funds be identified to support this recommended funding commitment.

Staff estimates that such an incentive program could support a significant amount of customer-sited and distribution/bulk sited storage by 2021–22 while accelerating cost declines, deploying over one-third of the 1,500 MW 2025 target, and establishing critical foundations for a self-sustaining market without direct incentives. Staff estimates that a bridge incentive program could reduce soft costs by up to $50 per kWh for a distribution/bulk-sited system and up to $150 per kWh for a customer-sited system by 2025 compared to 2017-18 costs, thereby significantly improving project bankability. Moreover, this program is projected to accelerate the cost decline curve by almost two years and save approximately $200 million from the projected cost of deploying 1,500 MW of energy storage by 2025 and more than $400 million from the projected cost of deploying 3,000 MW by 2030.

Specific recommended actions within each of the seven general categories are presented below.

Category	Recommended Actions	Market Segment		
		Customer	Distribution	Bulk
Retail Rate Actions and Utility Programs to provide more accurate compensation and increase financeability	Apply optional, more granular daily as-used demand charges as a pilot tariff for demand metered customers, as delivery charge rate designs continue to better reflect cost-causation among customer classes through time and location	X		
	Re-examine charging/discharging rules and rates for energy storage connected at customer, distribution and bulk levels	X	X	X
	Extend DRV lock under the VDER value stack from 3 years to 7 years and implement a call signal	X	X	
	Create a 4-8 hour window for a statewide “peak ‘E’” Value within the VDER value stack that varies by season to recognize higher carbon emissions during peak periods	X	X	
	Offer multi-year load management contracts through utilities for 3-5 year terms	X	X	
Investor-Owned Utility Roles to enable a market-based storage sector and align utility incentives and business models to that end	Improve utility NWA procurement through greater visibility into future NWAs, interconnection costs, and NWA-eligible utility land; better data to indicate high-need areas of the electric grid; and other actions	X	X	
	Improve utility BCA framework by including optionality valuation, terminal value and greater transparency into the BCA application	X	X	
	Create a new EAM for each utility incentivizing distribution system-wide load factor improvement and peak reduction to align utility actions with DERs’ delivery of system value	X	X	
	Include an extension option for the utility to extend an NWA contracts when an asset’s life expectancy will exceed original NWA term	X	X	X
	Procure NWA+ that reduce system peak load and provide wholesale market ancillary services in addition to utility T&D deferral to provide greater ratepayer benefits by focusing on the full customer bill	X	X	X
	Allow developers to maintain a project’s interconnection for wholesale services after the NWA term if distribution services are discontinued	X	X	X
	Promote competitive procurement and third-party ownership of storage in DER markets as per REV Track One Order	X	X	X

Category	Recommended Actions	Market Segment		
		Customer	Distribution	Bulk
NYS Leading by Example to expand the market and engage public entities in State energy objectives	Leverage the State's purchasing power to act as a catalyst for early adoption of storage among municipal cooperatives, schools, public buildings, State University of New York, Office of General Services, Metropolitan Transportation Authority, and others	X	X	
Market Acceleration Incentive	Develop an Energy Storage Market Acceleration bridge incentive program that maximizes system benefits designed to provide required missing money at levels aligned with declining costs of the resource, in a manner so as to accelerate that cost decline and clearly establish an end-point that does not require incentives. The NY-Sun program will implement a PV plus storage incentive by fall 2018, followed by a new program for standalone or paired storage that will be determined through the Commission proceeding.	X	X	X
Addressing Soft Costs including Barriers to Data and Finance	Leverage NYGB and commercial PACE financing to achieve greater economies of scale and reduce the cost of capital / financing	X	X	X
	Require utilities to provide developers and operators with hourly load data (actual and forecasted) for substations connecting the distribution and bulk systems (i.e., transmission nodes) with increasing granularity provided over time	X	X	X
	Develop, implement, and maintain a searchable data platform containing aggregated customer-related data through utility and NYSERDA coordination	X	X	
	Build a skilled talent pipeline through workforce development	X	X	X
	Prepare an annual State of Storage report, led by DPS and NYSERDA, that tracks storage deployments, progress in meeting the 2025 and 2030 storage targets, impediments and recommended solutions that must be addressed	X	X	X
"Clean Peak" Actions[15] to align storage approaches with DEC draft combustion turbine peaking unit regulations related to NOx and effectively value differential carbon reduction at peak	Differentiate E value in the VDER value stack to reflect time of day/season marginal carbon emissions	X	X	
	Procure utility NWA solutions that defer utility T&D investment and reduce peak system loads which typically occur during periods of largest carbon emissions	X	X	X
	Calibrate the proposed bridge incentive to maximize carbon reduction based on aligning with local or system peak loads	X	X	
	Continue incentivizing energy storage paired with Large Scale Renewables through NYSERDA REC procurements (either co-located with the renewable or bid as a single REC price but located in a higher-value location on the grid)		X	X

[15] Some of these actions are repeated from other categories.

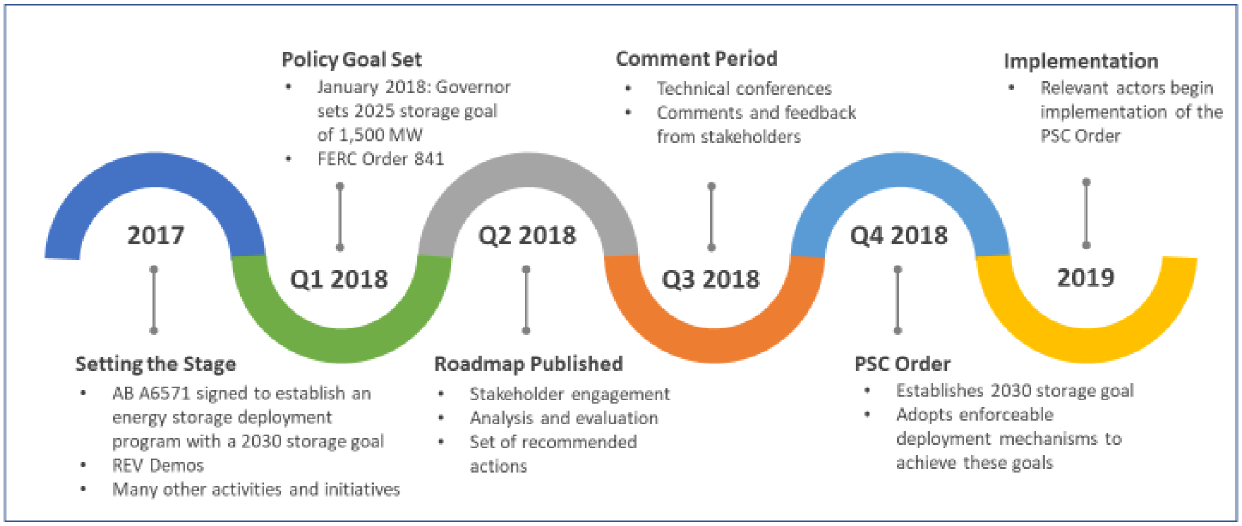
Category	Recommended Actions	Market Segment		
		Customer	Distribution	Bulk
	Partnership between DPS, NYSERDA, DEC, Con Edison, LIPA, NYISO and peaker plant owners to develop a methodology for analyzing peakers' operational and complete emission profiles on a unit-by-unit basis to determine best potential candidates for hybridization, repowering or replacement by storage		X	X
	Work in close coordination with DEC as potential NOx peaker regulations are developed, and order impacted utilities to develop a "Peaking Unit Contingency Plan" to address potential retirement of these generation facilities		X	X
	Continue to examine other mechanisms to enable cleaner generation to meet periods of peak electric demand	X	X	X
Wholesale Market Actions to directly or indirectly access wholesale market values	Implement changes enabling storage participation in capacity and ancillary services markets in compliance with FERC Order 841, and include storage as a transmission resource in NYISO planning			X
	Remove impediments to pairing storage with bulk renewables by re-examining how preferential treatment is applied for intermittent renewables that are partially firmed by storage			X
	Accelerate "dual market participation" by recognizing an asset may simultaneously provide distribution and wholesale system needs in the NYISO's electric storage resource participation model Order 841 compliance tariff filing		X	X
Distribution and Wholesale Market Coordination	Expand system planning to include integrated T&D planning	X	X	X
	Develop clear control, coordination and dispatch requirements including visibility into asset state of charge to enable greater use of DERs including energy storage in meeting system customer, distribution and wholesale system needs	X	X	X

Path Forward

Release of this Roadmap represents the beginning of the formal public input phase. DPS and NYSERDA Staff will be holding several technical conferences including on Long Island to present the Roadmap recommendations and seek input. Written feedback is also sought on the recommendations presented in the Roadmap, analytical findings, and any other items that stakeholders feel should be considered as the Public Service Commission establishes a 2030 storage target and enforceable deployment mechanisms. Case 18-E-0130, *In the Matter of Energy Storage Deployment Program,* has been created by DPS to maintain this public record and all documents and filings will be located in the Department's Document and Matter Management System, accessible at:
http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=55960.

The figure below provides a high-level timeline of the major milestones associated with the storage targets and deployment.

Figure ES4. High-Level Timeline of Anticipated New York State Storage-Related Milestones



DPS and NYSERDA Staff wish to thank the large number of stakeholders who engaged during the formative stages of the Acelerex energy storage study, contained in appendix G, and the development of this Roadmap. All stakeholders including developers, customers and interested parties are strongly encouraged to participate in the formalization of this Roadmap by offering input and additional recommendations and participating in the technical conferences.

1 Introduction

In January 2018, Governor Andrew M. Cuomo announced an initiative to deploy 1,500 megawatts (MW) of additional energy storage in New York State (NYS or "the State") by 2025. In doing so, he directed State energy agencies and authorities to work together during 2018 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.

Under Governor Cuomo's Reforming the Energy Vision (REV), New York is transforming its electricity system into one that is cleaner as well as more resilient and affordable. Energy storage technologies will play an increasingly important role in this transformation. Through lowering the cost and speeding the deployment at scale of storage solutions and drawing on innovation and investment from all sectors, energy storage will create the most value for customers and the state's energy system in the new energy paradigm. This nation-leading energy storage initiative builds upon and reinforces New York's commitment to undertaking bold efforts to address climate change, build an economy based on clean energy, and foster innovation.

This Roadmap, developed by the Staff of New York State Department of Public Service (DPS) and the New York State Energy Research and Development Authority (NYSERDA) (jointly "Staff") in conjunction with numerous stakeholders, develops an approach and a series of recommended actions that are intended to achieve the Governor's 1,500 MW target in a manner that reflects the principles underpinning REV:

- Improve the overall efficiency of the electric system by stimulating third-party investment alongside public and utility investment.
- Reveal and reward value – value that is frequently granular in time and location.
- Spur the pace of cost reductions by supporting markets at scale and promoting competition.
- Remove impediments, especially those relating to soft costs (e.g., permitting, interconnection, customer or site acquisition, data access to target the highest-need and most valuable locations), finance, and project bankability.

New York's electricity system is changing and is subject to evolving needs and stresses. Upgrading the state's generation and transmission and distribution (T&D) infrastructure is expected to cost roughly $30 billion over the next decade.[16] Renewable energy sources like wind and solar are producing a larger share of New York's electricity, requiring more sophisticated approaches to addressing intermittency. Beneficial electrification of transportation and heating will be key to achieving the state's climate goals but will place additional demands on the grid, further necessitating flexible solutions including storage. Energy storage technologies can play a valuable role in helping to address these and other demands of a rapidly changing electric sector.

Energy storage serves as a critical resource for enabling New York's clean energy future. As renewable power sources like wind and solar provide a larger portion of New York's electricity needs, storage will be used to smooth and time-shift renewable generation and minimize curtailment. As New York's grid becomes smarter and more decentralized, storage will be deployed to store and dispatch energy when and where it is most needed. Storage will also allow New York to meet its peak power needs without relying on its oldest and dirtiest peak generating plants, many of which are approaching the end of their useful lives. The numerous services that energy storage can provide can also be "stacked" and performed

[16] *See* 2015 New York State Energy Plan, available at: https://energyplan.ny.gov/-/media/nysenergyplan/2015-state-energy-plan.pdf.

either at the same time or with the same resource. This flexibility is especially important as the electric system evolves to become more decarbonized, decentralized, and complex.

Deploying 1,500 MW of energy storage by 2025 will bring a host of benefits for New York, including:[17]

- **Nearly $2 billion in gross lifetime benefits** to New York's utility customers, according to a state-sponsored analysis by the consulting firm Acelerex.[18]
- **Addition of flexible resources,** which will become more valuable as the state adds more renewable energy (both at small and large scales) and will enable these resources to meet periods of peak demand.
- **Avoiding more than one million tons of CO_2 emissions** over the life of the storage assets (estimated at 10 years). The carbon benefits from adding energy storage grow substantially as the state approaches higher levels of renewable generation that would otherwise be curtailed, especially at night; charging the storage with off-peak renewable energy to discharge and displace fossil generation during peak periods of demand will provide a substantial benefit to the state's carbon footprint and air quality.
- **Adding resiliency to the electric system by reducing the impact of outages.** For illustrative purposes, 1,500 MW of storage is the equivalent electric demand of one-fifth of all New York State homes.
- **Protecting public health by meeting many of the peaking needs currently served by older and higher-emitting fossil plants that may be close to retirement**, many of which typically reside in environmental justice areas. Off-peak charging reduces emissions of particulate matter and nitrogen oxides which are often more critical at times of peak electricity demand.
- Job creation on the order of **30,000 jobs in the storage sector by 2030**[19], as more and higher-skilled workers are called upon to meet growing demand and New York becomes a home for this rapidly expanding clean tech industry.

Energy storage is at the forefront of the dynamic changes occurring in New York's energy sector, from the conceptual reimagining of the state's electricity industry through the REV initiative, to the tangible infrastructure investments laid out in New York's Offshore Wind Master Plan,[20] to the State's ambitious renewable energy, greenhouse gas reduction and energy efficiency directives.

New York is on the cusp of unleashing the benefits of energy storage. Finding the most valuable, affordable and effective means of realizing those benefits is the central challenge at hand. This Roadmap identifies the most promising opportunities for doing so.

Current State of New York's Energy Storage Market and Growth Projections

Today, approximately **1,460 MW of energy storage** is deployed in New York. Almost all (97 percent) is pumped hydro at two New York Power Authority (NYPA) facilities comprising 1,400 MW of long-duration storage (approximately 10 hours). Additional installations include a 20 MW flywheel used for frequency regulation, customer-sited thermal storage (i.e., ice or chilled water) to reduce air conditioner load in large buildings during peak demand, and battery storage used for peak load management. Another 100 MW

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[17] *See* Appendices A-B for more details on the types of storage and its benefits.
[18] *See* Appendix L for the results from the Acelerex study.
[19] *See* Press Release, Governor Cuomo Unveils 20th Proposal of 2018 State of the State: New York's Clean Energy Jobs and Climate Agenda (January 2, 2018), https://www.governor.ny.gov/news/governor-cuomo-unveils-20th-proposal-2018-state-state-new-yorks-clean-energy-jobs-and-climate.
[20] *See* New York State Offshore Wind Master Plan, available at: https://www.nyserda.ny.gov/All-Programs/Programs/Offshore-Wind/New-York-Offshore-Wind-Master-Plan.

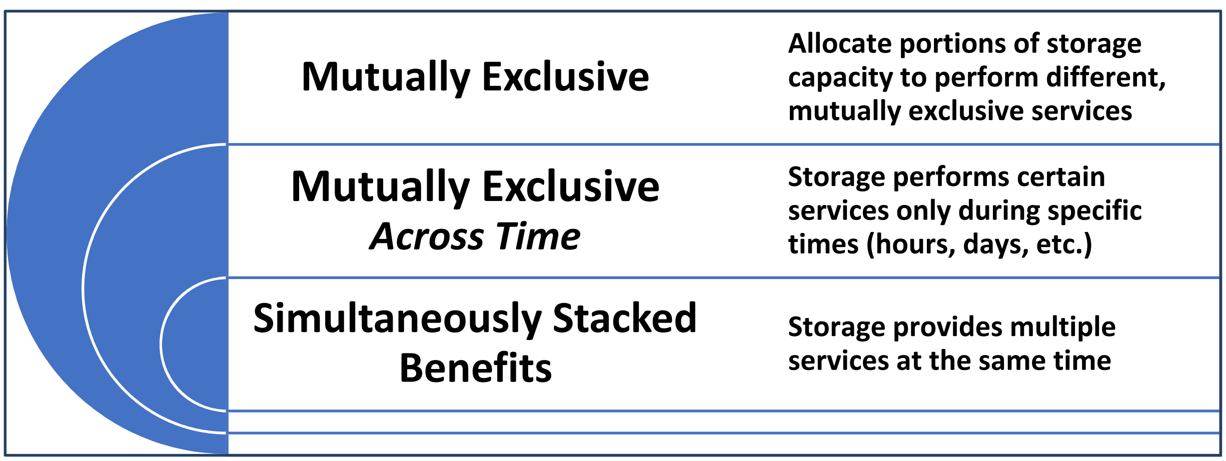
of storage is in various stages of development or permitting; almost 90 percent of these projects are lithium ion systems, which have benefitted from cost declines driven by electric vehicle production. These projects, which number several dozen, will be largely located in downstate New York, close to load pockets and the highest electric prices. Also, in the pipeline is another 430 MW from six potential battery storage projects, which are in "prospecting stages" within the NYISO queue and would provide capacity and ancillary services.

New York is one of the fastest-growing markets for energy storage due to a combination of its specific market and electric system needs and characteristics as well as its progressive policies. These factors will drive the local market while positioning the state to capitalize on larger industry trends such as continuing cost declines and technology innovation.

Applications of Energy Storage

Energy storage has been called the "Swiss Army knife" of the electricity system in recognition of the many services it can perform. Some of these services are mutually exclusive; others can be "stacked" and performed either at the same time or with the same resource. This flexibility is especially important as the electric system evolves to become more decarbonized, decentralized and complex.[21] Ultimately, the type, number and value of services that storage can provide are likely to change as the needs of the system change and storage technology advances. Generally, storage technologies cannot perform all services of which they are capable simultaneously, which creates a need for clear performance, dispatch, and control requirements and signals. Through the right system planning, dispatch and price signals, storage can provide customer-sited benefits, distribution system relief and wholesale services in the future.

Figure 5. How to Stack Value for Energy Storage?



Barriers to Energy Storage

A clear route to market exists today for only a limited number of storage services, and other services cannot be monetized in current electricity markets. Consequently, the benefits of some storage services

[21] This complexity will likely take the form of a system with two-way power flow characterized by more renewable, intermittent energy; increasing diversity of end-uses and customer preferences; beneficial electrification of the heating and transportation sectors; and need for increased system resiliency and lower costs to maintain a safe, affordable, and reliable electric system.

remain unrealized. This is especially true of services that can be stacked together, either at the same time or with the same resource over time. The primary challenges facing energy storage in New York include:

- **The inability to monetize the full value of storage**. Current restrictions and/or high costs from aggregation or telemetry that would enable monetizing multiple stacked services are one of the largest barriers with storage. This limits the value and therefore the economics and financeability of storage in today's electricity markets.
- **Limited routes to existing markets**. Regulatory and market rules, which were largely put in place before non-hydro storage as well DERs were available, often limit the ability of storage to receive compensation for the services and benefits it could provide. In some cases, these rules do not fully recognize the inherent value that near-instantaneous response can provide compared to alternative solutions.
- **Confidence in performance and lifetime**. The diversity and relative "newness" of different types of energy storage technologies, products, applications and use cases complicate understanding and confidence among potential customers and investors.
- **Lack of common financing vehicles**. The relatively low volume of existing energy storage projects contributes to a lack of standardized and transparent processes, procedures, and documentation, which impedes investor confidence and the ability to finance projects using traditional vehicles. This also increases the transaction cost of project finance.
- **High soft costs** related to permitting, siting, interconnection, customer acquisition and financing.
- **Insufficient data**, which impedes efforts to site storage as well as DERs for maximum system benefit and identify potential customers.
- **Storage costs** are still too high today to allow scale in many use cases, although costs have generally been declining by an average 10-15 percent per year. The proposed Roadmap actions seek to accelerate this trend by achieving significant reductions in soft costs and providing a near-term market acceleration bridge incentive.

Drivers for Energy Storage Including New York State Initiatives

New York's target to deploy 1,500 MW of energy storage by 2025 exists within a group of State policies and initiatives positioning New York as a leader on climate and energy, resilience and job creation. These include the requirement to obtain 50 percent of the State's electricity supply from renewable energy sources by 2030; the REV initiative; and Governor Cuomo's announcement in January 2018 that New York will procure 800 MW of offshore wind over the next two years in support of a 2030 offshore wind target of 2.4 GW. Moreover, New York is currently pursuing many different activities at both the retail and wholesale levels to create a favorable environment and cost-effective routes to market for a range of energy storage services and technologies.

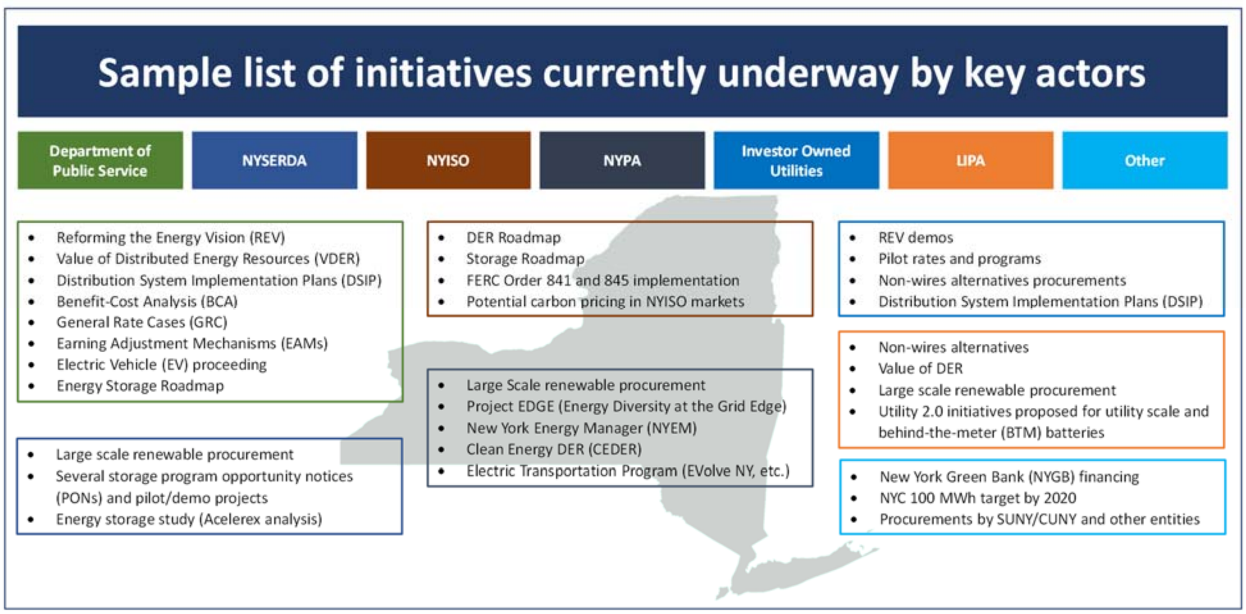
Some of the key factors driving storage adoption include:

- **Declining costs**, which are forecasted to continue through the early 2020s.
- **Better performance and longevity** of different storage technologies and applications.
- **Increasing investment appetite** among developers, customers and financiers.
- **Improved understanding of the value provided by renewable energy, DERs and other innovative technologies** as a result of several successful New York demonstration projects.
- **Municipal sustainability commitments including New York City's goal to deploy 100 MWh of storage by 2020**, the first citywide target of its kind in the U.S.

New York has also committed tremendous financial resources to clean energy, including a $5 billion Clean Energy Fund. This includes $60 million in funding for energy storage soft cost reduction, value stacking pilots and R&D. The Governor also announced in January 2018 that the New York Green Bank would invest a minimum of $200 million in energy storage projects to achieve greater financing scale in this sector. These commitments are in addition to the recommended market acceleration bridge incentive included in this Roadmap.

Further, New York State has undertaken a number of parallel and interlocking storage-related initiatives, as shown in the figure below. All support New York's goals to lead on environmental and energy technology policy, promote markets and innovation, and foster customer choice. Storage, as a versatile asset, is being considered in many different contexts. This contributes to soft and hard cost reductions; better understanding, quantification, and realization of the many potential values of storage; and ultimately, greater deployment.

Figure 6. Parallel and Interlocking Initiatives Involving Storage in New York State



2 Roadmap Approach

The Roadmap emphasizes implementable actions that can be undertaken immediately and during the next few years in order to build the future state that is envisioned.

The Roadmap organizes high-level storage deployment applications by grouping them into three market segments based on where the storage sits on the electric grid and the needs it addresses:

- **Customer-Sited**: Paired with on-site load and/or paired with DERs and located behind a customer's retail meter.
- **Distribution System**: Stand-alone or paired with DERs and connected directly on the distribution circuits.

- **<u>Bulk System</u>**: Stand-alone or paired with generator connected at the bulk or transmission system level.

2.1 Purpose

This Roadmap provides an analytically-driven set of recommended near-term policy, regulatory and programmatic actions to support energy storage deployment in New York State. It was developed in the context of barriers that could realistically be remedied on the path to reaching the Governor's ambitious 2025 energy storage target in anticipation of a larger 2030 storage deployment target.

The Roadmap focuses on near-term actions that will allow New York to deploy storage in ways that are viable, replicable and scalable by **focusing on those deployments that provide the most value to the system while minimizing overall costs to customers.** Accelerating storage deployment in the near term is important to reduce soft costs, increase confidence in storage as an electric system resource, and expand customer choice by increasing the number of developers selling solutions in New York State.

While a majority of the Roadmap's recommended actions relate to near-term implementation, others focus on more long-term, fundamental adjustments to market design. Where appropriate, nearer-term bridging mechanisms are identified. By developing detailed use cases, the Roadmap seeks to provide illustrative examples to system planners and the marketplace about cost-effective opportunities for energy storage to address current and future electric system needs. The Roadmap is informed by recent analysis performed by Acelerex, under contract with the State, which identified beneficial storage deployment opportunities as New York's electric system approaches 50 percent renewable generation and 40 percent carbon reduction by 2030, and also by general support and specific economic analysis conducted by Energy and Environmental Economics, Inc. (E3), also under contract with the State, examining how specific recommended actions affect project economics and bankability.

2.2 Process

The Roadmap's use case analysis occurs in the context of declining storage costs and ongoing market evolution at the wholesale and retail levels. It was informed by insights from a range of market participants including storage, DERs, and other vendors, system integrators, power producers, utilities, and the NYISO.

The Roadmap was developed using the following approach:

- **Engaging stakeholders** including customers, utilities, the NYISO and other market participants through working groups, conferences and individual meetings, and leveraging input already received through DPS working groups (including Value of DER (VDER) and rate design working groups).
- **Identifying and modeling storage use cases** reflecting a wide but not exhaustive range of potential installations.[22]
- **Recognizing key challenges** that must be addressed and actions that can be taken in the near and medium term.

[22] While many use cases were analyzed, the list was not exhaustive and certain use cases or specific projects will become economical sooner or later than what is indicated by the analysis depending on specific project economics and the cost decline curve. Storage technologies and the electricity system as a whole are evolving and innovating; additional use cases and applications may emerge over time that this Roadmap analysis did not envision or analyze.

- Conducting an **in-depth analysis** of each use case to analyze storage value; develop, inform and test potential actions; estimate market uptake; and develop implementation pathways.
- **Developing a set of recommended actions** to immediately begin transitioning the market toward a self-sustaining market that can respond to system needs and price signals and achieve maximum benefit for ratepayers.

2.3 Outputs

Beyond offering specific recommendations, the Roadmap clearly articulates the roles and responsibilities of each of the relevant entities involved in realizing and enabling storage value. It also specifies the entities needed to directly implement recommended actions, if appropriate. Briefly, the key actors and their expected primary roles can be summarized as follows:

Figure 7. The Roadmap's Key Actors and Expected Primary Roles

DPS/PSC	•Removing regulatory barriers, enabling retail and utility markets
NYSERDA	•Reducing soft costs, accelerating adoption to remove near-term barriers, accelerating financing at scale through the NYGB, facilitating a skilled workforce
Utilities including LIPA	•Procuring through NWAs, load management, interconnection, integration, dual market participation
NYPA	•Procurement, financing and first mover in strategic storage projects across NYPA assets and customer sites
NYISO / Utilities / DPS	•Market integration, optimization/dispatch services, planning, interconnection, dual market participation
Developers / Technology Providers	•Spurring cost declines, innovation, communication / control technologies, end of life reuse or recycling
3rd Parties / Aggregators	•Financing, development, economies of scale, market access
Financiers / Investors	•Debt/equity financing, risk management, alternative business models, wholesale / retail hedging products
Customers	•Hosting, choice, resiliency, financing
Other, including Local Municipalities, DEC	•Siting and permitting, environmental evaluations

3 Key Analytical Findings

The Roadmap's analytical framework is grounded in the economics and value proposition of energy storage. Developing this framework involved first examining the costs of energy storage technologies and then comparing those costs with potential future value streams[23] for specific use cases and operations, financing and business models.

The **customer-sited** use cases examined storage applications for customer retail bill management and demand response within eight illustrative commercial, industrial or municipal customer types – selected based on their greater consistency with other customers' load shapes to examine the potential market impact from the recommended actions. Residential customers could also site storage, for instance when paired with PV. **Distribution system** use cases analyzed VDER tariff compensation for electricity exported into the distribution system, NWAs with wholesale market participation, and PV paired with energy storage cases. **Bulk system** use cases analyzed combinations of wholesale market services including energy arbitrage, capacity, spinning reserves and frequency regulation, high zonal congestion energy prices, and large scale renewables paired with energy storage. Dual market participation in which storage met distribution and wholesale system needs was examined. Project modeling was done in several utility territories and NYISO zones to provide a range of values.

Because an individual storage project's value proposition hinges on multiple potential value streams, value stacking is essential. However, since not all values can be realized today, and some may not evolve or be accessible until the future, this presents current a significant barrier to unlocking the full potential of energy storage. Thus, the Roadmap's recommended actions aim to enable the realization of storage value, now and over time, and to reduce barriers and costs.

The upfront **breakeven installed cost of storage (BICOS)** is the primary analytical metric used in this Roadmap. BICOS indicates what the total upfront cost of storage must be for a project to be economically feasible, defined as the project benefits or values exactly equaling all costs to install, commission, finance and provide a return on the project over its life.[24] The higher the BICOS, the better the project's economics and the closer it is to commercial viability today based on current installed cost. This metric was useful given the range of storage technologies and current costs. Several important conclusions emerge from this analysis about how soon use cases become economical based on an assumed cost decline forecast. The figure below summarizes the BICOS results across a number of diverse use cases.

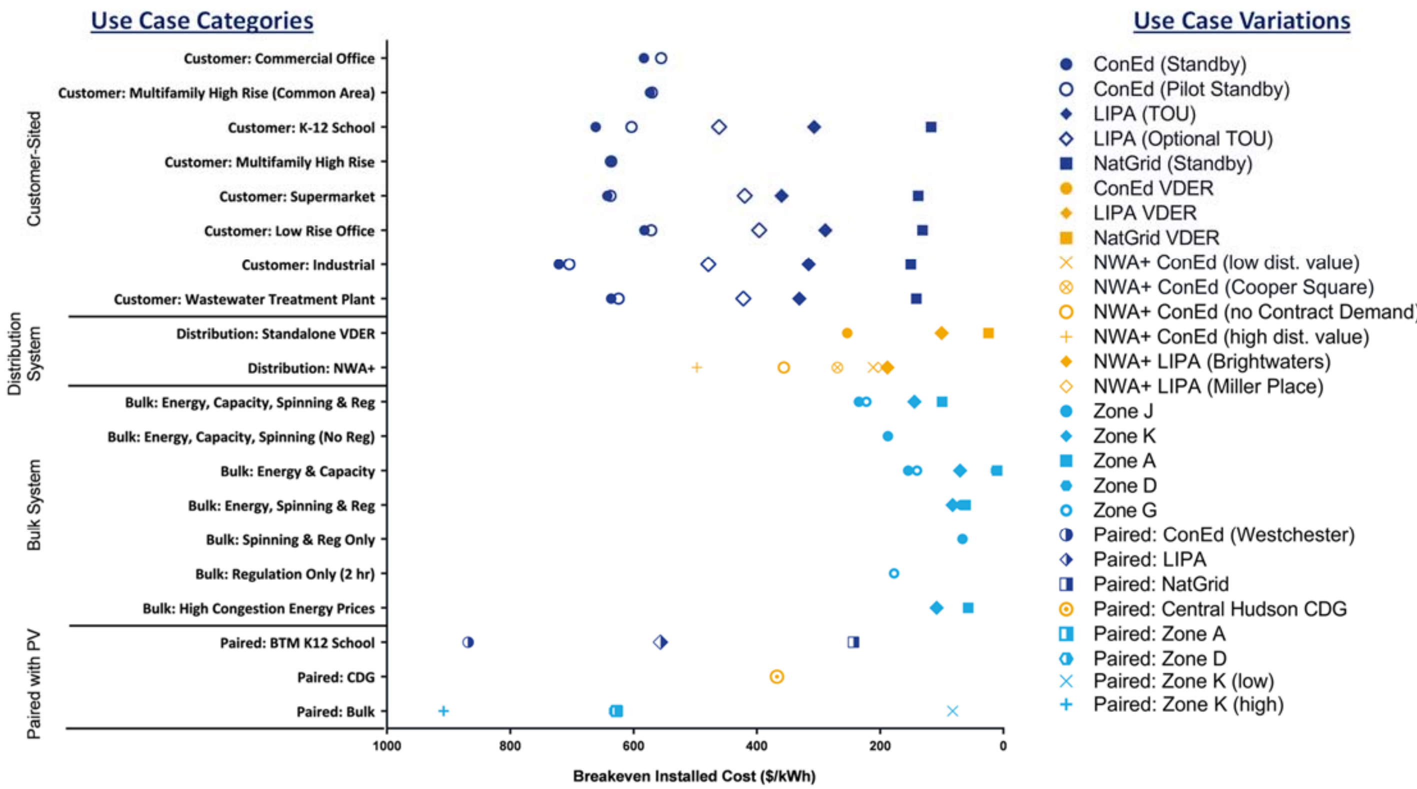
As shown in the figure below, the Roadmap modeled many different use cases and found that the BICOS varies widely for different use case types and configurations. Several important conclusions emerge from this analysis about how soon use cases become economical based on an assumed cost decline forecast. In general, **many customer-sited and distribution system use cases and paired solar + storage projects are or will soon become viable in downstate New York between now and 2025**. This is due to better project economics, where higher value streams offset higher costs. Economically attractive opportunities to pair storage with renewables and potentially to hybridize and/or replace fossil peaking units will begin to arise as will high-value distribution system use cases in upstate New York. In the longer term, numerous diverse use cases will become economic across New York, especially as the system adds more renewables and the cost of storage solutions continues to decline. Importantly, there will also be cases in which

[23] In this report, "value streams," "benefits," and "revenues" are all synonymous and used interchangeably.

[24] The BICOS metric is not a levelized number itself, but it is calculated based on a project's levelized costs and benefits in order to determine the total upfront installed cost of storage that results in the levelized costs exactly equaling the levelized benefits.

project economics far surpass the illustrative economics shown due to differences in load profiles and locational needs.

Figure 8. Economics (BICOS) of Various Storage Use Cases Comparing Revenue Streams to Total Cost Over System Lifetime[25]



For more information on the Roadmap analytical approach and details on the assumptions as well as an expanded set of results please see Appendices B-F.

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[25] All stand-alone use cases were considered over a 10-year asset life inclusive of all costs including Operations and Maintenance. All paired cases considered were over a 25-year asset life inclusive of all costs including Repairs and Replacement and Operations and Maintenance.

Customer Assumptions: Storage sized at 10% of the customer's peak load for 4-hour duration. Discharge compensation is bill savings and DR revenues. Third party financed: 60% equity at 12% and 40% debt at 7% for a 9.3% WACC & discount rate. DR revenue considered for 10 years. 15% de-rate applied to revenues to reflect real world scenario without perfect foresight.

VDER Assumptions: Storage sized at 1 MW 4 hour. Discharge compensation at VDER stack (LBMP, ICAP, DRV value lock for 7-years), charging at LBMP + Contract Demand. Third party financed: 100% equity at 12% WACC & 12% discount rate. 10% de-rate applied to revenues to reflect real world scenario without perfect foresight.

NWA+ Assumptions: Storage sized at 5% of substation peak load, 6-hour duration. Discharge compensation at estimated NWA value (DRV + LSRV), LBMP arbitrage, ICAP & spinning reserves; charging at contract demand + LBMP. Third party financed: 50% equity at 12% and 50% debt at 6% for an 8.2% WACC & discount rate. 10% de-rate applied to wholesale revenues to reflect real world scenario without perfect foresight. "No Contract Demand" charge is shown for Cooper Square with utility financing (48% Equity at 9% and 52% Debt at 4.74% for a 6.73% WACC & discount rate). High and low distribution values are shown for the Cooper Square illustrative example to reflect a range of potential NWA compensation.

Bulk Assumptions: Third party financed: 60% equity at 12% and 40% debt at 7% for a 9.3% WACC & discount rate. 10% de-rate applied to all revenues to reflect real world scenario without perfect foresight.

3.1 Customer-Sited Key Takeaways

The customer-sited use case analysis shows that **value stacking will be critical** for certain customers. While several factors determine the economics of customer-sited cases, the biggest drivers include the customer's "peakiness" (ratio of peak to average electric load), demand charge cost, desire for resiliency, and ability to access additional revenue streams. Specific takeaways informing Roadmap actions for customer-sited storage deployment are as follows:

- **Individual load shapes determine how much bill savings benefit customers will realize**. Higher benefits are realized if a customer's peak demand overlaps with the time period of peak charges; is short enough that the storage can flatten this peak; and is high enough that the customer would otherwise see a high demand charge. Customers with longer and flatter load shapes will capture lower benefits.
- Due to Con Edison's relatively high demand charges and Demand Response (DR) program compensation, **Con Edison customers are the best candidates for near-term deployment of storage**. The Standby Pilot Rider Q[26] economics, which assign a sub-daily demand charge, are comparable to the existing standby rates at smaller energy storage sizes but offer potentially much higher savings at larger sizes.[27]
- **Determining whether a customer will be a good candidate for energy storage is complex,** given the diversity and variability of load shapes and uncertainty around future rate and demand response program levels. Increased access to customer data could reduce the costs of customer acquisition and project analysis for customers and third-party developers.
- In general, **most customer-sited use cases are not economic under today's costs when accounting for revenue uncertainty and financing risk**. However, targeted actions can address these barriers and help catalyze deployment. **Reducing installation and financing costs and/or developing a bridge incentive** can make projects more economical in the near-term and accelerate the cost decline curve.
- Stress testing shows that **revenue certainty is important**, especially for financing and the ability to realize certain values over time.
- Pairing solar PV with storage can increase value by managing PV system output and provide cost savings due to the availability of investment tax credits for paired systems. Limiting the amount of exported electricity may also reduce interconnection costs.
- Storage can help manage EV charging load and limit impacts on demand bills.
- Microgrid applications are interesting and have potentially attractive economics. NY Prize is leading development of microgrids throughout New York State, which will help to provide specific operating and business models that yield the strongest economics and benefits.
- Residential storage (whether paired with solar PV or not) can be used to respond to more dynamic "smart rates" like Con Edison's Smart Home Rate.[28] As these optional smart rates become more prevalent, the economics of this use case will continue to improve.

[26] Only Option B was modeled. *See* Standby Pilot Rate Program (Rider Q) Tariff, available at: https://www.coned.com/en/save-money/using-private-generation-energy-sources/private-generation-tariffs.

[27] It is important to note that only eight specific load shapes were modeled in this analysis, and while results provide insight as to how customer types will benefit from storage they are not indicative of how all like customers will perform.

[28] *See* Case 14-M-0101, Smart Home Rate Demonstration Project Concept, available at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B2F247C08-2258-4C39-A84C-CEBF1F4405B7%7D.

- The **Roadmap actions for customer-sited deployment strike a balance** between providing revenue certainty for customers and maintaining dynamic price signals that reflect system needs so the grid benefits from storage.

3.2 Distribution System Key Takeaways

The distribution system use case analysis shows that **value stacking will be critical**. Modeling shows financially viable opportunities to pair storage with solar and to meet high-value non-wires alternatives with wholesale market participation (referred to as "NWA+")[29] that utilities are procuring to defer or avoid traditional capital investments. In some cases, stand-alone VDER participation may be possible, but this will vary by individual project. The specific insights from project analytics that inform the Roadmap's actions for distribution system storage deployment are as follows:

- **Value stacking** is critical to maximize system benefits and improve project economics. Access to distribution and wholesale system markets also diversifies revenues for developers. Various business models can be constructed around these markets, including developer/utility shared savings models.
- **"Dual market" or multiple market participation (retail and wholesale) must be developed to maximize ratepayer benefits from storage as well as DERs.** Participation rules need to be defined so that they recognize and strike a balance between reserving priority access and maximizing value streams (since the more restrictive those requirements, the less economic those projects become).
- **Charging costs affect storage operations and the potential value of the asset, especially when it participates in multiple markets.** For example, in the illustrative analysis a flat contract demand charge was applied which dampened the potential energy arbitrage value in order to minimize spikes in charging (which would increase the contract demand charge). Existing tariffs that govern grid access fees may not align with intended outcomes from NWA procurements (e.g., higher demand charges can result from maximizing export during peak hours vs. lower demand charges if assigned based on off-peak charging at a lower power rating).
- **NWAs will vary significantly** in their costs for charging and interconnection. Similarly, the underlying distribution value will vary by project, type of load relief requested and location. Value stacking will be key to making these use cases economic and the rules around dual market participation and ability to monetize distribution and bulk system values will be critical (i.e., expanded or NWA+ projects). Efforts to pursue broader ratepayer benefits by reducing the overall size of the utility's full-service customers' bills in NWAs should be pursued.
- Improved **access to distribution system data** would help developers plan and site distribution-system storage more effectively, given how locational and specific these values are.
- **Increased revenue certainty under NWA+ contracts** would allow for lower-cost financing. The term of NWA contracts should be made more easily extendable. In the event that an NWA is not extended to the life of the asset, **non-distribution values** (e.g., bulk system values of energy, capacity, and reserves) **should remain accessible and potentially valued in an NWA+ contract**, to the extent possible, in order to reflect the total lifetime value of the storage asset.

[29] NWA+ represents use cases with distribution T&D deferral value in addition to reducing the single peak hour resulting in capacity savings and providing wholesale market revenues.

3.3 Bulk System Key Takeaways

Value stacking will also be critical for projects to break even at the bulk level, which has fewer potential value streams as compared to the distribution and customer-sited levels. Opportunities for pairing storage with solar and other renewables will emerge over time. Storage could also replace or augment portions of the existing peaking fleet as units retire based on economics, although further analysis is needed to determine how best to accomplish this while maintaining reliability and contingency requirements. The specific takeaways informing the Roadmap's actions for bulk system storage deployment are as follows:

- As noted above, **rules for "dual market" participation must be accelerated** to realize the full potential of storage to meet system needs and yield ratepayer benefits, as envisioned by FERC Order 841.[30]
- Specific use cases in the bulk system may be attractive in the near term. Broadly replicating and scaling these will require considering the **unique attributes** of storage, especially its near-instantaneous response. Rules around aggregation, telemetry and metering must also evolve.
- **Storage is well suited to help address many of the system peaking needs provided by older and higher-emitting fossil units**. It can also increase efficiency of these units when paired. Many peakers are at (or past) their useful lives, and costly emission controls and capital upgrades may be better invested in new technology. Modifying reliability rules, which mandate indefinite run times and do not consider today's DER and automated load management solutions, would enhance storage's ability to meet system peaking needs.
- **Paired solar + storage deployments are attractive** given the ability of projects to firm solar production, receive the associated Federal Investment Tax Credit benefits, and potentially reduce interconnection costs by limiting power output.
- Finally, **storage opens a large new market for off-peak charging** from both renewable generation and traditional generation.

3.4 Market Sizing

2025

The Roadmap includes a **market sizing** estimate to illustrate one plausible storage deployment scenario for achieving New York State's 1,500 MW target by 2025. The Roadmap's market sizing breakdown examined specific market segments within the three larger storage application categories (i.e., customer, distribution and bulk) and was informed by the use case analytics, the expected decline of energy storage costs over time, and the successful adoption of the actions recommended in this Roadmap. **The size of each respective market segment approximately equated to 500 MW of deployment by 2025**. While the segments examined in this market sizing exercise are broad and inclusive of a number of diverse use cases, there are many other potential and reasonable deployment scenarios that could be constructed, as well as other market segments that may not be fully or accurately characterized in this particular exercise. This scenario was informed by the project economics and market sizing estimates that E3 prepared and the Acelerex energy storage study and reflects one path for reaching 1,500 MW by 2025.

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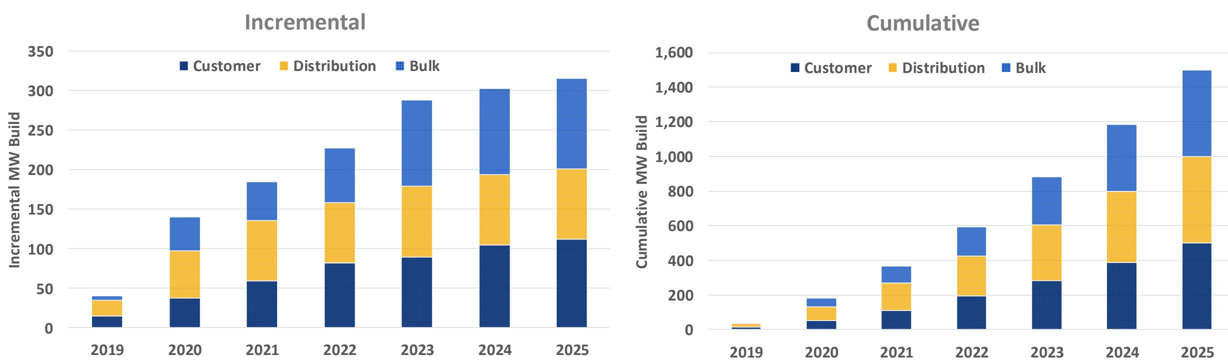
[30] FERC Order 841 requires each RTO and ISO to revise its tariff to establish a participation model consisting of market rules that, recognizing their physical and operational characteristics of electric storage resources, facilitates their participation in the RTO/ISO markets. The ability to simultaneously provide distribution-level and wholesale-level services is an operational characteristic that should be addressed in the NYISO's compliance tariff filing.

The market sizing shows storage deployment gradually increasing over the near-term as the market is accelerated via adoption of the Roadmap's recommended actions. This intentionally avoids a "J-curve" deployment scenario (i.e., where most storage is installed closer to 2025) because a late-deployment trajectory may not achieve the 2025 goal (since in that case the New York State market may not have evolved sufficiently to accommodate such a concentrated level of deployment). Due to assumed value stacking, many customer-sited and distribution system storage resources will likely provide value to the bulk system as well.

Figure 9. Deployment Scenario Resulting in 1,500 MW of Storage by 2025



In this scenario, **customer-sited storage and paired on-site generation + storage including PV** is estimated to comprise 500 MW by 2025. This estimate is based partially on the use case analytics to determine good-fit customers for storage as well as the size of the overall potential market in various utility territories[31] (with a focus on New York City, Westchester and Long Island since use case economics were found to be stronger in those locations). It is important to note that there are a number of different use cases embedded in this category including microgrids, electric vehicle charging management, and others. Residential solar + storage is also included in this segment.

The **distribution system segment** is estimated to comprise 500 MW by 2025 under the examined scenario. This includes expanded non-wires alternatives (referred to as "NWA+"), community distributed generation (CDG) + storage, and wayside storage to utilize regenerative braking[32] 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.

Finally, the **bulk system segment** is estimated to comprise 500 MW[33] by 2025 under this scenario and 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[34],

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[31] This does not reflect total addressable market as it is only informed by the number of customers in the limited number of load profiles that were examined.

[32] *See* Feasibility Study of On-Car Regenerative Braking System (RBS) for Electric Rail Applications (January 11, 2013), available at: https://www.nyserda.ny.gov/-/media/Files/Publications/Research/Transportation/feasibility-on-car-regenerative-electric-rail-applications.pdf.

[33] Note that due to assumed value stacking, many customer-sited and distribution system storage resources will likely provide value to the bulk system.

[34] Hybridization involves installing storage at an existing conventional site that can either be charged from the on-site generating unit or enhance the operations of the existing conventional unit(s) (allow it to operate at a higher efficiency, more flexibility in minimum generating requirements, faster ramping, and/or ability to participate in certain ancillary services markets like regulation or 10-minute sync).

replacement[35], or repowering.[36] Analysis examined the approximately 3,000 MW downstate peaker fleet to identify the proportion of units that could reasonably be hybridized to enhance their value and/or provide a transition path toward retirement and replacement without threatening reliability. The analysis also estimated the amount of peaker replacement that could occur given today's NYISO and utility planning and operating paradigms.[37] Multiple factors, including the evolution of wholesale market storage products (e.g., the development of a fast-ramping product) could increase deployment beyond estimated levels.

2030

The New York State market for energy storage, while still in its early stages, is expected to accelerate rapidly as the actions in this Roadmap are implemented. Energy storage technologies, costs, and global market forces continue to evolve. Therefore, an equivalent market sizing by segment was not developed for 2030. Instead, the Roadmap utilizes analysis performed by Acelerex for its longer-term 2030 potential market sizing estimate.

The Acelerex analysis showed that the deployment of 2,800-3,600 MW of energy storage by 2030 results in over $3 billion in gross ratepayer benefits.[38] 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. This analysis utilized the best-available system mapping, which was nonetheless limited in its distribution system detail, and consequently this analysis neither reflects an upper bound on ratepayer benefit[39] nor maximizes the amount of storage that can be deployed in the State.

4 Recommended Actions

The approach taken in this Roadmap is to develop rates, rules, and program designs that enable all potentially valuable technology or resource types to participate effectively in the market by purposefully and specifically addressing barriers that impede the technology or resource types. This will allow for technology-agnostic competition among technology (or technology-combination) solutions to achieve the best value for the system based on cost, value, functionality and timing. The near- and medium-term recommendations are based on the key analytical findings, initial input received from stakeholders, staff and consultant analysis, and with the following context in mind:

- Recognition of the key barriers and challenges currently facing, or expected to confront, storage deployment in the near-to-mid-term (2019-2025) with an eye toward bridging mechanisms and near-term actions that can improve project economics by sending the most reasonable performance and price signals to the marketplace.

[35] This involves retiring the generating units/facilities and replacing with energy storage at a different site.
[36] Repowering is the process of replacing older generating units/facilities with newer ones at the same site that are either more efficient, increase the power generated, or involve energy storage and/or renewables.
[37] See Appendix H for more details on the peaker analysis.
[38] *See* Appendix K.
[39] Additional benefits from transmission deferral and reliability are not included, because the Acelerex study utilized a fixed transmission model. As a conservative assumption, hard limits were placed on the amount of storage that could provide ancillary services (25%) and in zonal capacity (10%) in the base case (these were adjusted to 50% and 15% in the peaker sensitivity). Loss of load expectation was also not considered in the peaker sensitivity.

- Achieving the longer-term (2026-2030) storage deployment targets and a self-sustaining marketplace requires building toward an end-state that includes full dual market participation (retail and wholesale services), customer load control, and dispatchable resources within the customer-sited, distribution system and bulk system set of storage applications.

The specific actions are grouped into the following seven general categories:

- **Retail Rate Actions and Utility Programs**. Improve customer retail delivery rates and programs like utility dynamic load management programs to send more accurate price signals that correspond to the system-wide and locational value of peak load reductions and to reduce financing barriers.
- **Investor-Owned Utility Roles.** Enable development of a market-based storage sector and align utility incentives to that end by clarifying the role and business model for IOUs to manage the full customer bill, leveraging assets such as storage and expanded NWAs (NWA+), where third-party assets provide utility T&D deferral, reduce generation capacity obligations by reducing peak system load, and provide ancillary services to the wholesale market.
- **Direct Procurement Approaches through NWAs, RECs and NYS Leading by Example**. Expand the market by employing direct procurement approaches through utility NWAs, NYSERDA's Renewable Energy Certificates (RECs) that can pair large-scale renewables with energy storage, and NYS "Lead by Example" procurement initiatives.
- **Market Acceleration Incentive.** Utilize market acceleration bridge incentives to hasten the market learning curve and reduce costs.
- **Address Soft Costs including Barriers in Data and Finance.** Pursue cross-cutting actions to reduce barriers including expanding access to more granular system load data to target highest-need locations on the electric system, lowering costs (e.g., permitting, interconnection, and capital costs), and ensuring access to a skilled workforce.
- **"Clean Peak" Actions.** Align storage approaches with Department of Environmental Conservation (DEC) draft combustion turbine peaking unit regulations and develop approaches to differentially value peak carbon reductions. This includes implementing "Clean Peak" actions through rate design, the market acceleration bridge incentive, REC procurements and a to-be-developed methodology for analyzing peaker plant operational and emission profiles on a unit-by-unit basis to determine best potential candidates for hybridization, repowering or replacement by storage.
- **Wholesale Market Actions and Distribution / Wholesale Market Coordination.** Develop approaches to directly or indirectly access wholesale market values (including capacity and ancillary service values) by modifying wholesale market rules to better enable storage participation, including dual market participation (i.e., where storage simultaneously provides both distribution system and wholesale system services) in compliance with FERC Order 841.

4.1 Retail Rate Actions and Utility Programs

4.1.1 Delivery Service Rate Design

Background

The current rates for retail delivery services for customers that install behind-the-meter (BTM) distributed generation are the standby rates in place at each utility. These rates reflect the design approach of recovering those costs of the system that are "local" through a contract demand charge and those costs that are "shared" through the daily as-used demand charges. As we continue to move toward a system of increased DERs at the distribution level, it is reasonable to revise delivery rates to more accurately reflect how costs are incurred by the utility to serve load. By sending more accurate price signals, DERs can be sited and operated in the most efficient manner to maximize benefits to all. As described in the analytics section, the application of a more granular daily as-used demand charge can provide an additional opportunity for DERs, like storage, to reduce peak demand and thereby reduce electric system costs borne by ratepayers.

Recommendations

Utilities should develop an optional rate, built on the current standby rate, that implements a more granular time- and location-varying daily as-used demand rate (similar to Con Edison's "Rider Q" pilot tariff) and include rate certainty during this pilot tariff period (e.g., Con Edison's Rider Q includes a 10-year rate fix). This is a stepwise policy action under REV that makes the economics for storage better in many cases and would better align price signals with system peaks to provide maximum ratepayer and system benefits. This tariff should serve as an opt-in rate for any demand-metered customer. 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. Staff recommends the maximum MW enrollment limit be set for each utility based on a non-participating customer bill impact under various opt-in scenarios. In addition, opt-in rules should be developed, and implementation should be standardized across utilities to the extent possible. Staff is interested in stakeholder feedback on the details of this approach and the bill impact percentage and parameters that should be applied by the Commission.

Path Forward

- Issuance of a DPS staff whitepaper on standby rate design that incorporates the recommendations above, followed by Commission action in 2018.

4.1.2 Commodity and Delivery Costs for Storage Charging and Discharging

Background

Unlike other types of DERs that respond directly to price (e.g., Wi-Fi thermostats enrolled in DR) or produce electricity, energy storage systems must first store the electricity (charge) before injecting into the grid (discharge). Rules for charging and discharging must be re-examined so that desired grid benefits are encouraged (e.g., off-peak charging and injecting electrons or reducing load on-peak). Limiting energy storage systems from engaging in uneconomic retail rate arbitrage was examined but may be mitigated by the differences between peak and off-peak pricing. The appropriate application of delivery service costs for discharging energy storage must also be addressed. These issues are applicable for storage systems that are used in behind-the-meter, distribution or bulk system applications.

Recommendations

As discussed in the recent DPS Staff whitepaper on value stack eligibility expansion,[40] in order for a customer with a stand-alone storage system to be eligible for VDER injection compensation, that customer should be charged for consumption at the utility's Mandatory Hourly Price (MHP) so that charges and credits both accurately reflect hourly values. The whitepaper also recommends that standby and buyback delivery rates apply for charging and discharge, respectively. In practice, this would result in the calculation of a contract demand charge that is the larger of the peak MW exported or the peak MW

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[40] *See* Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources, Staff Proposal on Value Stack Eligibility Expansion (filed May 22, 2018).

consumed. The impacts and outcomes of this approach, as well as various details such as the application of other taxes and fees, need to be examined in the context of the various storage use cases examined in this Roadmap. 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. More information is needed in order to establish the applicable rules, and Staff is interested in stakeholder input on the most appropriate manner to calculate contract demand or grid access fees.

- Commission action in 2018 on the DPS Staff whitepaper on value stack eligibility expansion, incorporating the recommendations above.
- Stakeholder feedback on the appropriate application and implementation of retail commodity and delivery tariffs for energy storage resources providing retail services (BTM and NWA+), and on wholesale charging and discharging to provide bulk services to the NYISO. The Commission should consider feedback in its development of a storage Roadmap order in 2018.

4.1.3 Value Stack (VDER)

Background

The Commission adopted the VDER value stack tariff in its order dated March 9, 2017.[41] The tariff applies to technologies and project types that had previously been eligible for net energy metering based on Public Service Law Sections 66-j and 66-l, as well as projects that paired energy storage with an eligible technology. The Order also required that the VDER tariffs be expanded beyond net-energy metering (NEM)-eligible distributed generation (DG) technologies to all DERs in a technology-neutral, value-focused manner as soon as practicable. The Commission also recognized that further refinement of the value stack components should be examined in Phase 2 of the VDER proceeding.

Recommendations

As discussed in the recent DPS Staff whitepaper on value stack eligibility expansion, the VDER value stack should be expanded to standalone storage (i.e., storage that is not paired with generation). This will enable several of the use cases examined in this Roadmap. In addition, analytics suggest that expanding the Distribution Relief Value (DRV) rate lock from 3 years to 7 years could reduce financing costs, thereby improving project economics, while minimizing ratepayer exposure. All stakeholders consulted by Staff, including the utilities, acknowledged that DRV continues to exist beyond the current 3-year term. The reality, however, is that financiers are considering this value close to $0 after the 3-year term since today's rate lock provides no assurance that the value will continue at or near the current level. To further enable DERs to provide distribution value on a consistent basis, utilities should establish a DRV call signal for top utility system hours similar to the existing Commercial System Relief Program (CSRP) program call signal which provides 21-hour notice before a forecasted event in which the system nears 90 percent of its rated capacity. Staff recommends that the utilities examine whether utilizing this CSRP call signal achieves the necessary purpose without the need to create any additional signal. This signal would provide interested developers with advance notice of likely DRV hours. Staff also recommends future examination of the best mechanisms of substantiating the value of distribution relief for DRV; currently this is developed from Marginal Cost of Service (MCOS) studies. Finally, Staff recommends continuing to include Locational System Relief Value (LSRV) within the value stack for the time being, but recommends that LSRV be best

[41] *See* Case 15-E-0751 et al., Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017).

considered within expanding NWAs to provide contracted relief to the utility with a higher degree of certainty for system planning purposes and greater revenue tenor than a rate design can provide.

Path Forward

- Commission action in 2018 on the DPS Staff whitepaper on value stack eligibility expansion that incorporates the recommendations above.
- Issuance of and Commission action in 2018 on DPS Staff whitepaper on DRV/LSRV that incorporates the recommendations above to address the marginal cost of service studies, the setting of DRV, DRV call signals and the future application of the LSRV.

4.1.4 Carbon Reduction Benefits and Shaping the E Value in the VDER Value Stack

Background

The greenhouse gas (GHG) or carbon impact of energy storage is highly dependent on three main factors:

1. The carbon emissions from the generator(s) that charge the energy storage, or the marginal generator at the time of charging if charging from the grid
2. The carbon emissions of the displaced marginal generator(s) when the storage discharges
3. The "round-trip efficiency" and "parasitic" losses of energy storage, which refer to the energy losses associated with charging, discharging and maintaining charge

The overall impact and value of reducing carbon emissions under current system conditions is reasonably well understood in the electric, heating, transportation, and agriculture sectors of the economy. It is not well settled how to best quantify and value the future environmental benefits associated with energy storage as the electric system changes due to beneficial electrification from heating, cooling and transportation as well as increasing renewables penetration.

Analysis presented in the Roadmap considers the carbon benefits from energy storage as the delta between the marginal emission rate when storage charges and discharges (usually set today by a fossil fuel generating unit).[42] As more renewables are added onto the system, energy storage will have a greater role in avoiding renewable curtailment, especially during off-peak periods and time shifting zero emission renewable energy to times that displace fossil fuel generation. Both activities reduce carbon emissions.

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. But the hourly Marginal Emission Rates (MER) data on which this analysis is based does not capture all of the nuances associated with individual generator profiles or sub-hourly emissions. Carbon reductions are expected to increase over time as more renewables are added to the system, which will increase the value of time-shifting energy.

For instance, a 1 MW, 4-hour storage unit charged from grid power during off-peak hours and discharged during peak hours today results in 100-200 tons of CO_2 reduced annually when operating the storage to maximize carbon benefits (based on 2015-2016 Marginal Emission Rates). By 2030, this could increase by a factor of three to over 600 tons annually (equivalent to the annual emissions of 120 cars) if storage were

[42] *See* Appendix G for more detail on Shaped Environmental Value analysis.

discharged to maximize carbon reduction, based on MER analysis by E3, LBNL[43] and the Acelerex energy storage study.

The Acelerex study determined that 2,800 MW of energy storage deployed by 2030 could reduce carbon emissions by two million metric tons over the life of the storage assets, equivalent to the emissions of 400,000 cars in a year. This study sought to optimize the grid services performed by the storage assets without regard to maximizing carbon benefits, and there is potential that this estimation could be considered a lower range.

This section discusses a structure for realizing and monetizing a carbon value that increases over time. Currently, the VDER E Value[44] is fixed or flat throughout the year under the VDER tariff, providing a per-kWh value to qualified injections. Consequently, this E Value is only an approximation of the actual carbon intensity of the grid, which varies on hourly, daily, seasonal and multi-year time scales.

Changes in energy demand and generation only affect energy sources that are economically "at the margin" based on their generation costs. Since the marginal source of generation varies as a function of energy demand across time and location, a more accurate way to account for the carbon emission impact is to use the MER associated with the marginal generator. The ideal method for estimating MER would be to identify, on an hourly or even sub-hourly basis, precisely which power plants on the grid respond to a change in energy demand. In practice, this is currently almost impossible and so a reasonable proxy must be used.

It is important to establish an E Value that is stable over time in order to encourage long-term investment in capital-intensive resources that reduce carbon emissions. At the same time, it is also important that the E Value be dynamic in order to reflect actual system conditions and maximize carbon reduction benefits.

The first step in determining how best to shape or differentiate the currently-flat E Value in VDER is to analyze the MERs of the NYISO system. Analysis was performed, based on work the NYISO has commissioned as part of the Integrating Public Policy Task Force (IPPTF), to calculate the historic hourly MERs of the NYISO system on a zonal basis for 2015 and 2016.[45] For completeness, E3 also performed a similar MER analysis based on publicly available data and found that the results aligned with the NYISO-commissioned study. The hourly MERs from the NYISO were used to transform the existing flat E Value (currently $27.41/MWh) into an hourly E Value to examine the effects of various approaches to E Value

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[43] *See* Seel, Mills and Wiser, *Impacts of High Variable Renewable Energy Futures on Wholesale Electricity Prices, and on Electric-Sector Decision Making*, BERKELEY LAB ELECTRICITY MARKETS & POLICY GROUP (May 2018), available at: https://emp.lbl.gov/publications/impacts-high-variable-renewable.

[44] The E Value is calculated as the higher Tier 1 Renewable Energy Certificates (RECs) under the Clean Energy Standard (CES) or the Social Cost of Carbon (SCC), net of the expected Regional Greenhouse Gas Initiative (RGGI) allowance values. The E value was originally set at $24.24/MWh based on the then-most recent Tier 1 REC procurement. The current Tier 1 REC pricing is $21.71/MWh – lower than the SCC-RGGI value of $27.41/MWh – so the current 'E' value is $27.41. *See* Case 15-E-0751, Staff Letter (March 28, 2018) available at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={CBEA125B-1D23-4D90-B893-B1A7BFD5B462}. *See* also, Case 15-E-0751, Staff Letter (March 13, 2018) available at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={3E9D8A11-23BF-49A8-97C1-533EC3A8A312}.

[45] See Calculation of Hourly MERs for 2017 Customer Cost Impact Analysis Memorandum to New York ISO, from the Brattle Group (March 7, 2018), available at: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg_ipptf/meeting_materials/2018-03-19/Calculation%20of%20Hourly%20MERs%20for%202017%20Customer%20Cost%20Impact%20Analysis%2020180308%20FOR%20POSTING.pdf.

shaping. These shaped E Values were then used to examine the potential effects on energy storage operations and credits under VDER for both stand-alone storage and solar + storage.

The following heat map shows hourly MERs and E Values averaged (simple, unweighted average) across each hour of the year for each month on a statewide basis (using average 2015-16 MERs), where the average MER across the year equals 0.506 short tons per MWh:

Figure 10. Marginal Emission Rate Heat Map

GHG Marginal Emission Rates Heatmap for Zone: Max (NYS)

Short Tons CO2 /MWh	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	0.47	0.47	0.47	0.46	0.47	0.49	0.49	0.49	0.51	0.50	0.54	0.54	0.56	0.56	*0.55*	*0.54*	*0.52*	*0.52*	*0.54*	*0.54*	0.54	0.54	0.50	0.49
February	0.54	0.53	0.52	0.51	0.47	0.50	0.55	0.56	0.55	0.57	0.64	0.65	0.63	0.61	*0.62*	*0.63*	*0.60*	*0.64*	*0.63*	*0.62*	0.62	0.60	0.55	0.51
March	0.46	0.45	0.45	0.44	0.43	0.44	0.48	0.49	0.50	0.50	0.51	0.51	0.50	0.50	0.49	0.48	0.48	0.49	0.49	0.51	0.52	0.49	0.47	0.44
April	0.46	0.45	0.44	0.44	0.43	0.44	0.46	0.48	0.50	0.51	0.52	0.53	0.52	0.52	0.51	0.51	0.51	0.54	0.52	0.52	0.53	0.52	0.49	0.48
May	0.45	0.46	0.45	0.43	0.43	0.44	0.46	0.45	0.48	0.46	0.51	0.54	0.53	0.52	0.52	0.52	0.51	0.50	0.50	0.50	0.51	0.51	0.48	0.45
June	0.44	0.39	0.37	0.37	0.40	0.41	0.43	0.43	0.44	0.47	0.51	0.54	0.55	0.55	0.55	0.56	0.52	0.52	0.52	0.51	0.51	0.52	0.50	0.45
July	0.50	0.48	0.43	0.42	0.44	0.43	0.42	0.44	0.45	0.47	0.50	0.55	0.57	0.59	0.59	0.58	0.59	0.60	0.59	0.55	0.54	0.52	0.53	0.53
August	0.56	0.51	0.50	0.47	0.48	0.47	0.48	0.47	0.49	0.51	0.57	0.60	0.63	0.64	0.64	0.63	0.67	0.67	0.66	0.65	0.61	0.60	0.58	0.59
September	0.49	0.48	0.44	0.43	0.45	0.45	0.49	0.50	0.52	0.52	0.54	0.56	0.56	0.56	0.57	0.60	0.61	0.61	0.58	0.58	0.57	0.56	0.54	0.51
October	0.44	0.44	0.42	0.40	0.44	0.44	0.44	0.49	0.48	0.48	0.51	0.54	0.55	0.52	0.53	0.50	0.51	0.52	0.54	0.54	0.53	0.51	0.48	0.46
November	0.39	0.39	0.38	0.36	0.37	0.41	0.44	0.47	0.49	0.48	0.54	0.53	0.52	0.50	0.53	0.52	0.50	0.55	0.56	0.53	0.52	0.50	0.44	0.40
December	0.43	0.42	0.41	0.38	0.38	0.44	0.46	0.47	0.48	0.49	0.50	0.51	0.50	0.51	0.51	0.50	0.51	0.58	0.57	0.54	0.54	0.50	0.47	0.44

Shaped Hourly E Values for Zone: Max (NYS)

$/MWh	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
January	25.39	25.23	25.74	24.73	25.24	26.58	26.69	26.35	27.56	27.12	29.16	29.01	30.21	30.62	*29.75*	*29.34*	*28.33*	*28.09*	*29.00*	*29.20*	29.34	29.16	26.89	26.81
February	29.37	28.75	28.43	27.66	25.25	27.29	29.85	30.44	29.83	30.67	34.55	35.22	34.03	33.23	*33.52*	*34.08*	*32.57*	*34.58*	*34.29*	*33.42*	33.71	32.27	29.65	27.81
March	24.88	24.45	24.57	24.10	23.45	23.79	25.85	26.39	26.94	27.29	27.65	27.38	27.03	27.05	26.63	25.93	26.27	26.63	26.41	27.50	28.06	26.68	25.44	23.88
April	24.75	24.22	23.76	23.70	23.55	23.61	25.14	26.09	26.83	27.53	28.17	28.72	27.99	27.94	27.52	27.91	27.54	29.16	28.41	28.08	28.54	28.02	26.69	25.88
May	24.50	24.98	24.44	23.40	23.28	23.91	24.82	24.58	25.99	24.75	27.67	29.30	28.56	27.98	28.06	28.07	27.85	26.90	27.08	27.25	27.57	27.51	25.76	24.58
June	23.65	21.28	20.22	19.83	21.52	22.46	23.06	23.53	23.64	25.69	27.56	29.01	29.59	30.07	29.92	30.56	28.35	28.32	28.45	27.39	27.38	28.22	27.28	24.58
July	27.22	25.79	23.14	22.66	24.09	23.48	22.60	23.61	24.39	25.69	27.32	29.58	31.15	32.08	32.19	31.55	32.11	32.45	31.71	29.94	29.35	28.34	28.76	28.57
August	30.24	27.90	27.11	25.69	25.74	25.72	25.77	25.47	26.80	27.59	30.75	32.34	34.21	34.71	34.93	34.38	36.22	36.24	35.89	35.15	33.15	32.51	31.28	31.99
September	26.53	26.17	24.06	23.11	24.17	24.64	26.30	26.94	27.92	27.95	29.33	30.48	30.46	30.37	30.63	32.31	32.90	32.88	31.56	31.34	30.89	30.36	29.13	27.78
October	23.67	23.86	22.75	21.95	23.75	23.75	23.89	26.35	26.01	25.84	27.40	29.18	29.85	28.38	28.65	26.89	27.88	28.08	29.39	29.36	28.52	27.86	26.23	25.03
November	21.21	21.09	20.57	19.55	20.18	22.03	23.96	25.31	26.31	25.98	29.05	28.57	28.26	27.26	28.69	27.97	27.35	29.71	30.37	28.98	28.32	26.89	24.01	21.56
December	23.55	22.55	22.14	20.33	20.65	23.61	24.67	25.63	26.07	26.43	27.18	27.82	27.08	27.82	27.71	26.91	27.70	31.19	30.62	29.50	29.32	27.13	25.52	23.96

Several key takeaways emerge from this analysis:

- Hourly MERs are highly variable and change year by year, but the average peak/off-peak ratios over 2015 and 2016 are fairly stable.
- MERs are higher in the summer months (June through September) from 10 am to 8 pm (on average) due to peak load conditions; and in January and February due to marginal dual fuel generators burning oil or kerosene for the purpose of reliability and/or gas constraint relief.
- While there is minimal difference between upstate and downstate MERs (on average) throughout the year, there are zonal, seasonal and daily differences. These differences can be significant, but currently aren't large enough to warrant a more granular locational and/or dynamic E Value vs. a simpler block approach (i.e., peak/off-peak).
- MERs are fairly well aligned with NYISO wholesale energy prices, meaning that peak energy prices generally align with peak carbon emissions and vice versa.
- There are a number of days where the MERs spike and more than double from average levels, although those days are the exception rather than the rule.
- The MER analysis does not capture higher-emitting units that operate for reliability or out-of-merit order purposes and may generate at the same time as the marginal economic unit (since these higher-emitting units cannot be backed down to decrease marginal emissions).
- The increase in benefits that a dynamic E value provides to both stand-alone storage and solar + storage is on the order of 5 percent or less (based on 2015-16 historical MERs and assumed efficiency/parasitic losses of 15 percent). Nonetheless, sending this signal to the marketplace is a step toward more granularity in E value and positioning energy storage systems to support a

more decarbonized grid in the future. This becomes more important in the future as more renewables join the generation fleet which is expected to increase the difference between peak and off-peak MERs, especially if renewable curtailment increases, at which point MER carbon savings can become significant.

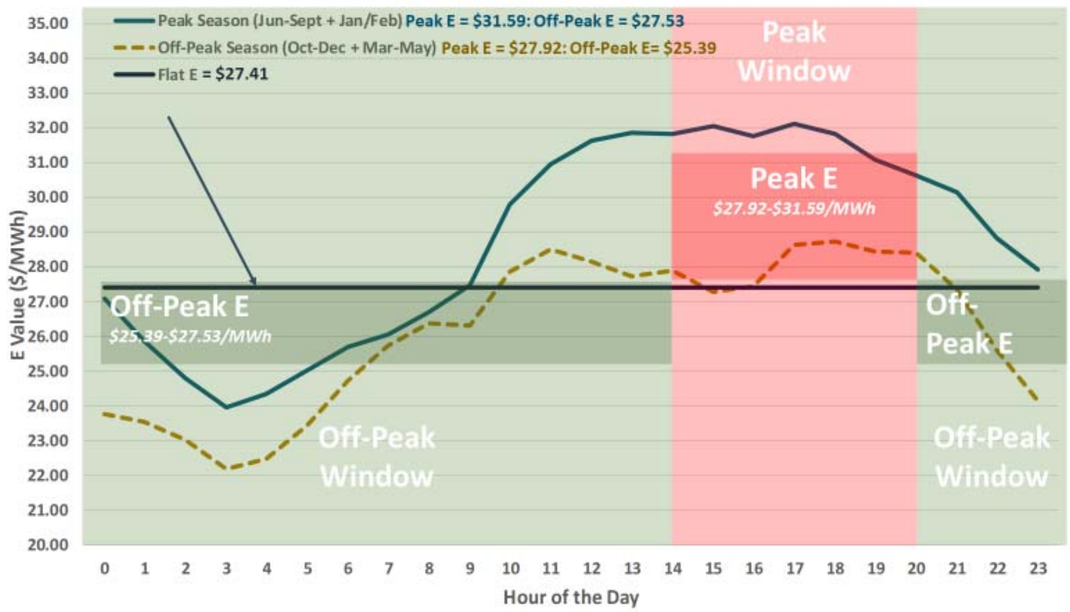
Recommendations

Shaping the E Value will better reflect marginal carbon emissions and send a more dynamic signal to DERs to reduce carbon emissions for New York's electricity system. Recommended actions are as follows:

- Create a 4-8-hour window for a statewide peak E Value that varies by season.
    - Staff initially proposes a 5-hour window from 2 pm to 7 pm to align with the Capacity Alternative 2 Option under the Value Stack.
    - Average 4-8 hour peak MERs have historically been relatively constant throughout the day, but New York's electricity system is changing; a shorter window is well positioned to capture the MER peaks over time.
    - Seasons should be defined based on observed peak emissions.
        - Peak season: June, July, August, September, January and February.
        - Off-peak season: October, November, December, March, April and May.
- MERs should be averaged on a rolling basis across multiple years to limit hourly "noise" and to provide a stable signal that also reflects dynamic system conditions. Load weighting vs. simple averaging should be explicitly examined.
- For non-energy storage technologies (i.e., solar), the shaped E Value would not be mandatory but could be considered as an opt-in under the VDER's Phase 1 Value Stack.
- For energy storage systems that charge from grid energy, the net carbon benefit should be calculated based on an assumed peak/off-peak delta, which should then become the storage E Value in the VDER Phase 1 Value Stack. This recommendation is illustrated in the figure below (based on the NYISO 2015-16 MERs).[46] Systems that can demonstrate they charge entirely from renewable energy, such as in a paired situation, should receive the full carbon benefit displaced during peak E hours.

[46] The figure visualizes a seasonal peak/off-peak E Value vs. the current flat E Value as determined using historical MERs. As can be seen in the off-peak season, the off-peak E Value is lower than the current flat E Value, while the peak value is slightly higher. In the peak season both the off-peak and peak E Values are higher than the current flat E Value.

Figure 11. Peak and Off-Peak E-Value



- An annual assessment should be made of whether a more dynamic E Value (time and location) is appropriate based on changing system conditions and MERs and given assumptions about increasing renewables penetration in certain zones and the expectation that a more dynamic E Value would add incremental benefits in such a scenario.
- The utilities should work with the NYISO to create an acceptable multi-year hourly MER dataset by zone that can be used to create a rolling MER average on a zonal and statewide basis.

Path Forward

- The VDER Value Stack working group should evaluate and consider the shaped E Value recommendations above to inform a DPS Staff whitepaper on this topic in 2018. A shaped E Value should be made available as part of the VDER Value Stack. Initially the shaped E value is expected to be similar in nature to the current flat E in terms of tenor (i.e., 25 years) and established statewide. However, the benefits of a more regional (i.e., upstate vs. downstate) or zonal shaped E should be examined along with a more dynamic shaped E that adjusts every year to inform the Staff whitepaper.
- Utilities should immediately begin incorporating a shaped E-value approach in the various BCA analyses they conduct.

4.1.5 Dynamic Load Management (DLM) Program Improvement

Background

Utility and NYISO Demand Response programs have been in place for several years in New York and are continuously modified to improve program rules and payment mechanisms in an effort to maximize participation. As shown in the Roadmap's use case analytics for behind-the-meter applications, more certainty in DLM revenue through longer-term participation can reduce financing costs and improve the economics of energy storage. These recommended actions focus on utility DLM programs, which may serve as a basis for additional load management approaches in the future.

Recommendations

- Utilities should be required to offer an option for multi-year DLM program participation agreements where terms of participation remain unchanged for 3 to 5 years or longer based on the specific utility circumstances. These agreements could be competitively procured, offered at a premium or a discount as appropriate based on best forecasting, and include penalties for non-performance so that this load relief is not subject to excessive de-rating in system contingency planning.
- Utilities should change higher priority designations (i.e., Con Edison Tier 2) within their DLM program to remain unchanged for periods of 3 to 5 years or longer based on the specific utility circumstances. An orderly transition for DLM resources participating in "Tier 2" locations should also be established in the case of a Tier 2 circuit designation being usurped by an NWA procurement. For instance, competitively selected multi-year DR agreements could transition to NWA participation.
- Utilities should also establish a "premium" auto-DLM resource category (such as was demonstrated by Con Edison's ARRA-funded Smart Grid Demonstration project) that requires high performance factors, availability, multi-year participation commitments, visibility and reliability (as with automated machine-to-machine, or M2M, dispatchability).
- Utilities should establish a manner of DLM participation for energy storage where performance can be directly sub-metered at the storage system. This is in contrast to performance being compared to a customer load baseline that may poorly reflect the storage system's impact. Additionally, on days of DLM calls, DLM performance could allow the storage system operation to change to meet the specified DR dispatch window without negatively impacting monthly kW demand.
- Utilities should consider ways to limit fossil fuel generators from being advantaged by changes that emphasize multi-year and dispatchable DLM participation. For example, current DLM programs limit generator participation to 20 percent of participating MWs. In addition, fossil generation participation must be in compliance with any final rule adopted based on the DEC's recently released Express Terms for 6 NYCRR Part 222, Distributed Generation Sources.[47]

Path Forward

- The Commission should consider DLM program changes within its energy storage order later this year with any changes implemented by utilities for the Summer 2020 capability period. This will enable the development of specific rules and allow for the necessary outreach and education to the DLM aggregator community.

4.2 Utility Roles

4.2.1 Earnings Adjustment Mechanisms

Background

The New York REV initiative has a strong focus on changing the utility business model to enable utilities to earn revenue based on outcomes that are relevant to achieving the State's clean energy and system efficiency objectives. While several Earnings Adjustment Mechanisms (EAMs) have already been established in many of the New York utilities, it is reasonable to continue their development as the costs

[47] *See* Draft Express Terms of 6 NYCRR Part 222, Distributed Generation Sources (May 16, 2018), available at: http://www.dec.ny.gov/docs/air_pdf/replacepart222.pdf.

of new technologies like energy storage continue to decline so that the utilities have incentives to consider those resources and reduce overall ratepayer costs. Load factor (the ratio of peak to off-peak energy use), in particular, is recommended by Staff as an EAM that could be effective in deploying energy storage and other DERs. Storage is uniquely qualified to improve load factor, as it increases off-peak load and decreases peak load, and can make the most significant improvement to load factor per unit of any technology. Also, since load factor is based on annual peak, storage can also contribute to meeting other EAMs (i.e., peak demand reduction).

Recommendations

- To align utility actions with the delivery of system value to ratepayers, create a new EAM for each utility that incentivizes the improvement of the distribution-system-wide load factor, calculated by percentage improvement in load factor. The incentive opportunity available should be determined based on a share of the overall ratepayer benefits to be provided by the actions.
- To mitigate what could become a reverse incentive to simply increase off-peak load to improve load factor, the EAM could mandate that a peak-reducing technology be deployed for this solution and off-peak energy usage may not increase more than a defined percent for every percentage of load factor improvement, thereby guaranteeing peak reductions and grid value.

Path Forward

- Consider in the Commission's storage Roadmap order and, if adopted, require each utility to propose a load factor EAM as described above in its next rate case filing.

4.2.2 IOU Business Model

Background

Competitive ownership of storage in DER markets is core to REV principles, and therefore, the existing limitations on utility ownership should be maintained if possible. The project economic modeling that supported development of this Roadmap, which included various ownership assumptions, did not present a compelling economic reason to reexamine the Commission's decision on utility ownership of energy storage.[48] The REV Track One Order addressed the question of utility ownership of storage by recognizing that unrestricted utility participation in DER markets presented a greater risk of undermining markets than a potential for accelerating market growth. The Commission ruled that utility ownership of DER would not be allowed unless markets have had an opportunity to provide a service and have failed to do so in a cost-effective manner and established specific exceptions to this ownership prohibition. Exceptions include: when procurement of DER has been solicited to meet a system need, and a utility has demonstrated that competitive alternatives proposed by non-utility parties are clearly inadequate or costlier than a traditional utility infrastructure alternative; when a project consists of energy storage integrated into distribution system architecture; when a project will enable low or moderate income residential customers to benefit from DER where markets are not likely to satisfy the need; or when a project is being sponsored for demonstration purposes.

While this approach remains the first best choice, recent proposals by the NYISO to subject energy storage resources in mitigated capacity zones to buyer-side mitigation measures could result in inappropriate

[48] *See* Case 14-M-0101, REV Track One Order.

barriers to entry.[49] This outcome would inappropriately mitigate resources that lack the incentive and ability to exercise market power, thereby preventing storage resources from accessing the wholesale capacity markets. If this outcome occurs, Staff recommends that the Commission reconsider whether utility ownership of storage could be a necessary option as a result of the de-facto absence of competitive capacity markets for storage resources.

Recommendations

Project economic modeling for this Roadmap, which included various ownership assumptions, did not present a compelling reason to reexamine the Commission decision on utility ownership of storage.[50] **Competitive and third-party ownership of storage in DER markets is core to REV principles**, and therefore existing limitations on utility ownership should be maintained. If storage resources become subject to buyer-side mitigation measures in the wholesale capacity markets, however, Staff recommends that the Commission reconsider these utility ownership restrictions (other than in specified exceptions), to accommodate the legitimate State policy interests outlined in the Roadmap, if storage resources are subjected to buyer-side mitigation measures in a way that will prevent their entry into the wholesale capacity markets.

4.2.3 Facilitating NWA Projects on Utility-Owned Land

Background

Unlike other DERs that can be installed on customers' premises, utility-scale storage systems may require locations with specific locational attributes and/or may incur significant interconnection investments. Conceivably, the best location and the one with the simplest interconnection may be on utility land. When land and interconnection costs are unknown, it is difficult for developers to submit accurate and complete request-for-proposals (RFP) responses. Developers have requested more certainty in the availability and cost of utilizing utility-owned land for NWAs, and more guidance from utilities on potential interconnection costs prior to bidding.

Recommendations

Identifying suitable utility land and infrastructure can reduce NWA costs and implementation time. The utility should estimate the fair-market value of the land or infrastructure and estimate interconnection costs in the issued RFP. While any property lease would still be subject to Section 70 of Public Service Law, inventorying and valuing these will accelerate the process and may enable better solutions.

- Utilities should be directed to inventory and estimate the fair-market value of unused utility land near NWA-eligible areas, considering the utility's opportunity cost of the property and future planning needs.
- Utilities should calculate the expected range of interconnection costs for non-binding planning purposes for DERs situated on utility land near any proposed NWA. Similarly, utilities should provide guidance on local situations that may have substantial impact on interconnection cost and can reasonably be anticipated. Alternatively, utilities could indicate that interconnection costs be borne by them and considered in calculating the BCA for the project, which would eliminate the need for developers to estimate these costs.

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[49] *See* NYISO Presentation: Capacity Market Rules for Energy Storage Resources (May 23, 2018), http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2018-05-23/Initial%20ESR%20Capacity%20Model.pdf.

[50] *See* Case 14-M-0101, REV Track One Order.

Path Forward

- By the end of 2018, a mechanism for the standardized valuation of unused utility land should be included in utility BCA handbooks.
- Any obstacles to leasing utility-owned land for the use of an NWA should be identified by stakeholders in comments to the Roadmap.
- NWA RFPs should include estimated interconnection costs or indicate that such costs will be borne by the utility and included as a cost in the BCA calculation.

4.2.4 Optionality in the IOU Benefit-Cost Analysis (BCA)

Background

Energy storage systems are characterized by their flexibility in terms of modularity, potential multi-use applications, and in some cases mobility. The flexibility of storage endows these resources with many options for use and deployment, even after installation. In capital planning, this flexibility is known as **optionality** and is particularly valuable given the uncertainties in forecasts and the changing needs of the electric system over time. Quantifying optionality value provided by storage requires careful analysis in utility capital budgeting and planning processes, particularly in potential NWA[51] projects and proposals.

Currently, New York's regulatory benefit-cost analysis (BCA) framework relies upon deterministic net present value (NPV) calculations that ignore optionality and forecast uncertainty. Projects that appear to be higher cost on a deterministic basis may be the lower-cost option when risk and uncertainty of future conditions are accounted for. As a result, many projects that could benefit both utilities and ratepayers may not be selected because they cannot pass existing deterministic BCA tests.

By contrast, **real option analysis**[52] incorporates uncertainty by calculating the value of optionality under a variety of circumstances and considers the additional information available after an investment has been made. Real option analysis does not replace NPV, but rather augments NPV in situations where 1) the NPV is close to zero; 2) an investment is flexible (i.e., multi-use, modular, and/or mobile); or 3) information about the future is uncertain. As a tool, real option analysis is more of a scalpel than a blunt instrument, and it may not be suitable for all circumstances and resources; therefore, it should be applied within a defined framework.

For example, suppose a distribution utility identifies a future potential constraint that would normally require a $20 million traditional infrastructure investment and whose construction would begin immediately. By deploying storage for $2 million, the utility could defer the traditional investment for five years, at which point it would be able to determine future load more accurately. For simplicity's sake, assume that there is a 50 percent chance the traditional infrastructure investment will be required after five years and a 50 percent chance it will not be required – a scenario that is captured in the following equation:

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[51] *See* REV Connect Non-Wires Alternatives DER procurement website, available at: https://nyrevconnect.com/non-wires-alternatives/.

[52] Real option theory or valuation has been used for decades in many capital-intensive industries. In the electricity industry, the traditional application of real option theory has mostly involved valuing generation assets, especially assets that are dual fuel. *See* R. Kenneth Skinner, *How to Value Energy Assets Using Real Options*, NATURAL GAS ELECTRICITY JOURNAL 26, 3 (2009) available at: http://www.integralanalytics.com/files/documents/related-documents/RealOptions%20Oct2009.pdf.

$$Optionality\ Value\ of\ Storage\ =\ Expected\ Value(Needed\ Infrastructure\ Investment) - \$2\ million = (50\% * \$20\ million) + (50\% * \$0\ million) - \$2\ million = \$8\ million$$

The net optionality value of the storage is $8 million: $10 million value minus the $2 million cost of the option to defer, where the option cost or value is presumably based on the value of that deferral.[53]

In summary, the option value of storage falls into three basic categories:

- **Timing**: closest to current practice, this refers to the value of delaying large, irreversible investment decisions by making smaller initial investments until more information about future conditions is known.
- **Staging**: the ability to commit investment in stages according to real options analysis.
- **Expand vs. Contract/Exit**: the ability to expand or contract/exit the project over time in response to changing market or project conditions.

Recommendations

A number of steps should be implemented in order to explore an approach to real option valuation for possible integration into New York utilities' capital and distribution system planning when considering storage and other DERs that could provide additional benefits to utility ratepayers, especially in NWA processes:

- Starting as soon as practicable, utilities shall supplement their BCAs with estimates of option value and present those estimates for consideration to Staff in the course of the evaluation of NWA solutions. Such estimates should take account of the basic aspects of optionality in the project in the consideration, include the value of such optionality in the most straightforward manner, and should make reasonable use of readily practicable methodology and available data. In doing so, utilities should consider the following:
    - Developing a framework for identifying which types of utility capital projects are most appropriate for optionality analysis.
    - Applying this framework to identify an inventory of capital projects where optionality may mitigate forecast uncertainty and produce ratepayer savings.
    - Encouraging NWA vendors to highlight the optionality values in their NWA proposals and other utility procurements (where applicable).
- In parallel, a technical conference with relevant stakeholders should occur in Summer 2018 with the goal of developing and considering an appropriate variant of real options valuation methodology appropriate for utility capital planning. This conference should also provide a forum for DPS, utilities and developers to review the components of a BCA and determine whether sufficient information is included in developer proposals to allow the BCA to sufficiently consider these attributes.

[53] An example of utility T&D infrastructure investment optionality saving costs is Con Edison's Brooklyn-Queens Demand Response Management Program (BQDM), in which Con Edison's $200 million NWA investment has deferred a traditional substation investment of $1-1.2 billion for at least seven years. Subsequent load forecasts have decreased significantly as predicted electricity demand has not materialized, and it is likely that the substation is no longer needed during the term of Con Edison's current 10-year capital expenditure plan. *See* BQDM Program Overview, available at: https://www.coned.com/en/business-partners/business-opportunities/brooklyn-queens-demand-management-demand-response-program.

Path Forward

- Utilities should immediately begin to present more scenario-based BCAs. This should include considering different load growth assumptions or more broadly defining use cases for specific projects/resources over time. In addition, consideration of salvage/resale value or terminal value of assets with remaining useful economic life should be examined. This should include consideration of how the mechanics would work as a commercial matter, how a terminal value could be realized (e.g., does the developer sell to the utility at a pre-agreed price, etc.), and how ratepayers would capture such values. Collectively, these would serve as a first step towards standardizing the analysis of optionality.
- Utilities should begin development of a standardized framework for identifying when and where optionality should be considered in the context of utility capital investment or NWA procurements – for example, under conditions of high uncertainty (where there is a high value associated with waiting for more information) or for certain technologies like energy storage that have clear multi-use, modular and/or mobile applications. The goal is to ensure that forecast uncertainty is evaluated and included in capital planning and NWA development.
- Utilities should engage with relevant stakeholders to begin development of a methodology to include in BCA handbooks that details how optionality valuation should be performed and provide examples, ideally using past NWAs.
- Utilities should examine potential NWA contracting mechanisms (i.e., options) that capture the value of flexibility while ensuring the necessary revenue/cash flow for third party financing. Further, mechanisms for utilities and vendors sharing an interest in value created beyond the NWA term (i.e., potential bulk market revenues) should be pursued and could be structured as a terminal value or option for utility purchase at the end of the NWA term.

4.3 Direct Procurement

4.3.1 IOU Procurement Through NWAs

Background

Utility NWAs have increased in scope and scale and proven to be a successful mechanism to competitively procure DER solutions that can meet electric system needs more cost effectively than a traditional solution. This outcome is often enabled by the stacking of benefits that the DER provides beyond the deferral value of the avoided utility T&D. Those values include environmental benefits, generation ICAP (installed capacity) savings achieved through load relief, energy savings and ancillary services.

Recommendations

Staff considers the NWA approach to be a critical point from which to expand on the utility's ability to lower the total electric cost to their customers. To further expand the potential benefits that DERs, including storage, can provide to ratepayers, utilities should expand the scope of NWA opportunities (referred to as "NWA+") to include the consideration of expanded DER portfolios that will reduce their customers' total bills.

Specifically, for each NWA identified, Staff recommends the utility be required to examine the potential to procure additional MW of storage that would be operated specifically to decrease the system peak load (and ICAP tag) of the utility's full-service customers or the NYISO zone, thereby cost-effectively reducing customers' total bills. Utility RFPs for NWAs should also specifically cite the intent for third party developers to sell into NYISO markets when the storage asset is not needed for distribution system and system peak relief. Such an approach will help to maximize ratepayer benefits.

Additionally, when examining the location of an NWA, the utility should identify whether an existing peaking power plant or unit resides in that location interconnected at the appropriate voltage level to allow the NWA solution to also meet peaker needs including local reliability for contingency purposes. Doing so may offer the opportunity to leverage the existing footprint of the peaker plant or unit and interconnection point more cost-effectively.

This expanded NWA approach is a path toward establishing value sharing between ratepayers, developers and utilities in the future. Staff also recommends that NYSERDA work with the IOUs to determine how a market acceleration bridging mechanism can be integrated into NWAs to enable these expanded NWA services to be deployed more quickly, so that a minimum of 100 MW of energy storage is deployed to meet expanded NWA services. Staff recommends that a fixed capacity payment be considered in this approach for the term of the NWA, with a fixed value for the capacity based on a discount of forecasted zonal capacity prices so that ratepayers receive a benefit from what otherwise is expected to be the cost for that capacity. In this manner, developers would receive bankable contracted revenues in return for performance, and ratepayers will receive any upside potential should capacity prices rise higher than forecasted.

Path Forward

- Consider in the Commission's storage Roadmap order and, if adopted, require utilities to update their NWA eligibility criteria guidelines to account for the expanded scope of NWAs. This topic should be included in the technical conference addressing optionality, and the Commission should consider this information in its energy storage Roadmap order.

4.3.2 NWA Term Extension

Background

Energy storage systems typically have an expected lifetime of at least 10 years, and other components of the storage NWA proposal may have even longer expected lifetimes. This can often exceed the term of some NWAs, introducing significant revenue uncertainty after the NWA period has ended and making it difficult for any form of capital solution to be deployed by a third party to meet the NWA need. Decreasing this risk by including term extension provisions will encourage storage developers and other DER providers to participate in RFPs, which in turn increases competition and ultimately lowers the costs of NWAs for ratepayers. Furthermore, with changing system needs over time, an extension of the NWA term may become beneficial to ratepayers in the future.

Recommendations

- NWA contracts should include clearly-defined conditions for the extension of an NWA's term when a proposed NWA DER asset has a life expectancy greater than the original NWA term. The RFP should either include specific conditions or request respondents to provide terms by which this would be handled.
- Developers should be explicitly allowed to maintain the interconnection after the term of an NWA that ceases to provide distribution services and should be allowed to continue to use that asset to participate in NYISO markets.

Path Forward

- The utility BCA handbook should be updated to account for the potential of project extensions. This topic should be included in the technical conference addressing optionality.

4.3.3 Large Scale Renewables Procurement

Background

New York's Large Scale Renewable (LSR) programs, led by NYSERDA and NYPA, encourage energy storage development in conjunction with intermittent renewable generation. The aim is to promote the addition of flexible storage assets in the bulk system as New York State increases the amount of intermittent resources. The flexibility of storage is expected to both increase renewable energy generation (increasing RECs) and provide operational flexibility to make generators and the grid run more efficiently. For example, NYSERDA's LSR evaluation criteria give additional consideration (currently up to six additional points) to bids committing to develop energy storage in addition to the REC-generating renewable facility. Developers can either co-locate[54] the storage with the renewable generator or elsewhere on the grid where it is most valuable. Bids are submitted as a single paired package, both with and without energy storage.

Recommendations

- The manner in which storage is bid and participates under the LSR program is an area that the NYSERDA LSR team should continue to investigate based on RFP results. Key differences include the scale, development timelines, different types of sites for appropriate interconnection and multiple market participation models.
- Co-locating storage with a renewable generator is not currently practical or rewarding due to NYISO market rules. If a developer found it most economical to develop a renewable generator with co-located storage to improve dispatchability, it would lose its favorable NYISO treatment as an Intermittent Generator, which is an area flagged for wholesale market recommendations (Section 4.7).

Path Forward

- Continue to refine the LSR procurements to reflect operational flexibility that improves system benefits.
- Examine wholesale market changes that could provide the best signals for pairing intermittent renewables with energy storage.
- As described in the "Clean Peak" approaches below, continue to examine the manner in which energy storage either co-located with renewables or separately installed could increase renewable utilization, reduce curtailment, and reduce ramping impacts in the future as larger levels of renewables are deployed.

[54] In order to qualify for the Federal investment tax credit (ITC) energy storage needs to be directly charged by the output from the renewable generator (i.e. wind/solar), which practically requires co-location. There may be additional reasons in the future to encourage Large Scale Renewables to include storage to better align generation with system need. This might be needed, for example, to better align production with demand to avoid curtailment, if storage improved deliverability as a non-transmission solution, or if more ramping-capable resources were needed.

4.3.4 NYS Leading by Example

Background

- New York State and municipal government buildings and affiliated entities consume large quantities of the total electric used in the State. In NYC, city buildings including City University of New York (CUNY) campuses consume 8 percent of the total electricity used. Executive Order 166 calls upon State agencies to demonstrate their contributions to the State's greenhouse gas reduction goals of 40 percent by 2030 and 80 percent by 2050. Building on this, in May 2018 Governor Cuomo challenged State agencies to further Lead by Example in energy efficiency, calling for all agencies to develop energy sustainability master plans; to benchmark and publicly disclose their building level energy performance; and to advance zero energy new construction for low-rise office buildings in 2020, dorms/housing/public assembly by 2025, all other building types by 2030.
- The State University of New York (SUNY) campuses have also been a leader among State entities in establishing goals for renewable energy and sustainability requiring each of its 64 campuses to have resiliency by 2025, and all new construction designed to net zero energy standards by 2020, with gut rehab projects to follow shortly thereafter. This is one piece of SUNY's ambitious sustainability plan, with the goal of sourcing all their power needs from renewables and advancing clean energy innovation.
- NYPA, the largest State owned electric utility in the USA, is charged with generating and transmitting clean, low-cost power and energy services to commercial and industrial, municipal and governmental customers (amongst others) across New York.
- NYPA's role in the State energy system provides a unique opportunity to Lead by Example in storage – supporting its customers, in becoming leaders in energy storage, acting as a catalyst for longer term private sector investment and helping New York State build necessary flexibility into the grid to optimize the integration of intermittent renewables and deliver the States 40 percent GHG reduction goals by 2030.
- Finally, the Metropolitan Transportation Authority (MTA), which is one of the largest users of electricity in NYC, has established corporate-wide sustainability goals.

Recommendations

Staff acknowledges that this work is already underway and recommends that NYS continue its leadership as an early adopter of sustainable energy solutions by requiring that Office of General Services (OGS), State Education Department, Department of Corrections, and SUNY modify by the end of 2018 any existing RFPs for energy efficiency and renewable energy to explicitly include energy storage as a standalone or paired solution to meet their efficiency, sustainability and resiliency goals. Any new RFPs should also include this explicit requirement.

In addition, NYPA is already working with a variety of customers to pursue energy storage projects and Staff recommends NYPA continue in its role as a leader in early adopter of sustainable energy solutions, including energy storage and should work with key State partners to ensure that this opportunity is maximized. Specifically, NYPA should work with customers, including State and municipal facilities across New York, as well as its own utility asset sites, to accelerate the adoption of energy storage.

Path Forward

- Staff sees a large opportunity for NYS agencies and affiliated entities to serve as early adopters of DER solutions including energy storage. Staff recommends that NYSERDA work with key State partners to ensure that this opportunity is maximized. Specifically, NYSERDA should work with Office of General Services and SUNY to ensure that opportunities to deploy energy storage and paired on-site generation solutions are included in energy efficiency, renewable energy and resiliency procurements.

- NYPA, which is responsible for the K-Solar program, working to install solar systems on schools throughout New York,[55] and NYSERDA should work with the State Education Department to maximize deployment of solar + storage at k-12 schools throughout New York State, and to address any procurement limitations that could limit the ability of a developer to propose a paired solution that includes energy efficiency, renewable energy and energy storage.
- NYSERDA and other State partners should engage with the MTA to pursue opportunities that maximize use of the energy from regenerative braking that would otherwise be wasted and to reduce the peak impact of electrified rail on the distribution systems.
- NYPA will also pursue the following actions:
    - <u>Storage Project Design and Deployment</u>: Partner with customers, private developers and other third parties to procure and install innovative flexibility projects at NYPA assets and customer sites - demonstrating and scaling new storage technologies and flexibility business models. These projects will serve the dual purpose of providing energy services and helping to mature/accelerate market signals required to encourage longer term, sustainable private investment in storage and other flexibility tools
    - <u>Procurement:</u> NYPA will work with customers to ensure that opportunities to deploy energy storage and paired on-site generation solutions are included in energy efficiency, renewable energy and resiliency procurements
    - <u>Public/Private Partnerships:</u> enable more opportunities for public facilities to partner with private sector developers to reduce risk and increase funding
    - <u>Demonstrate the Value of Data:</u> capture, asses and share real-world project data to evaluate customer load and operational data to identify highest value opportunities to deploy storage, support and prove value analysis, inform regulatory agencies, and build confidence among market participants (e.g., customers, investors). For example, NYPA will work with the other utilities, customers and other third parties, utilizing its NYEM and EDGE platforms to capture customer building energy usage and identify candidates for reducing energy demand using energy storage standalone or paired with other solutions – including the benefits of added resiliency.

4.4 Market Acceleration Incentive

Background

Installed energy storage costs have declined by an average of 10-15 percent per year since 2010 and these cost declines are forecast to continue into the mid-2020s. While largely driven by cost declines in lithium ion battery hardware, all storage technologies have experienced decreased costs. The recommendations contained in this Roadmap increase the economic viability of energy storage in all use cases presented. However, in order to accelerate soft cost declines, and increase the market learning mechanisms for customers and for system operators by deploying and utilizing these assets today, Staff recommends a bridge incentive be considered to improve project bankability to enable a self-sustaining market.

[55] *See* NY Power Authority K-Solar FAQ, accessed at: https://nypa.gov/innovation/programs/k-solar/k-solar-faq.

Soft cost reductions and local market learning can result in "bending" the energy storage installed cost curve down as compared to what it otherwise would have been if the actions recommended in this Roadmap are not adopted, and New York instead relies on un-accelerated market evolution without intervention. In the case of storage plus PV projects, this cost reduction can also occur by leveraging the federal Investment Tax Credit and in cost savings associated with combining the permitting and interconnection costs of the systems. A bridging mechanism to a scalable and self-sustaining market can result in significant beneficial impacts and cost savings to the New York State market for energy storage over the longer-term and in the context of the broader transformation of the electric sector. This is especially the case with respect to deploying 1,500 MW of storage by 2025.

Recommendations

Staff recommends that NYSERDA work with the IOUs and LIPA/PSEG to develop an Energy Storage Market Acceleration bridge incentive, via multiple programs, using funds already approved by the Commission. This would begin with a NYSERDA-initiated storage adder within NY Sun for paired PV plus storage, and will be followed by a program for standalone storage systems and/or an incentive to be delivered via utility NWAs, to be determined by the Commission. These bridge incentives should prioritize projects where established line of sight cost declines enables the project to be deployed based on cost and market opportunities alone within the next three to five years.

Staff also recommends that NYSERDA, the distribution utilities, and LIPA engage with stakeholders during the formal public comment period to establish the framework for how a bridge incentive would be deployed to ensure coordination among entities and provide clear and consistent market signals. Stakeholders have also expressed a number of potential system values that are not monetizable today. These include hosting capacity improvements, avoided emissions beyond carbon, reduced renewable curtailment and system resilience among others. Staff acknowledges the complexity in valuing many of these other factors, many of which are highly location-dependent, and seeks input into valuation approaches in the context of program design for the bridge incentive.

Staff recommends establishing an approximately $350 million bridge incentive statewide including in LIPA/PSEG to accelerate adoption of customer-sited storage and storage sited on the distribution or bulk systems, including when paired with clean generation sources. To leverage the current NY Sun program, by fall 2018, NYSERDA shall create an adder for storage systems under NY Sun to spur new PV plus storage projects. An additional program for standalone systems would be separately deliberated and developed through the Commission proceeding in Case 18-E-0130. Incentives should be designed at levels aligned with declining storage costs to accelerate these cost declines, foster innovation and enable a self-sustaining market without incentives. Staff recommends that existing sources of funds such as funds authorized under the Clean Energy Fund or other previously collected but currently uncommitted funds be identified to support this recommended funding commitment.

Staff estimates that such an incentive program could support a significant amount of customer-sited and distribution/bulk sited storage by 2021–22 while accelerating cost declines, deploying over one-third of the 1,500 MW 2025 target, and establishing critical foundations for a self-sustaining market without direct incentives. Staff estimates that a bridge incentive program could reduce soft costs by up to $50 per kWh for a distribution/bulk-sited system and up to $150 per kWh for a customer-sited system by 2025 compared to 2017-18 costs and improve project bankability to enable a self-sustaining market. Moreover, this program is projected to accelerate the cost decline curve by almost two years and save approximately $200 million from the projected cost of deploying 1,500 MW of energy storage by 2025 and more than $400 million from the projected cost of deploying 3,000 MW by 2030.

Staff is interested in stakeholder input into the bridge incentive structures, payment mechanisms, and implementation approaches. Staff is also continuing to seek feedback on appropriate mechanisms that could be put into place to value the renewable and environmental attributes that energy storage could provide to the bulk wholesale system. The following principles are provided as a foundation by which this market acceleration mechanism could be established:

- Prioritize those use cases with the best economics and ability to scale quickly within the next 3-5 years.
- While representative modeled project economics have been presented for specific customer use cases, in no way are these intended to be limiting in the development of a bridge incentive. Staff is particularly interested in stakeholder feedback on the near-term deployment potential across all market segments and respective opportunities to leverage and attract private capital. For customer-sited storage (for demand metered customers and mass-market customers), Staff seeks feedback including the number of customers that could likely adopt storage, MW and MWh that could be deployed, and specific geographic locations.
- As described in the NWA recommendations, Staff recommends that utilities accelerate market learning experience and lay the foundation for third party shared savings models by procuring NWA solutions that can provide greater overall ratepayer benefits (e.g., T&D deferral, capacity savings, ancillary services). Improvements to the BCA may better recognize some of the system values that storage may provide, including optionality. In the near term, as market learning increases and as dual market participation rules are developed, Staff recommends that NYSERDA provide a declining bridge incentive through the utility NWA procurements to enable these expanded NWAs to be deployed more quickly. Such a bridge incentive could include a ceiling price per kW/kWh and be based upon location and additional grid services beyond utility T&D deferral. Staff also recommends that a fixed capacity payment be considered for the term of the NWA with the capacity value based on a discount of forecasted zonal capacity prices to provide savings to ratepayers. In this manner, developers will receive bankable contracted revenues in return for performance, and ratepayers will receive any upside potential should capacity prices rise higher than forecasted.
- Staff seeks stakeholder input into the modeled project economics presented in this Roadmap, the assumptions utilized, and the timeframe within which the installed costs are expected to be achieved. This includes deployment projections and the amount of bridge incentive required to deploy at least 500 MW by 2021-22.
- Standalone storage and storage paired with intermittent renewables, on-site power, and energy efficiency should all be permitted. NYSERDA should develop any investment plans incorporating flexibility to reallocate funding within use cases (e.g., standalone vs. storage paired with generation) to ensure that the maximum amount of energy storage is deployed as market conditions and deployment factors change over the near- to medium-term. Recognizing the pending step down of the federal Investment Tax Credit, Staff recommends that NYSERDA move forward with submitting an investment plan chapter to DPS for a solar + storage bridge incentive that can begin funding these paired projects from already-approved Clean Energy Investment Funds.
- Staff recommends that DPS and NYSERDA Staff work with LIPA/PSEG to develop an equivalent set of market acceleration bridge incentive mechanisms on Long Island.
- Finally, Staff recommends expanding the existing NYSERDA value stacking solicitation (PON 3541), which can fund use cases that are not monetizable or possible today, in order to expand bulk system projects that could be monetizable in the future under the NYISO's DER Roadmap.

Path Forward

- Staff and NYSERDA engage with stakeholders, the utilities, LIPA/PSEG, NYPA and other parties within the comment period to consider program design and incentive levels; Staff recommends that the Commission require an investment plan be submitted by NYSERDA within 60 days of Commission order and that implementation begin within 90 days of Commission order.
- LIPA/PSEG should develop comparable bridging incentive mechanisms for Long Island and follow the same schedule dictated by the Commission's energy storage order.
- NYSERDA should examine changes to the NYSERDA value stacking solicitation and make any modifications before the end of 2018, including any investment plan chapter amendments.

4.5 Address Soft Costs Including Barriers in Data and Finance

4.5.1 Continue to Reduce Soft Costs

Background

Energy storage installed costs continue to decline by an average of 10 to 15 percent annually, with these declines predominantly being driven by hardware cost declines arising from manufacturing scale up. While multiple forms of storage technology will ultimately address system needs, most market research firms indicate that lithium-ion will comprise a majority of electrochemical storage systems deployed in the near term as electric vehicle evolution and adoption continue to drive price reductions. Thermal storage will also continue to play a prominent role.

Regardless of technology, however, soft costs associated with customer acquisition, siting and permitting, and interconnection are driven by local factors and will not decline in parallel with hardware costs without New York State action. These soft costs can comprise up to 20 percent of the total installed cost of an energy storage system. Engineering, design, construction, and financing costs also contribute to energy storage non-hardware costs, which can be reduced by State action. Without a concerted effort to meaningfully reduce these non-hardware costs, their proportion of total project costs will actually *increase* as hardware costs decline.

In 2016, NYSERDA embarked on a four-year effort to reduce soft costs by at least 25 percent by 2019 and 33 percent by 2021, compared to a 2016 baseline for electrochemical systems. This baseline was approximately $200+/kWh, which was based on primarily lead acid projects installed behind-the-meter in Zone J with an average total installed cost of approximately $1,000/kWh and an average soft cost of approximately 20 percent. Funded by $8.1 million under the Clean Energy Fund, this work focuses on permitting, customer acquisition, technical consulting (on projects in development), and measurement and verification (of deployed storage projects) in order to increase potential customer and financier confidence.

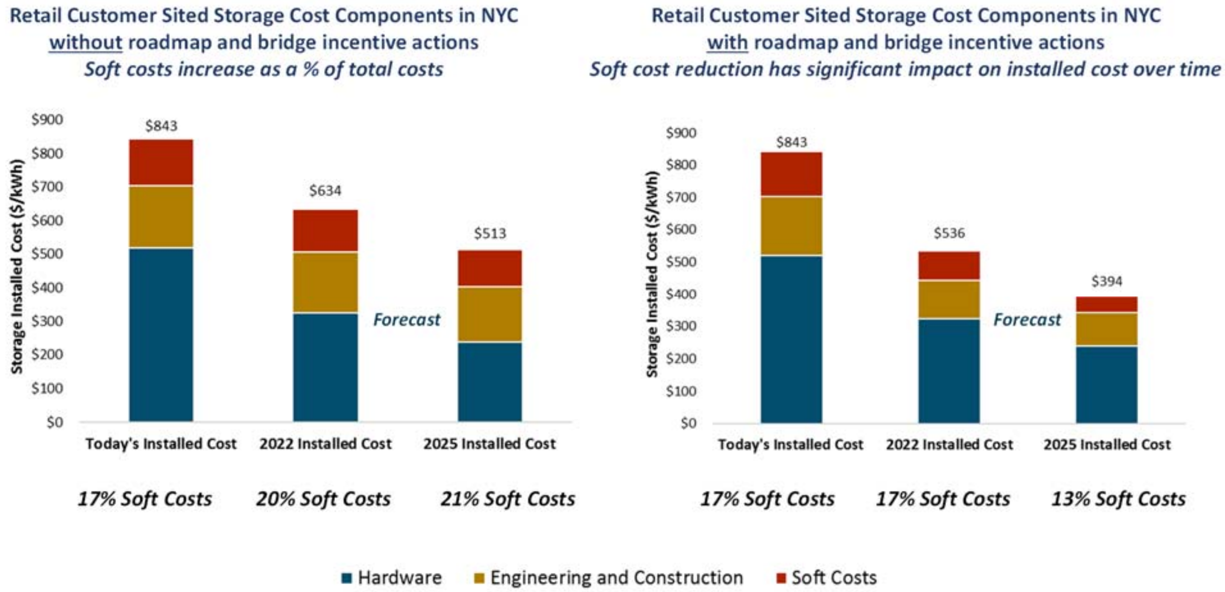
Data from 2017 installed or contracted storage systems in New York, predominantly electrochemical systems, has indicated an average total installed cost of approximately $840/kWh in Con Edison's territory and an average soft cost of approximately 17 percent or $140/kWh. Total average costs from 2017 were approximately: hardware (batteries and balance of system costs), 62 percent; engineering and construction, 22 percent; and soft costs, 17 percent. These soft costs comprised 8 percent for permitting, 3-4 percent for customer acquisition, and 5 percent for interconnection.

Data from 2017 for front-of-the-meter electrochemical projects in early stages of development has also begun to emerge. These projects constituted a very limited sample size, were outside of Con Edison's territory or Long Island, were lithium-ion chemistries, and indicated approximately 70 percent for hardware costs and 30 percent for all non-hardware costs.

Opportunities are available for NYS interventions to drive down soft costs by up to $50 per kWh for a distribution/bulk sited system and up to $150 per kWh for a customer sited system by 2025 compared to 2017-18 costs and improve project bankability to enable a self-sustaining market. While NYS is a hub for technological innovation, hardware cost declines will generally be more impacted by global trends. With the industry at scale, costs related to permitting, customer acquisition, and interconnection could be reduced 50 to 75 percent below 2017-18 levels by 2025. In addition, over this timeframe, hardware costs may decline 50 percent or more, and engineering and construction costs may decline by 40 percent or more as installations become more easily replicable.

The figure below illustrates the benefits of reducing soft costs.

Figure 12. Benefits of Reducing Soft Costs



Energy Storage Permitting: NYSERDA is working with contractors from the CUNY Distributed Generation Hub (which have experience with PV permitting), DNV GL (independent lab testing and subject matter experts), and Meister Consultants/Cadmus (which have experience working with permitting agencies on PV) to assist permitting agencies across New York State by disseminating model operating procedures and permitting guides while codes and standards continue to evolve. An initial focus has been to provide significant technical assistance to help Fire Department of New York (FDNY) and NYC Department of Buildings (DOB) develop clearer permitting requirements for advanced battery system installations in NYC, and to leverage relevant portions of this guidance for Authorities Having Jurisdictions (AHJs) throughout the State.

Recently, the Energy Storage Permitting and Interconnection Process Guide for New York City ("the Guide") was released to provide building owners and project developers with an understanding of the permitting, interconnection and approval processes for outdoor li-ion energy storage systems. This Guide represents the culmination of over a year of facilitated discussions with FDNY and NYC Department of Buildings and reflects requirements that the agencies have agreed they will use to review projects. Li-ion systems comprise 90 percent of the new project pipeline in NYC. These guidelines were developed to cover exterior systems first so that projects could be permitted and installed, while simultaneously working to develop this level of clarity for interior installations that are not yet considered in NYC. Interior guideline development has begun with a completion target of the end of 2018. Over the next few months, building owners and project developers will work with the FDNY and DOB to test the processes outlined in the Guide so they can be refined by the NYC, if needed, as NYC promulgates regulations based on these guidelines later this year. These guidelines are meaningful progress and serve as an example of the path that this work can take.

In addition to expanding this technical assistance to permitting agencies across the State during 2018, Staff recommends that NYSERDA engage local communities, such as on Long Island, that are likely to see large amounts of storage deployments (based on project economics and system needs) to help the communities' leadership and residents understand what storage is, its contributions to energy and environmental goals, and constraints or concerns that should be examined in reviewing projects. Additionally, NYSERDA should add energy storage to the PV Payment In Lieu of Taxes (PILOT) calculator[56] so that local communities can begin preparing for the financial impact these systems could contribute to their tax base without overestimating fiscal benefits.

Customer Acquisition: Critical to siting energy storage at customer sites is access to sub-hourly interval meter data to target customers whose load profile (peak to baseload) could benefit from energy storage. Electrochemical and mechanical solutions tend to favor peakier customers, while thermal storage favors those with large compressor loads or large hot water needs (pre-heating water tanks). In New York State today, only around 6,000 of the largest demand-metered customers have interval data available. While advanced metering is steadily being deployed, it will take five to ten years before all of the State's non-residential customers have interval data available.

Therefore, NYSERDA has engaged Energy & Resource Solutions (ERS) to conduct analytics on load data to determine characteristics that identify best-fit customers for energy storage solutions, and to consult these customers on storage opportunities. This includes market segmentation, analyzing interval meter data, conducting data logging where necessary, iterating key characteristics and algorithms, and developing tools to quickly down select customer types most likely to benefit from an energy storage system. Outreach, education, and one-on-one technical assistance for these customer classes is in progress under NYSERDA's current soft cost reduction efforts. As further described in the data section of this Roadmap, Staff recommends that the investor owned utilities, LIPA, and NYPA work collaboratively with DPS and NYSERDA to provide anonymized customer load data to facilitate targeting of best fit customer profiles for energy storage or other distributed energy solutions to reduce peak load impact on the local electric system in a manner consistent with the data requirements outlined in the Distributed System Implementation Plan (DSIP) Guidance.[57]

Industry Assistance: As retail and wholesale rate design continues to evolve, it is imperative that developers have the most streamlined access to understanding implications on their business models and product offerings so that project economics can be maximized. The New York Battery and Energy Storage Technology Consortium (NY-BEST) has been engaged by NYSERDA to develop and provide educational content and outreach to vendors on storage use cases, tariffs and regulations. This includes maximizing customer economics through standby rates, facilitating participation in demand response programs, participating in wholesale markets as opportunities evolve, and reducing interconnection costs. It is important to accelerate this leveraging of best practices and translation of complex tariffs and regulatory decisions into practical impacts. In particular, Staff recommends that NYSERDA target developers already working in New York State as well as those not yet operating in New York to make them aware of opportunities and business cases for storage. This will expand customer choice by increasing the number of developers working in New York and add additional competition to pricing.

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[56] The PILOT calculator is a tool to assist New York State municipalities considering PILOT agreements for solar energy projects larger than 1 MW. *See* the PILOT Calculator, available at: https://www.nyserda.ny.gov/-/media/Files/Programs/NYSun/PILOT-Calculator.xlsm.

[57] Case 16-M-0411, In the Matter of Distributed System Implementation Plans, DPS Whitepaper Guidance for 2018 DSIP Updates (filed May 29, 2018).

Interconnection: The NYS Standardized Interconnection Requirements[58] were recently amended to include standalone storage, raise the maximum threshold to 5 MW, and apply this threshold for paired solar + storage based on the amount of power that the combined system is intended to export (in other words, not sum the PV and storage nameplate power ratings unless the system will operate in that way). In order to prevent the potential interconnection bottlenecks that could likely occur in the future as storage reaches scale, Staff recommends that the DPS Interconnection Policy and Technical Working Groups (IPWG and ITWG) be required to incorporate standalone and paired energy storage/renewable/on-site generation into their scope. In particular, Staff recommends these working groups develop a prioritized list of critical issues that must be resolved within the next three years to allow energy storage (standalone or paired) to reach commercial scale. This priority list and the timeline by which resolution will be recommended to DPS Staff shall be developed by December 2018.

End-of-life considerations: Certain storage technologies may require various types of end-of-life actions which could involve repurposing the equipment, recycling the materials, and/or remediation/reclamation. Staff recommends that NYSERDA and the other relevant stakeholders continue to establish these end-of-life actions and processes.

Path Forward

Specifically, Staff recommends that the following areas be pursued:

- NYSERDA should submit an updated Investment Plan within 60 days of the Commission's order that includes the accelerated soft cost declines and the bridge incentive presented above.
- By December 2018, NYSERDA in coordination with the ITWG and IPWG, shall develop a schedule for soliciting bids to research and examine through field demonstrations inverter-based solutions that can adequately limit reverse power flow to avoid the need for additional relays for systems below an established threshold (e.g., 1 MW). Results shall be available so that a recommendation may be considered before the end of 2019.
- Hosting capacity should be examined from a perspective that considers the dispatchability and control that storage can provide to an otherwise-intermittent resource. The Joint Utilities (JU)[59], through the ITWG and IPWG, shall work collaboratively with stakeholders to identify possible alternative approaches for increasing hosting capacity.
- While two interconnection applications – one for storage and one for on-site power – may not yet prove a hindrance, these types of operational inefficiencies should be avoided. Staff acknowledges the strong desire for integrated capital planning and this should be reflected throughout the manner in which DERs are considered.

4.5.2 Reducing the Cost of Capital

Background

Energy storage systems today are largely financed through one of three mechanisms: customer financing, third party capital, or utility financing, with the majority being third-party financed (and largely higher-cost) equity financing. This approach involves a combination of debt financing (which carries a lower

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[58] Case 18-E-0018, In the Matter of Proposed Amendments to the Standardized Interconnection Requirements for Small Distributed Generators, Order Modifying Standardized Interconnection Requirements (issued April 19, 2018).

[59] The Joint Utilities of New York include: Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

capital cost) and equity financing (which requires a higher rate of return). The greater the tenor, amount and predictability of the earnings streams, the lower the cost of capital. Unlike energy efficiency and solar installations, however, energy storage systems can often accrue revenue and savings from multiple sources or mechanisms. This can add complexity to the project underwriting and increase transaction costs. Traditional power generators are able to finance greater portions of project cost because such deals are of large size, which may be syndicated out to investors and subsequently traded in secondary markets, and the market risk associated with wholesale electric and ancillary service prices is well established and considered in project finance modeling. This is not yet the case for energy storage, which lacks scale, precedent, operating history and standardization. The resulting lack of confidence and familiarity among financial entities increases the complexity of the transaction and can increase expenses and the overall cost of capital, especially when multiple counterparties are involved in a deal.

Staff recommendations aim to reduce uncertainty associated with energy storage revenue or savings streams, while striking a balance in order to minimize ratepayer exposure to unacceptable and imprudent risk. This includes improvements to the bankability of the VDER value stack for exports of renewable energy or energy storage, changes to retail delivery charges, load relief contracts, non-wires alternative procurements, and wholesale market changes that should be considered by the NYISO.

Recommendations

Underpinning these actions are three primary recommendations to reduce the cost of capital as deployments and the market reach scale:

- Leverage NY Green Bank's (NYGB) role as a financial institution. NYGB's purpose is to proactively find creative financing solutions to the economically viable, but less well understood business models to help drive standardization, achieve greater developer scale, and generate market activity. In his 2018 State of the State, Governor Cuomo directed the NYGB to invest at least $200 million in energy storage financing. NYGB has the capabilities to address each of these energy storage segments (customer, distribution, wholesale). The team at NYGB has experience evaluating various revenue sources and with multiple counterparties. In turn, NYGB's participation can help demonstrate energy storage project finance viability for other financial parties – especially when retail and wholesale benefits are being provided. NYGB financial products include, but are not limited to, warehousing and aggregation credit facilities, term loans and investments, credit enhancements, and construction finance, among other financial products that can be applied towards energy storage investment opportunities. NY Green Bank has issued a Request for Information (RFI) in conjunction with NYSERDA to further engage and increase active dialogue with energy storage developers and other market participants regarding specific ways in which NYGB can be helpful in financing energy storage projects in NYS. Respondents will be invited to participate in conversations with NYGB in the form of one-on-on meetings or broader stakeholder discussions to examine market barriers. The NYGB also plans to issue an RFP to support solar plus storage deployments in conjunction with NYSERDA implementing the Roadmap's immediate recommendation for a PV + storage bridge incentive. To review the RFI and offer responses, visit NYGB's "Open Solicitations" page.[60]
- NYPA is in the unique position to design, manage, own, and/or provide project finance for energy storage projects deployed at customer sites paired with NYPA generation assets and in the bulk power system. This ability to manage and finance all aspects of a project should also result in lower costs, especially as it relates to customer acquisition through NYPA's ability to bundle needs

[60] *See* NY Green Bank, Open Solicitations, available at: https://greenbank.ny.gov/Work-with-Us/Open-Solicitations.

into a single Request for Proposals. NYPA can also enter energy services contracts that bundle the cost of the storage asset into the delivery component of a customer's bill or through a shared savings model. As further explained in the Lead by Example section, Staff recommends that NYPA work with customers to prioritize competitive procurements that it can issue on behalf of its customers to cost effectively procure energy storage or paired renewable/storage/efficiency projects that meet its customers' energy and resiliency needs while also meeting the State's renewable energy and carbon reduction goals.

- Leverage the federal Investment Tax Credit (ITC): The ITC can help to lower project costs for paired solar + storage by enabling a 30 percent tax credit on the storage cost until 2019 before beginning a step-down until reaching 10 percent for commercial installations in 2021 (residential ITC is eliminated). Combined solar and storage can avoid additional transactions costs by leveraging the tax equity finance in place for solar.
- Commercial Property Assessed Clean Energy (PACE) financing is a significant opportunity that should be pursued. Recent statutory and program changes now make PACE financing much more attractive and customer-sited storage is now eligible for this on-property tax bill financing. The Energy Improvement Corporation's "Energize NY" services allow it to execute PACE financing statewide in any municipality that has passed legislation authorizing PACE. This includes all of Long Island and most of upstate New York. New York City is also planning to introduce commercial PACE financing legislation shortly which would be administered by the NYC Energy Efficiency Corporation; this could provide off-balance sheet financing for energy storage and other energy efficiency building improvements in a manner that still maintains tax advantages. In project modeling conducted in this Roadmap, PACE financing was considered an attractive alternative that could reduce the cost of capital by increasing the portion of debt financing available for a storage project (up to 100 percent debt), based on customer creditworthiness, and result in a cost of capital that could reach 6-7 percent or less.
- Finally, Staff recommends that NYSERDA continue to collaborate with NYGB, other financial parties, and developers to ensure that necessary financial and performance metrics from deployed projects are collected, validated, and available for review on the NYSERDA Distributed Energy Resource Portal[61] – as part of the soft cost reduction strategy described above. Staff also support all efforts to streamline this data into readily sortable fields and presenting use cases and best practices. The distribution utilities, NYPA and LIPA should also provide NYSERDA with non-proprietary performance and financial data on any energy storage projects providing distribution relief such as non-wires alternatives.

Path Forward

- In anticipation of market activity and in conjunction with the release of the NYS Energy Storage Roadmap, NYGB has issued an RFI: Financing Arrangements for Energy Storage Projects in New York State. The purpose of this RFI is to invite energy storage market participants to engage in conversations with NYGB to learn more about specific ways in which NYGB can most effectively invest at least $200 million to generate market activity, enable scale and drive standardization.
- NYPA should continue to pursue procurements on behalf of its customers, as described further in the Lead by Example section. Staff recommends that multi-year procurements be developed and issued before the end of 2018 so that projects can begin construction in 2019 and 2020.

[61] *See* NYSERDA DER Integrated Data System, available at: https://der.nyserda.ny.gov/.

- Staff recommends that NYSERDA facilitate discussions with EIC and NYCEEC to bring clarity to the developer and customer community around Commercial PACE financing opportunities, with projects being financed by C-PACE by early 2019.

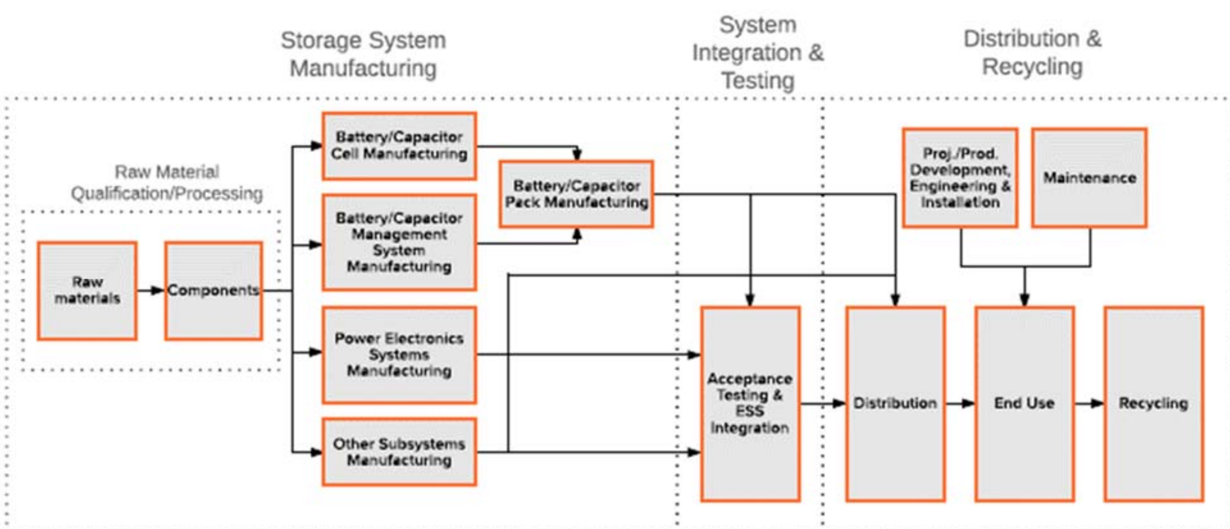
4.5.3 Workforce Development

Background

A pipeline of skilled workers is essential to ensuring that the Governor's directive to grow the energy storage sector to 30,000 jobs by 2030 is realized, from almost 4,000 employed today. This requires a readily available workforce that is skilled and adaptable. The storage sector includes a wide range of traditional and emerging markets including transportation, stationary storage, and electronics. New York State companies span product development and manufacturing, system integration, sales, service and control systems. Depicted in the figure below is a simplified energy storage supply chain including manufacturing, installation, service and recycling. This highlights the range of talents that will be required to fully build this sector, offering clear opportunities for apprenticeship and internships, higher education partnerships, and training. For the new and existing workforce, these needs are amplified by a shortage of skilled workers due to attrition from retirements and changing technology demands requiring upgraded skills.

The figure below shows a simplified battery/energy storage supply chain diagram.[62]

Figure 13. Battery/Energy Storage Supply Chain



Recommendations

Staff recommends that NYSERDA work with the NYS Department of Labor, Empire State Development Corporation, and training partners including SUNY, CUNY, and labor unions through an industry partnership approach to:

[62] *See* The Energy Storage Industry in New York State: Recent Growth and Projections, 2015 Update, available at: https://www.nyserda.ny.gov/-/media/Files/Publications/PPSER/Program-Evaluation/2016ContractorReports/2016-10-energy-storage-industry-growth-projections-report.pdf.

- Inventory specific worker skills that will be required by businesses throughout the energy storage supply chain, specifically focusing on design and engineering, installation and service, and utility planning and dispatch.
- Map required skills to existing training and the existing labor pool, including both new workers and existing workers) to identify gaps and shortages.
- Work with these stakeholders to develop a blueprint that will ensure a talent pipeline or workers with the necessary skills.
- Identify gaps in training infrastructure and capacity in areas such as curriculum, trained trainers, training equipment, job placement initiatives, on-the-job training, internships, apprenticeships, career pathway training, certifications, etc.
- Workforce development efforts should include opportunities to support disadvantaged workers including youth (18-24), displaced and dislocated workers, women, minorities and veterans.

Path Forward

- NYSERDA should facilitate an industry partnership to work with State and local partners, industry, and other stakeholders to develop an inventory of needs by spring 2019 and a blueprint for addressing potential skilled talent shortages for consideration by fall 2019.

4.5.4 Data Access

Background

Data accessibility is largely driven by the utilities' DSIPs and the adopted Benefit Cost Analysis (BCA) handbook. The following is an illustrative list of the main data sources currently available that support energy storage deployments:

- Hosting capacity maps are currently being published.[63] The hosting capacity maps are the only publicly accessible online distribution system maps available from the utilities. Types and granularity of information presented in the maps are approximations of areas where DER interconnection would be comparatively costly. The maps have the potential to serve as a platform for providing more useful system data. Staff guidance for the utilities' 2018 DSIP updates calls for increasing frequency of updates to the hosting capacity maps over time. Staff guidance also calls for development and presentation of hosting capacity forecasts, which look ahead 3-5 years. The utilities' current hosting capacity analyses are performed with EPRI's DRIVE tool and do not yet address non-solar DERs including storage, though forthcoming updates of DRIVE will.
- "Green Button Download My Data" is available in Con Edison's service territory.[64] This allows a customer to more easily download their load profile data and share it. Green Button Connect allows utility customers to automate the secure transfer their own energy usage data to authorized third parties, based on affirmative (opt-in) customer consent and control. All of the utilities have committed to implementing Green Button Connect in a timeframe which generally corresponds with their respective advanced metering initiative (AMI) deployments.
- Aggregated customer information is included in NWA procurements, including the number of each type of customer, total kWh consumption for each customer class, kW peak load for each

[63] *See* The Joint Utilities of New York, Utility Specific Hosting Capacity, available at: http://jointutilitiesofny.org/utility-specific-pages/hosting-capacity/.

[64] See Con Edison's Download Your Energy Data tool, available at: https://www.coned.com/en/save-money/estimate-your-energy-usage/make-better-energychoices-with-green-button.

customer class, and average kW demand for each customer class. The data provided does not support identification of individual customers who would be good candidates for energy storage.

- Streamlined public access to aggregated community-scale utility energy data is now being developed under the Utility Energy Registry (UER), which may assist the identification of Community Choice Aggregation (CCA) opportunities. UER will not include distribution system data or customer-specific data.
- NYPA's New York Energy Manager (NYEM) platform contains energy usage data for 11,000 (and growing) customer buildings that can be used to help determine the potential value, optimal size and management and potential aggregation of storage projects.
- Certain publicly available datasets are available to vendors looking for information on a customer, including New York City Local Law 84 (LL84), New York City Primary Land Use Tax Lot Output (PLUTO), and others.
- NYSERDA's energy storage program is funding feasibility studies and field demonstrations of energy storage systems through PON 1746 and PON 3541[65], and has engaged with Cadmus to make certain data sets from deployed projects publicly available.[66] NYSERDA's energy storage program is also funding direct technical assistance on energy storage deployments for customer and industry stakeholders that seek market information or high-level analytical data on potential installations.
- Con Edison's buildings efficiency REV-demo provides a platform that analyzes interval meter data to identify high potential projects (a "remote audit") that can be put out to bid.

In addition to the above, certain key challenges exist regarding data accessibility, which include, but are not limited to, the following:

- The existing meters installed at the vast majority of residential and small commercial customer premises in New York State do not collect the granular energy consumption and demand data needed for accurate load profiling and demand-sensitive billing. The utilities' respective AMI deployment plans differ significantly. Based on the current outlook and circumstances, full statewide AMI deployment might not be achieved until 2025 or later.
- Generally, authorized third parties do not yet have utility-provided resources which enable them to efficiently access detailed customer load profile data (i.e., 12 months of load at 15-minute intervals), where the data exists. An exception is at Con Edison where access to customers' interval data works comparatively well. Data access is also necessary from governmental customers, therefore NYPA should be engaged to identify ways in which such access, with customer permission, can be provided to third parties.
- Developers need more distribution system data to enable them to independently identify and evaluate system needs. Utilities expose DER deployment opportunities and related data through NWA procurements; however, current utility resources and practices do not provide developers with the data needed for independent analyses and long-term planning.
- There is a lack of published, third-party verified, field data describing the performance of deployed DERs, including storage. Such real-world data is essential for developers, financiers, and customers for increasing the certainty of savings and/or revenue of a proposed installation. As stated above, NYSERDA will be providing independently verified field data from NYSERDA-

[65] *See* NYSERDA's Energy Storage Program website, available at: https://www.nyserda.ny.gov/All-Programs/Programs/Energy-Storage-Program.

[66] *See* NYSERDA DER Integrated Data System, available at: https://der.nyserda.ny.gov/.

supported projects. Likewise, NYPA will work to capture and share data from its storage projects to provide performance data to the market – proving full value of services, informing regulatory agencies, and building longer-term confidence among market participants.

Recommendations

- Provide specific guidance for utilities on how to align plans, resources, and services regarding access to distribution system data and customer data.

Path Forward

<u>Access to Distribution System Data</u>
To ensure the 2025 target is met, the following datasets should be made available within 12 months following Commission action on this Roadmap. Further, to successfully implement the integrated planning, advanced forecasting, distribution system data access, and energy storage integration requirements for utility DSIPs, these actions should be described:

- The utilities should provide DER developers and other stakeholders with detailed monthly capacity and production data – actual and forecasted up to 5 years – for existing peaker units with low capacity utilization. The data will help developers identify peaker locations that could be good candidates for storage.
- The utilities should provide DER developers and operators with hourly load data – actual and forecasted – for substations that connect the distribution system with the bulk electric system (transmission nodes). The data will inform DER development and operation decisions that can help the utility peak-shave at the right times and locations, thereby lowering the utilities' ICAP tags and creating opportunities for energy storage deployments.
- The utilities should increase and improve the distribution system data provided to DER developers/operators. This is a significant part of the Staff guidance for the utilities' 2018 DSIP Updates. Specific types of data which are particularly useful for planning and operating energy storage resources include:
    - Substation locations and equipment ratings
    - Locations and ratings of distribution circuits and equipment
    - 8,760 load curves for substation buses and feeders
    - Existing and predicted load locations and attributes (customer category, utility rate, average demand, peak demand, peak time, "peakiness")
    - Existing and predicted DER locations and attributes (type, ratings, configuration, use case, year deployed)
    - Where, when, and how predicted power flows would violate operating limits of the existing distribution system
    - Capital deferral timeframes for potential NWAs

<u>Access to Customer Data</u>
To successfully implement the integrated planning, advanced forecasting, customer data, and energy storage integration requirements for utility DSIPs, the utilities should increase and improve the customer data provided to DER developers/operators. This is a significant part of the Staff guidance for the utilities' 2018 DSIP Updates. To ensure the 2025 target is met, within six months following Commission action on this Roadmap:

- All of the utilities should expedite their plans to implement "Green Button Connect My Data" (or equivalent) and should provide synthesized load profiles for customers who are not yet equipped with interval meters. Prior to having the ability to record a customer's actual interval consumption data with an advanced interval meter, the customer's monthly energy consumption and a generic load shape for the customer's respective category can be utilized for an approximation of the customer's interval data.

- All utilities should expedite their AMI deployments and identify how they are prioritizing AMI deployment and to what extent "high value customers" are being prioritized. Examples of high value customers are customers with high demand, customers that are under Con Edison's Rider Q tariff or the Value of Distributed Energy Resources tariff, or customers that install DERs or drive electric vehicles.
- NYSERDA and DPS should lead coordination efforts with the Joint Utilities, and LIPA/PSEG to develop and issue a solicitation for a third-party to develop, implement, and maintain a searchable data platform containing customer-related data. The platform would then assist DER developers with identifying potential candidates for energy storage and/or other DERs. Customer-related data provided in the platform should include load profile attributes (average load, average peak, peak times, load factor), current tariff/program, NAICS code, building size, NYISO zone, substation, circuit, installed type(s) of DER, hosting capacity, etc. Means and methods for protecting customer privacy (i.e., anonymized records, opt-in/opt-out mechanisms, and customer contact protocols) and for monetizing customer acquisition services the utility provides to the data platform should be described fully and clearly in the solicitation. The following schedule is recommended: (1) within six months of Commission order, determine which entity is leading and issuing the solicitation, refine the specific features and data fields that will be included on the platform, resolve policy decisions including customer privacy, and determine the process for identifying customers with their consent that are identified by DER providers; DER providers shall also be consulted to maximize the usefulness of the platform; (2) in months 7-12, issue the solicitation, review proposals, and select a vendor; (3) by month 18, a beta version of the platform should be established with testing underway so that it is available for use by developers by summer 2021. If prioritization of customer types is necessary, demand metered customer data shall be prioritized initially in populating the platform over mass-market customers.

4.6 "Clean Peak" Actions

Background

As greater levels of intermittent renewable energy are brought online, reducing ramping rates and ensuring that clean resources are available to meet periods of peak electric demand and not curtailed will become more significant. A number of prior recommendations are each designed to help facilitate a shift toward meeting peak demands with clean energy, including:

- Differentiating the E value in the VDER value stack to reflect time of day/season marginal carbon emissions (Section 4.1.4)
- Procuring Utility non-wires alternative solutions that defer utility T&D investment and also reduce peak system loads; these peaks usually occur during periods of largest carbon and nitrogen oxide emissions (Section 4.3.1)
- Calibrating the proposed market acceleration bridge incentive to maximize carbon reduction based on aligning with system peak load (Section 4.4)
- Continuing to encourage energy storage pairing with Large Scale Renewables under NYSERDA's Renewable Energy Certificate procurements (Section 4.3.3)

- Additional actions are proposed in this section, specifically addressing the oldest of the downstate peaker fleet units, many of which are approaching the end of their useful lives, and all of which would be governed by NO_x regulations, which would be proposed and promulgated by DEC.

Other mechanisms to enable cleaner generation to meet periods of peak electric demand were also examined, including flexible capacity credits. Such a program could be designed to compensate for non-market benefits provided by fast acting non-emitting dispatchable resources while also providing revenue visibility for developers. A number of potential system benefits were suggested and examined including avoided generator startup costs, avoided incremental transmission costs, avoiding natural gas pipeline constraints during peak winter days, avoiding local criteria pollutant emissions and greenhouse gas emissions, and increasing renewable hosting capacity/reducing curtailment. Several of these system benefits would be compensated through mechanisms recommended in the Roadmap. Staff is interested in stakeholder input on approaches that could appropriately assign value to flexible resources including storage, and in allowing these resources to meet the peak electric requirements of the system.

Specifically, there are over 3,000 MW of conventional generation units in Zone J and Zone K (i.e., New York City and Long Island) that have low utilization (generating electricity less than 5 percent of the year); are approaching an average of 50 years of age; and are generally used for meeting periods of high electric demand or for reliability purposes. These units primarily provide "peaker" services: capacity to meet NYISO locational and system capacity requirements, and other, more local (i.e., utility-level) reliability-based services such as contingency reserves.[67] Many of these downstate peakers are dual-fuel and may be required to burn oil or kerosene in the winter due to reliability rules and/or fuel constraint concerns to relieve demand on the natural gas system.

Furthermore, DEC's pre-proposal stakeholder draft of simple cycle combustion turbine (peaker unit) nitrogen oxide (NOx) emissions regulations, released to stakeholders for comment on June 4, 2018, included a potential phase in of regulatory requirements between 2023-2025.[68] These regulations could have an impact on the future state and availability of these units and DPS/NYSERDA Staff intend to continue to coordinate closely with DEC Staff as these proposed rules are developed.

A high-level screening analysis of downstate peakers was performed by E3 (further detail is in Appendix H) to determine whether any generation units had characteristics that would make them potential candidates for hybridization[69], repowering[70], and/or replacement with energy storage systems. This analysis examined the operational profiles of these units based on 2015-17 generation data[71] and was

[67] Contingency reserves are required for continuing to meet uninterrupted electric service if major transmission or distribution lines or generating assets are removed from service due to unplanned outages.

[68] *See* Simple Cycle Combustion Turbine (Peaking Unit) Stakeholder Draft (June 7, 2018) available at: http://www.dec.ny.gov/docs/air_pdf/scctdraft.pdf.

[69] Hybridization involves installing energy storage at an existing conventional site that can either be charged from the on-site generating unit or enhance the operations of the existing conventional unit(s) Hybridization allows the site to operate at a higher efficiency, with more flexibility in minimum generating requirements, faster ramping, and/or ability to participate in certain ancillary services markets like regulation or 10-minute sync.

[70] Repowering is the process of replacing older generating units/facilities with newer ones at the same site that are either more efficient, increase the power generated, or involve newer technology like advanced energy storage and/or renewables.

[71] The three data sources for this analysis were NYISO Planning Documents for 2017 NYCA Generation Facilities; EPA Air Markets Program Data for 2015-2017; and SNL Financial (S&P Market Intelligence). Note that the EPA dataset is incomplete; for a subset of units, operation data is only reported from April to September and does not include CO_2 or SO_2 emissions.

done from a purely *ex post* operational screening perspective.[72] The screening methodology separated downstate peaking units into three groups based on their respective observed operational characteristics:

- Group 1: Peaking units that never run more than 4 hours.
- Group 2: Peaking units that average less than 4 hours per start but may run more than 4 hours.
- Group 3: Peaking units that always run more than 4 hours.

Several key takeaways emerge from this analysis:

- Many peaking units have high operating costs and run less than 4 hours per start, making them potential candidates for hybridization, repowering, and/or replacement.
- The makeup and composition of the Groups vary year-to-year, where Group 1 ranged as low as 301 MW in 2016 and high as 788 MW in 2017.
- The average characteristics of Group 1 and Group 2 peaking units remained very similar across the years included in this analysis (2017, 2016, and 2015).
- It is important to distinguish between facility-level and unit-level operations. While some facilities on an aggregate basis may often run more than 4-hours per start, individual units within those facilities often run much less.
- Group 1 and 2 peaker units produce approximately 55 percent of the NO_x and SO_2 emissions of Group 3, while only producing approximately 13 percent of the generation of Group 3 due to much higher emission rates in Group 1.
- The locations of Group 1 and Group 2 peaking units were highly correlated with Environmental Justice (EJ) areas, particularly near New York City. These units produce twice the carbon emissions and twenty times the NO_x emissions per unit of energy generated as compared to a typical thermal plant. In addition, they generally operate during extreme weather events – emitting SO_x, NO_x and particulate matter and contributing to ground-level ozone, which causes asthma and other health impacts.

Recommendations

- Create a multi-stakeholder process to develop a methodology for analyzing peaker operational and emission profiles on a unit-by-unit basis to determine which units are potential candidates for repowering or replacement by storage to allow emission reductions and system cost efficiencies. Going forward, peaker profiles may change based on future environmental regulations, contract renegotiations, and other factors requiring further study and examination (including expected retirements).
- This analysis should also include a series of Reliability and Operational Assessment Studies looking at the equivalent level of "clean resources" that could provide the same level of reliability as the existing peaker units, considering current operational practices and explicitly factoring in new potential operational and regulatory paradigms. Hybridization and repowering with storage as well as replacement with stand-alone storage should be explicitly examined, especially in the context of more stringent emission standards. This is critically important and must consider all applicable reliability requirements so that future system planning and contingency/reliability requirements consider DERs including, but not limited to, storage.
- Utilities directly impacted by the DEC NOx regulations under development should be ordered to develop a "Peaking Unit Contingency Plan," that takes into account the results of the analysis from

[72] No consideration was given to contracting and financial arrangements nor to the reliability planning and local reserve requirements that may be applicable to individual facilities and/or specific units.

the preceding recommendations, to address the potential retirement of these significant generation facilities, similar to that which was required by the Commission in Case 12-E-0503 for the Indian Point Contingency.[73]

- Other mechanisms to enable cleaner generation to meet periods of peak electric demand should continue to be examined, including flexible capacity benefits that reduce greenhouse gas emissions and increase renewable generation.

Path Forward

- Stakeholders including the New York Joint Utilities, the NYISO, DPS, DEC and NYSERDA should work together to perform the recommended analysis above. This includes determining how many MWs of peaking units could be replaced or repowered economically with storage at varying durations (i.e., 4, 6, and 8 hours) without threatening system and/or local reliability, under both existing operational practices as well as alternate practices that would increase reliance on energy-limited resources. In addition, the analysis should include quantifying the benefits of peaker replacement such as avoided fuel, O&M, capacity, emission costs (monetized and unmonetized) over the life cycle of the facility, versus alternative "clean energy" portfolio costs that include various storage configurations (such as hybridization, repowering, and/or replacement). Staff recommends that the study results be presented to the Commission by July 1, 2019.
- Con Edison and LIPA to collaborate with DPS Staff, and any other appropriate entities, to produce a Peaking Unit Contingency Plan that incorporates results from the Reliability and Operational Assessment Studies to be submitted to the Commission by July 1, 2019.

4.7 Wholesale Market Actions

4.7.1 Bulk System Focus

Background

Significant barriers stand in the way of widespread use of energy storage for services to the bulk electric system. This is true despite development of several key NYISO rules, programs and capabilities to accommodate the limited energy/duration nature of storage (i.e., ELR for capacity and LESR for frequency regulation with state-of-charge management). Generally, the existing bulk system is structured for large resources (typically on the scale of hundreds of MWs) that have an unlimited run time, are interconnected to the transmission system and participate only in the wholesale market. These recommendations recognize the significant work already underway at the NYISO and in meeting FERC Order 841 compliance. Staff, however, recommends that serious consideration be given to accelerating adoption of these recommendations within the NYISO process and including the dual market participation model with the FERC 841 tariff filing that will be submitted by the NYISO later this year.

Recommendations

- Capacity market changes that are more flexible in duration and size: Currently, energy storage must have a duration of 4 hours and power rating of at least 1 MW to qualify as a capacity supplier under the Energy Limited Resource (ELR) program. The following are several recommended

[73] Case 12-E-0503, Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans, Order Instituting Proceeding and Soliciting Indian Point Contingency Plan, (Issued November 30, 2012).

NYISO actions to better enable the unique characteristics of energy storage to meet capacity requirements:

- Establish a manner to value and enable participation of shorter duration (1 to 4 hour) storage resources that can be available during summer and winter capability periods and examine the relative system value that varying durations can provide.
- Evaluate whether procuring a portfolio of both long (unlimited) and short duration (1 to 4 hours) capacity resources can be a more efficient and flexible way to meet system peak energy needs while maintaining reliability.
- Consider the optionality that short duration capacity resources can provide in meeting energy needs during system peak given the probability of various durations. Longer duration or unlimited capacity resources could be held in reserve for long duration peaks.
- Allow storage resources to be aggregated zonally in the capacity market to achieve higher durations and increased revenue opportunities (if available).
- Determine whether fast-responding resources like energy storage can be more valuable than resources that have longer start-up times.
- Energy storage participation as capacity should only be assessed penalties where justified by operational requirements without artificial de-rating based on duration or required charging. Storage's capability as a capacity resource for near-instantaneous response should also be valued.
- Ensure that any energy storage assets that provide capacity are able to participate in other NYISO markets consistent with Order 841.

- <u>Exempt energy storage from buyer-side mitigation rules</u>: Recent proposals by the NYISO to subject energy storage resources in mitigated capacity zones to buyer-side mitigation measures could result in the wholesale markets failing to accommodate legitimate State policy interests such as those effectuated by this Roadmap.[74] Exposing new storage resources, which have no evidence of an ability to manipulate capacity prices, to buyer-side mitigation exposes these resources to the potential of not receiving capacity revenues depending upon how the mitigation tests are applied. Buyer-side mitigation poses a potentially enormous barrier to wholesale market entry for energy storage resources. Enabling energy storage assets access to meet all wholesale market needs for which the asset is capable of providing (consistent with FERC Order 841) and appropriately compensating it for these services, is imperative for many reasons, including accessing third party financing. Exposing energy storage resources of any size to the potential of mitigation will lead to increased consumer costs and decreased system efficiency. At a minimum, the NYISO should propose an exemption from buyer-side mitigation for energy storage resources under a certain size threshold (e.g., 20 MW), as resources of this size will not have the ability to artificially suppress capacity prices. It is also recommended that storage resources deployed on the distribution system and primarily performing a distribution service or operating under a distribution tariff be exempted from mitigation, should they also qualify to be a bulk market capacity resource.

- <u>Develop a participation model for short-duration storage providing Ancillary Services</u>: The NYISO should consider a participation model for short-duration storage to provide both reserves and frequency regulation with NYISO-provided state-of-charge management. Certain types of energy storage, such as batteries, are highly responsive and accurately dispatchable for short-term grid

[74] *See* NYISO Presentation: Capacity Market Rules for Energy Storage Resources (May 23, 2018), http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2018-05-23/Initial%20ESR%20Capacity%20Model.pdf.

reliability ancillary services products like spinning reserves and frequency regulation. The NYISO allows storage to provide frequency regulation in the LESR program, which accommodates storage's limited amount of available energy by managing the resource's state of charge. However, the current LESR program does not allow storage to provide both regulation and reserves, limiting use of many assets.

- Encourage the development of new wholesale market products or improve existing products to reward resources that are flexible and can respond quickly: One option the NYISO should pursue is a fast-ramping product. The NYISO has identified that some future scenarios of high renewable penetration result in situations where fewer resources with ramping capabilities would be available for dispatch. Storage resources can provide accurate and reliable ramping service better than any existing alternative and, even when paired with existing fossil fuel plants, can improve overall system efficiency and utilization.
- Energy Storage as a Bulk Transmission Resource in NYISO Planning**:** The NYISO and PSC should modify transmission planning processes to incorporate consideration of energy storage in addressing transmission needs and public policy objectives. New York's transmission planning process and the manner of cost recovery and compensation limits the consideration of energy storage as a solution to transmission needs.[75] The NYISO generally looks at energy storage as a type of generator with the grid as its fuel. If storage were proposed as a solution to a transmission need, the current NYISO tariff likely classifies energy storage as non-wires alternatives, which fall outside of the ISO, and FERC jurisdiction does not allow for cost recovery of non-transmission assets. However, FERC has clearly stated that energy storage qualifies as transmission and should be compensated as such when it fulfills a transmission need. Energy storage could provide especially valuable flexibility as New York transitions to higher penetrations of renewables, serving as an alternative transmission solution that may defer large transmission investments until more renewable generation resources are located and developed. This could also provide optionality in transmission planning given the uncertainty of changes to load including energy efficiency, EV penetration, and other forms of beneficial electrification. The Commission could also consider ensuring that energy storage is included in the Public Policy Transmission Needs Assessment process and make storage projects eligible for cost allocation and recovery.
- Pairing with bulk renewables: NYISO requires intermittent wind generators to provide the NYISO the ability to curtail output. NYISO has proposed the same requirement for solar generators. Curtailment results in a significant loss of revenue to renewable generators and the energy, instead of being curtailed, could be stored. Energy storage paired with an intermittent generator would enable the facility to follow NYISO dispatch down and up for a limited duration. However, adding storage to an intermittent renewable generator behind the same point of common coupling, though technically allowed, is exceedingly impractical due to NYISO rules. Developers avoid adding storage because this changes the project's generation type to "Dispatchable" and voids the project's eligibility for Intermittent Generator exemptions. A new participation model should allow energy storage, but effect only that portion equal to the nameplate power rating of the storage system, rather than losing 100 percent of the facility's Intermittent Generator treatment.

[75] 18 CFR Part 35 (2017). *See* also Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery, Policy Statement (issued January 19, 2017); and Western Grid Development, LLC, Docket No. EL10-19-000, Order on Petition for Declaratory Order (issued January 21, 2010).

- Aggregation and infrastructure requirements appropriate for smaller resources: The NYISO and utilities should seek more cost-effective dispatch and telemetry solutions for smaller and distributed resources to meet NYISO infrastructure requirements, particularly Order 841 requirements to allow 100 kW assets to participate in bulk markets. NYISO requires bulk resources to maintain connections and interoperation between the resource control center, the transmission owner, and the NYISO. This requirement can cost hundreds of thousands of dollars in infrastructure, which may be appropriate for bulk generators but will preclude many smaller assets from providing wholesale services.
    - Staff recommends that the NYISO initially determine an appropriate amount of grid connected energy storage resources that may use 'direct to NYISO' telemetry and dispatch infrastructure as is currently done under their Demand Side Ancillary Services Program.
    - A working group, inclusive of NYISO, DPS, NYSERDA, industry and utilities, should specify and test a more cost-effective and scalable manner of telemetry and dispatch interoperation for small resources. This should be done immediately so that the methods can be tested on the DSIP-required utility energy storage projects and REV energy storage demonstrations. This should include cloud-based alternatives that can scale and provide more reliable interoperation.
    - This working group should also specify standard requirements for telemetry and dispatch systems of aggregations of smaller resources. Alternatives to real-time telemetry of small component resources within an aggregation should be examined within the NYISO's DER Roadmap.

Path Forward

- The NYISO recently released its State of Energy Storage report in December 2017 followed by a draft of its Master Plan in May 2018. In the Draft Master Plan, the NYISO states that the Energy Storage Participation Model design will be complete in 2018 with deployment by the end of 2019. There will be a corresponding compliance filing on electric storage participation to comply with FERC Order 841 which is expected in Q4 2018.
- Staff also recommends that the NYISO include the rules to enable dual market participation with its FERC Order 841 compliance filing. Market rules for aggregation of storage resources should also be considered expeditiously so that this filing may be made in 2019. The second phase of Energy Storage Integration described in the Draft Master Plan will be the Renewable and Energy Storage Aggregation Model. This phase is planned to have Market Design complete in 2020 and deployment by 2023. Staff encourages this timeline to be accelerated, or for the NYISO to develop pilot approaches that can be implemented during the pendency of final market design rule changes (e.g., up to a certain capacity).
- DPS and NYSERDA Staff will continue to provide input to the NYISO as stakeholders regarding FERC Order 841 compliance tariff filing related to the recommendations above and continue to seek a FERC filing enabling dual-participation in parallel with the Order 841 compliance filing.
- Staff also recommend continued active participation of DPS and NYSERDA Staff in all of the applicable NYISO working groups, to both avoid unnecessary barriers to energy storage development, and to introduce/advocate for any new products or changes to existing products that may facilitate appropriately valuing energy storage resources and specifically advocate for the recommendations above.

4.7.2 Dual Market Participation

Background

This Roadmap also sets forth a vision where energy storage would be deployed in the distribution system and with load where, in some applications, storage systems could also provide services to the bulk system, particularly dispatchable services. New York State's distributed energy policy has created an eligibility, tariff and "value stack" framework by which distributed resources can be connected and compensated for the value added to the electrical system. DERs and energy storage may be connected with retail load or standalone and receive appropriate retail values, including energy, capacity and environmental attributes. However, distributed energy storage should also be allowed to provide separate and distinct services to the bulk market, similar to how demand response resources participate both in utility programs and at the NYISO.

Because of its unique capabilities, distributed energy storage should be allowed to provide bulk dispatchable services while also providing its local service, where those services do not conflict. Energy storage installed on the distribution system and compensated for local values should be allowed to use its spare capacity or uncommitted schedule to provide bulk ancillary services such as reserves and regulation. Two use cases most impacted by this issue include 1) PV and storage resources being compensated for energy and capacity under a VDER tariff, but capable of also providing Ancillary Services especially during the non-summer months and 2) storage providing a distribution reliability service, that may otherwise provide capacity, energy and ancillary services in bulk markets.

Energy storage in the distribution system should be allowed to provide separate and distinct services to both the utility and the NYISO. Additionally, distributed energy storage operating under a distribution tariff, without obligation to the utility should be allowed to provide bulk market services. Such a market participation model should be permitted as long as assets are not compensated twice for the same service. It is imperative that these dual market participation and aggregation rules, including coordination of various tariffs, are established as soon as possible. Staff recommends that this be prioritized so that a dual market participation model accompanies the NYISO's tariff filings in 2018 to comply with FERC Order 841. Without these participation rules established, these roadblocks will remain.

Better Accommodating Participation of Distributed Storage Resources

The NYISO should create participation models for distributed storage resources to participate in the bulk market when the resource is not being used to meet a local need, as under an NWA contract with the distribution system operator. Energy storage can be deployed in the utility's distribution system, often in applications (i.e., NWAs) that require service or operation only during prescribed times. When not used for those local services the storage could perform a service for the bulk system, but the inability today to provide separate and distinct services both at the distribution level and bulk markets limits the competitiveness of energy storage in these applications and can create a burden on ratepayers. The NYISO and utilities should address the prohibition on dual market participation. Key changes would enable storage resources developed for VDER, NWA, or other applications connected at the distribution system, but not associated with load, to also participate in all bulk services it may qualify for.

Recommendations

- Enable storage resources to participation in bulk and retail markets by avoiding duplicate payments: The NYISO should make changes that enable energy storage to provide both distribution and bulk system value, while ensuring it isn't compensated twice. For example, NYISO should allow distributed storage to provide ancillary services, receive a reservation payment, but forgo energy compensation from the bulk market when those resources are receiving a retail energy payment (i.e., VDER).

- Accommodate periods of unavailability: The NYISO should develop rules and procedures for resources that are available less than year-round. This includes addressing settlement, meter data and telemetry handling procedures for distributed resources and storage that periodically provide a local service. NYISO market participation assumes that resources are full-time bulk suppliers. In some cases, storage on the distribution system will need to prioritize local functions for periods (i.e., months or seasons as with NWA function or shifting energy for VDER) over providing bulk services. Enabling less than full-time bulk participation could be accomplished on an hourly, day-ahead, seasonal or capability period basis. NYISO should accommodate both scheduled and unscheduled unavailability in a manner consistent with existing unavailability rules applied to other generators. Maintaining local retail reliability services could be accomplished by utilizing existing procedures for local reliability such as Supplemental Resource Evaluations.
- Retail/wholesale coordination of charging of storage serving the bulk market: DPS, NYISO and the transmission owners should engage stakeholders on an appropriate construct to allow energy storage on the distribution system to participate in bulk markets with appropriate implementation of commodity costs and retail delivery tariffs. The FERC Order 841 requires that storage providing a bulk service be able to charge at wholesale commodity costs.
- The Commission should adopt principles for dual participation of storage as well as other DERs (if applicable and appropriate).[76] The adopted principles should be incorporated into the Market Design and Integration Report described below. Staff recommends the following:
  - Resources interconnected in the customer segment may provide services in any segment.
  - Resources interconnected in the distribution segment may provide services in all segments except the customer segment, with the possible exception of community energy resources.
  - Resources interconnected in the bulk segment may provide services in all segments except the customer or distribution segments.
  - Resources interconnected in any grid segment may directly or indirectly provide bulk system services like transmission and wholesale market services.
  - If one of the services provided by a DER is a reliability service, then that service must have priority. Furthermore, a resource interconnected in the customer segment must give first priority to customer reliability, second priority to distribution system reliability, and third priority to bulk system reliability. Likewise, a resource interconnected in the distribution segment must give first priority to distribution system reliability, and second priority to bulk system reliability.
  - Priority means that a single DER must not enter into two or more reliability service obligation(s) such that the performance of one obligation renders the resource unable to perform the other obligation(s). New agreements for such obligations, including contracts and tariffs, must specify terms to ensure resource availability, which may include, but should not be limited to, financial penalties.
  - If using different portions of capacity to perform services, DER providers must clearly demonstrate, when contracting for services, the total capacity of the resource, with a

[76] For the purposes of this Roadmap, the term "Multi-Segment Services" encompasses the full range of beneficial functions that a DER, based on its location and capabilities, can provide in various market segments defined as customer-sited, distribution system, and/or bulk system. This includes, but is not limited to, any of the various definitions of "dual participation" and does not prescribe any particular framework for coordinating a DER's services across segments.

guarantee and means to verify that a certain, distinct capacity is dedicated and available to the capacity-differentiated reliability services.

- For each service, the program rules, contract or tariff relevant to the segment in which the service is provided must specify enforcement of these rules, including any penalties for non-performance.
- In response to a utility request for offer, the DER provider is required to list any additional services it currently provides outside of the solicitation. In the event that a DER is enlisted to provide additional services at a later date, the DER provider is required to provide an updated list of all services provided by that resource to the entities that receive service from that resource. The intent of this principle is to provide transparency in the DER market.
- For each service provided, the DER must comply with availability and performance requirements specified in the DER provider's contract with the service recipient.
- In paying DERs for performance of services, compensation and credit may only be permitted for those services that are incremental or distinct. DER services provided must be measurable, and the same service only counted and compensated once to avoid double compensation.

Path Forward

- DPS and NYSERDA Staff will provide input to the NYISO on its FERC Order 841 tariff filing related to the recommendation above.
- DPS and NYSERDA Staff will continue to push for a FERC filing enabling dual participation in parallel with the Order 841 compliance filing.
- Continued active participation of DPS and NYSERDA Staff in all of the applicable NYISO working groups, to both avoid unnecessary barriers to energy storage development, and to introduce/advocate for any new products or changes to existing products that may facilitate appropriately valuing energy storage resources and specifically advocate for the recommendations above.
- Commission adopts principles that are recognized by the Joint Utilities and NYISO when developing retail and wholesale market products and services.

4.7.3 Distribution and Wholesale Market Coordination

Background

<u>Better Accommodating and Utilizing Energy Storage Connected to Electric Distribution Systems</u>

With the right policy and technical frameworks in place, energy storage deployed in the electric distribution system can perform multiple functions that benefit the bulk electric system while also supporting distribution system needs and/or customer objectives. Many energy storage resources in the distribution system could be in the range of 1 MW to 20 MW; however, most are likely to be smaller, often well below 1 MW. Importantly, the smaller resources are expected to be numerous and would be capable of providing meaningful bulk system services when organized and operated in aggregations.

As part of the DSIP process, the Joint Utilities are responsible for preparing and filing a "Market Design and Integration Report" describing the utilities' shared plan for designing, implementing, and managing DSP market functions that will enable DER participation in both the distribution and bulk system markets. Issues of visibility into a storage asset's state of charge, control, coordination and dispatchability must be addressed in coordination with the utilities and the NYISO. It is expected that the utilities' plan will establish a well-integrated framework for coordinating DER planning, operation, and compensation so as to optimize the use of energy storage resources for multiple purposes. This will include determining the detailed functionalities, and corresponding operational and management systems, needed to implement the market-coupling framework.

Recommendations

To inform the utilities' Market Design and Integration Report, a working group should be established comprising appropriate contributors from the Joint Utilities, the NYISO, DPS, and NYSERDA to develop a schedule to accomplish the following tasks:

- Determine the information and capabilities that the *NYISO* needs for planning, dispatching, measuring, and compensating each type of wholesale service that a resource can provide.
- Determine the information and capabilities that the *utilities* need for planning, dispatching, measuring, and compensating each type of service that a resource can provide to the electric distribution system.
- Determine the needs and priorities, both technical and economic, for coordinating DER operations from the perspectives of the NYISO, the utilities, and the DER operators.
- Identify and evaluate alternative approaches for integrating and optimizing the use of DERs for both bulk and distribution services.
- Identify and evaluate alternative approaches for determining and allocating the economic costs and benefits of bulk system effects attributable to DERs. For example, examine how DER use cases and compensation mechanisms might affect and/or be affected by different approaches to allocating capacity requirements to load serving entities.
- Consider different combinations of roles and responsibilities for the NYISO, the utilities, and DER operators. For example:
    - Examine the advantages/disadvantages of the NYISO monitoring, dispatching, billing, and compensating DERs participating in the wholesale market.
    - Examine the advantages/disadvantages of the utility having sole responsibility for monitoring, dispatching, billing, and compensating DERs.
    - Determine how FERC Order 841 affects the use of DERs for bulk system services.
- Establish DER metering, telemetry, and dispatch policies to ensure efficient optimization and coordination of energy storage services for both the bulk and distribution systems.
- Identify and develop approaches for fast-tracking energy storage applications in which use of the resource for both distribution and bulk system services does not require operational coordination.
- Ensure that the existing compensation framework fully and fairly compensates energy storage resources for multiple value streams benefitting the bulk and distribution systems but prevents double payments for single services. For example, VDER does not require any performance obligations; consequently, it should be relatively straightforward to prevent double payments for wholesale energy and capacity, while leaving the rest of the value stack in place for other services.
- Determine the detailed functionalities, and corresponding operational and management systems, needed to implement the market-coupling framework.

Path Forward

- Joint Utilities to establish the working group by February 1, 2019 with an initial report to the Commission due by July 1, 2019.

4.8 Accountability

Staff recommends that the Commission order establish accountability over those responsible for achieving the 2025 and 2030 storage targets. This especially includes NYSERDA, the investor owned utilities, and LIPA/PSEG. In order to facilitate this review, Staff recommends that DPS and NYSERDA Staff provide the Commission annually with a State of Storage report that presents progress toward achieving the storage targets, zonal locations of installations, pipeline, solutions deployed and the ranges of use cases, as well as impediments and proposed solutions to these impediments that may slow deployment. This shall also include corrective paths for reallocating bridge incentive funds and other measures as needed to ensure that these targets are reached.

Path Forward

- Staff recommends that the Commission's energy storage order include specific requirements that must be included in this annual report, along with any other mechanisms that will add accountability.

5 Path Forward

Energy storage is at the forefront of the dynamic changes occurring in New York's energy sector, and the State is on the cusp of unleashing its benefits. The Roadmap recommendations seek to facilitate the most valuable, affordable and effective means of realizing those benefits. The many policy, regulatory and programmatic actions described throughout the Roadmap are intended to accelerate the market learning curve, drive down costs, and speed the deployment of the highest-value storage applications. Implementing these recommendations will deliver tangible economic, job creation, and public health benefits to New Yorkers while building the necessary framework to foster a self-sustaining market to achieve the Governor's 2025 storage target on a path to meeting the 2030 storage target to be established by the Commission later this year.

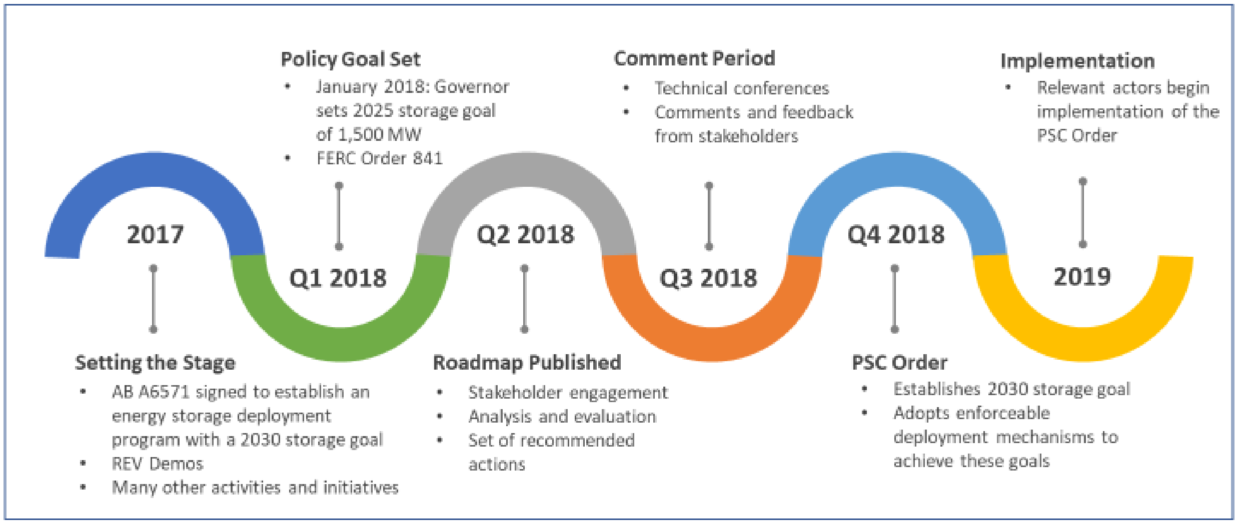
Stakeholder Input

The development of the Roadmap actions was informed by numerous stakeholder conversations during the past year including during development of the Acelerex energy storage study. Stakeholder feedback was solicited during the Roadmap development through individual and group meetings with storage developers, renewable energy developers, system integrators, power producers, trade groups, the Joint Utilities, LIPA, NYPA, and the NYISO. Public informational webinars were also held to present preliminary study findings and solicit input on Roadmap topics. Finally, Staff engaged Energy & Environmental Economics (E3), the Center for Renewables Integration, and the Climate Policy Initiative to assist with project economic modeling, examining actions considered in other jurisdictions, and developing these recommendations.

Release of this Roadmap represents the beginning of the formal public input phase. DPS and NYSERDA Staff will be holding several technical conferences during the stakeholder input phase of this Roadmap. Interested parties should follow Case 18-E-0130 In the Matter of Energy Storage Deployment Program in the Department's Document and Matter Management System, which may be accessed at http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=55960 and/or should sign up to receive updates at https://www.nyserda.ny.gov/All-Programs/Programs/Energy-Storage-Program/Energy-Storage-Email-List. Input from stakeholders may be provided on any aspect(s) included in this Roadmap and any other potential actions that stakeholders feel should also be considered. The Commission will consider these items as it evaluates a 2030 storage target and deployment of mechanisms and programs that will allow the State to meet the 2025 target on a pathway to meeting the 2030 target that will be established pursuant to PSL §74.[77]

[77] At Staff's request, the matter was opened to comply with the directive to commence a proceeding within 90 days of the new PSL §74 effective date. Proposed legislation to amend the existing storage law (Laws of 2017, A6571) was introduced in early January 2018, which would remove the 90-day clock and direct the Commission to establish by December 31, 2018, an energy storage target for 2030 and a deployment policy to support that target.

Figure 14. High-Level Timeline of New York State Anticipated Storage-Related Milestones



DPS and NYSERDA Staff wish to thank the large number of stakeholders who engaged during the formative stages of the Acelerex energy storage study and the development of this Roadmap. All stakeholders including developers, customers and interested parties are strongly encouraged to participate in the formalization of this Roadmap by offering input and additional recommendations and participating in the technical conferences.

New York State Energy Storage Roadmap

and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations:

APPENDIX

Contents

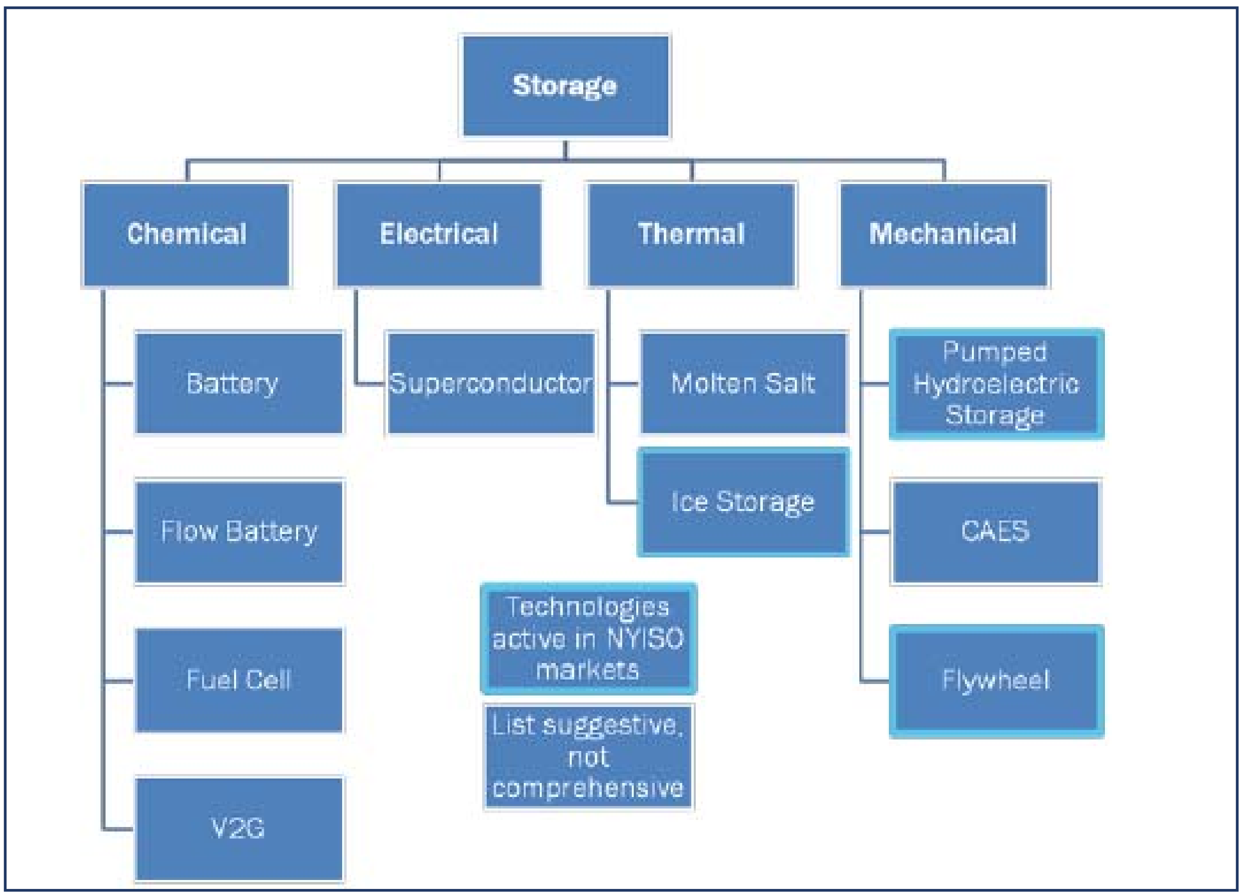
A. Background

A.1 Types of Energy Storage

Energy storage is made possible by a range of technologies with different capabilities, costs, and sizes. Energy storage technologies can be organized into the following four categories:

- **Electrochemical** technologies, including both solid state batteries (e.g., lead acid, lithium ion, sodium sulfur, and sodium metal halide) and rechargeable flow batteries, as well as ultracapacitors and hydrogen and fuel cells;
- **Mechanical** technologies such as pumped hydro storage, compressed air energy storage (CAES), and flywheel storage;
- **Electrical** technologies such as Superconducting Magnetic Energy Storage (SMES), which stores energy in the magnetic field created by current flowing through a superconducting coil;
- **Thermal** technologies, including ice storage and molten salt storage.

Figure 1. Description of Storage Technologies[1]



[1] https://home.nyiso.com/blog/nyiso-library-media/the-state-of-storage-in-nys-wholesale-electricity-markets/

A range of factors influences the use and application of energy storage technologies. These include electrical performance, both in terms of a technology's energy and power density, as well as its size and weight, capital costs, efficiency, cycle life, and operating costs. Time – specifically the time associated with extracting energy from a storage source – is a dimension across which technologies differ greatly, with shorter-duration technologies providing value in ancillary services applications, for example, and longer-duration technologies helping the bulk system to time-shift renewable energy generation and manage peak demand.

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 implemented.

A.2 Current Routes to Market for Energy Storage

Currently, there are limited routes to retail and wholesale markets for energy storage systems. In addition, current rules preclude energy storage systems from providing multiple services to the existing market segments: customer-sited, distribution system, and bulk system. There are also existing market rules that would limit the ability for storage systems to provide certain services. NYSERDA contracted NY-BEST to develop a fact sheet and guide[2] that summarizes existing services and market rules currently available for energy storage systems installed in New York State. These resources will continue to be updated as the recommendations included in this Roadmap are considered, adopted and implemented.

[2] https://www.ny-best.org/resource/energy-storage-soft-costs-resources

B Use Case Analytical Methodology and Overall Results

Above all, the Roadmap's recommended actions were informed and guided by analysis. This analysis examined project economics for individual use cases, which involved modeling potential value streams for each use case in the context of current and forecasted installed costs for storage. The recommendations that emerged from this analysis are those that are best suited to scale storage deployments in New York, with an explicit focus on the near (2019-21) and medium term (2022-25).

Developing the Roadmap involved numerous distinct analytical tasks and workstreams. Modeling helped identify both the recommendations and outcomes needed for storage deployments to occur, while accounting for barriers that could realistically be remedied. The remaining tasks involved market sizing estimates of storage applications and use cases (if applicable and informative), and exploring the financing, operations, and revenue for illustrative use cases to provide greater insight into the impact of Roadmap actions.

B.1 General Framework

As summarized in Section 3 of the Roadmap, the analytical framework of this report is structured around examining the costs of energy storage and quantifying the potential future value streams[3] for specific use cases and operations, financing, and business models.

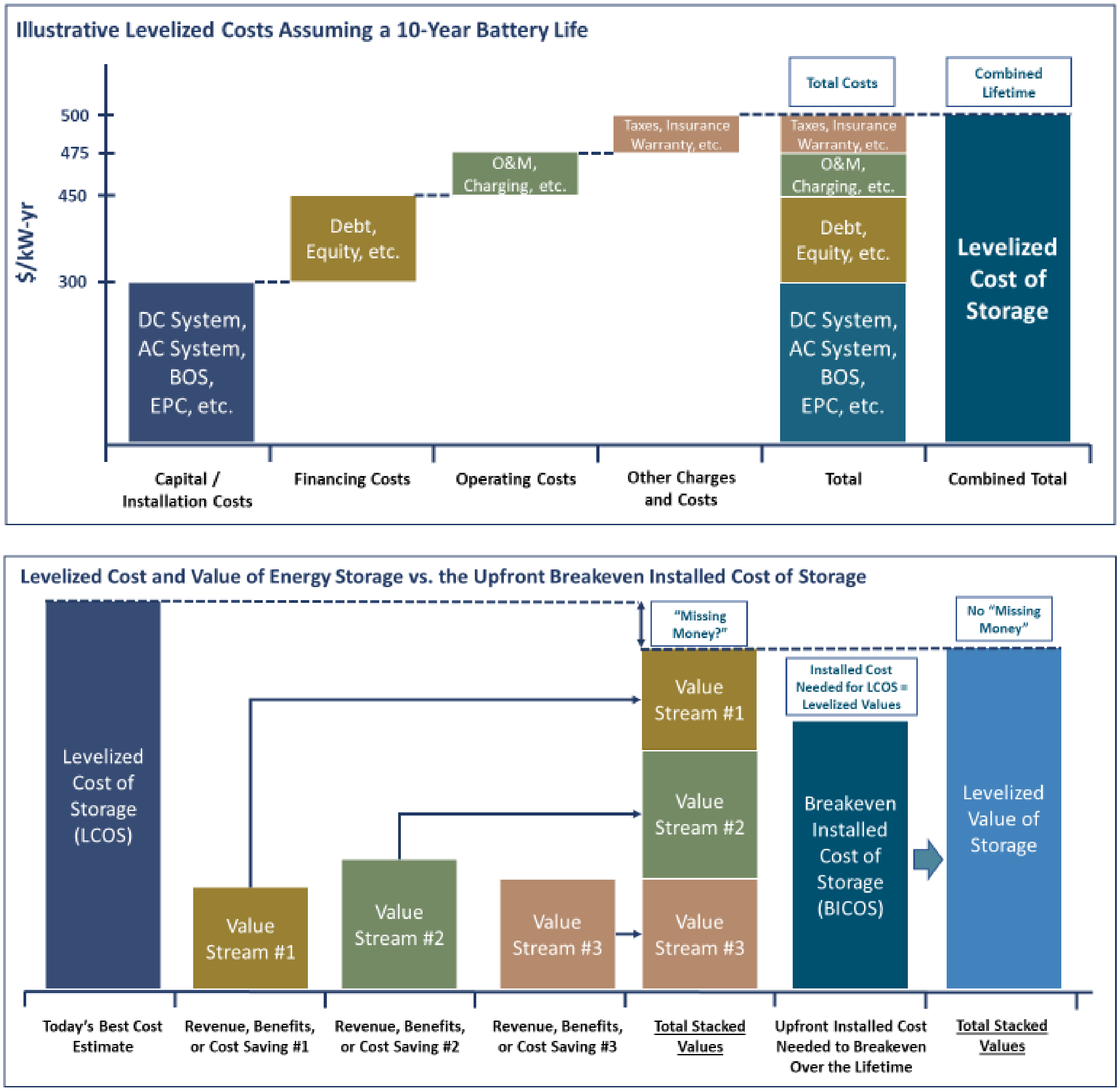
The two figures below illustrate how the cost of energy storage is built up from its underlying components, as well as how that cost compares to its value.[4] If the levelized values exceed the levelized cost of storage (LCOS), the project is assumed to be commercially viable given the underlying assumptions. If the levelized cost exceeds the levelized value, then there is "missing money": a funding gap of a certain size that renders a project uneconomic and therefore prevents commercial viability. The upfront **breakeven installed cost of storage (BICOS)** is the primary analytical metric used in this analysis. BICOS indicates what the total upfront cost of storage must be for a project to be economically feasible, defined as the project benefits or values exactly equaling all costs to install, commission, finance and provide a return on the project over its life.[5] The higher the BICOS, the better the project's economics and the closer it is to commercial viability today based on current installed cost. This metric was useful given the range of storage technologies and current costs.

[3] In this report, "value streams," "benefits," and "revenues" are all synonymous and used interchangeably.

[4] In general, all costs and values in this analysis are levelized, meaning that they are calculated on an annual basis under a single set of assumptions and then converted to annual streams over the 10-year assumed lifetime of the storage asset. Levelization, a common industry practice, enables apples-to-apples comparison of multiple generation technologies and, in this case, modeled use cases for energy storage. It can also be thought of as a long-term contract or power purchase agreement price.

[5] The BICOS metric is not a levelized number itself, but it is calculated based on a project's levelized costs and benefits in order to determine the total upfront installed cost of storage so that the levelized costs exactly equals the levelized benefits.

Figure 2. Illustrative Visualizations: Levelized Costs, Levelized Values and Breakeven Installed Cost of Energy Storage (BICOS)



Objectives

The Roadmap's analytical framework was developed with four objectives in mind:

1. Determine a representative set of use cases for examination that strikes the right balance between providing substantive, actionable information, and keeping the analysis manageable given the vast number of potential storage applications that could be modeled and analyzed.
2. Provide a clear analytical methodology and standard set of reporting metrics on costs vs. value for a selected set of storage use cases to assess their commercial viability for realistic deployment over the Roadmap's time horizon, focusing on the near and medium term (2019-25).

3. Perform in-depth analyses on a smaller set of down selected use cases to develop, inform, and test certain compelling policy, regulatory, and programmatic actions that this Roadmap recommends.
4. Determine an approach (where informative) to develop market sizing estimates for larger storage application groupings (and, where appropriate, specific use cases).

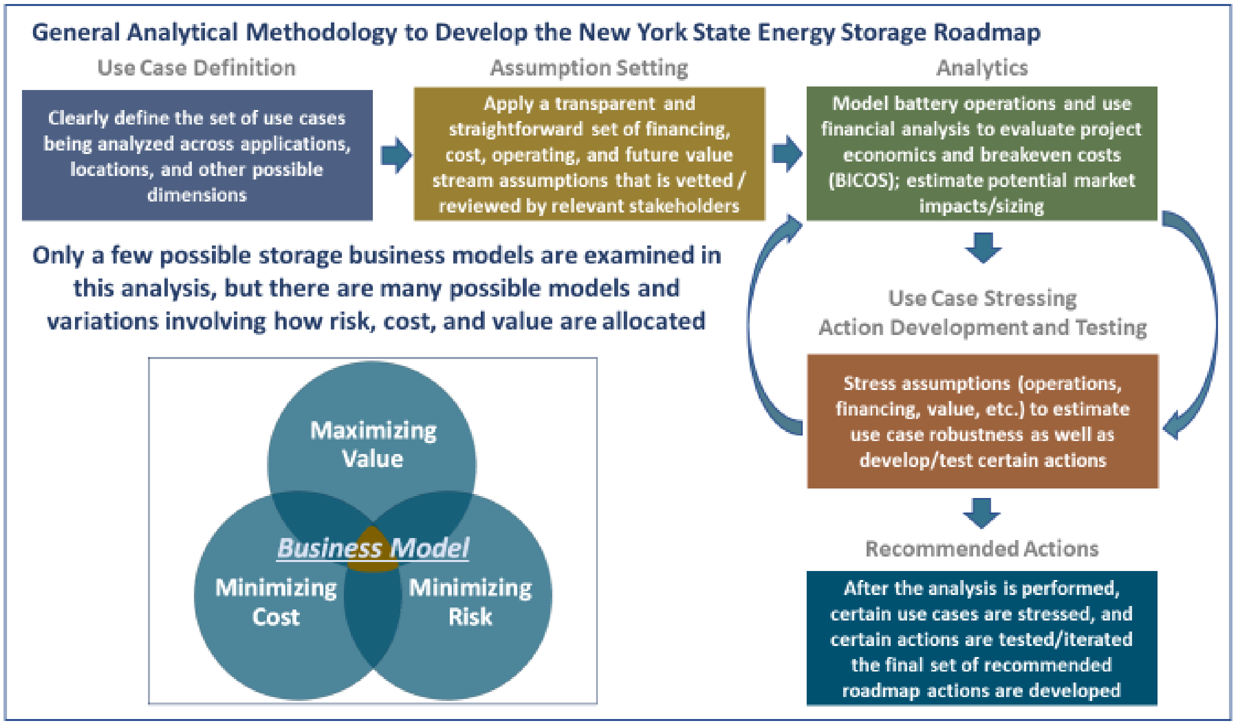
Clarifications and Caveats

Several scoping decisions were made to achieve the above objectives that require explanation:

1. **Common metrics** – e.g., payback, internal rate of return, net costs/benefits, etc. – were calculated, but because each is very sensitive to a host of underlying assumptions (e.g., about storage cost, business model, operating parameters, etc.), the Roadmap's primary metric, BICOS, is presented as a simple yet insightful way to gauge the overall economics of specific use cases. This BICOS metric allows various storage technologies to be substituted for one another. The Roadmap is technology-agnostic, and its recommended actions are meant to apply to all storage technologies and DERs.
2. **Not all potentially viable use cases or business models were examined.** This is simply due to the vast number of possible use cases and business models that could reasonably be constructed across multiple dimensions (i.e., technology, interconnection level, location, control mode, accessible value streams, ownership, financing, value sharing, etc.). The use cases analyzed were chosen to illustrate how storage deployments could occur and scale over the Roadmap's timeframe, particularly in the near and medium term. This does not preclude or limit other types of storage deployments that may occur under a variety of different business models and whose commercial viability will depend on overall industry dynamics, the developing market in New York, and project-specific circumstances.
3. **A single energy storage installed cost forecast, tailored to the New York market, was used in this analysis**. This was done to determine 2019 base case project economics for the use cases, as well as to estimate when the market might approach the levels needed for use cases to reach commercial viability.
4. **Not all possible value streams, benefits, revenues, or cost savings** – either to various market participants or to society as a whole – **were modeled or evaluated** as part of this analysis. Rather, the Roadmap focuses specifically on those value streams that could potentially be monetized in the near or medium term.
5. **Not every recommended action was tested quantitatively**. Certain actions are more qualitative in nature, while others require further study or may involve creating the enabling conditions to realize certain modeled values or reduce barriers to storage deployment.
6. **The market sizing estimate is a hypothetical, yet plausible deployment scenario**. A market sizing estimate was done to create a representation of a reasonable deployment scenario that reaches the New York State target of 1,500 MW by 2025. It is not reflective of overall market potential or representative of all possible storage use cases, nor does it describe the total addressable market.

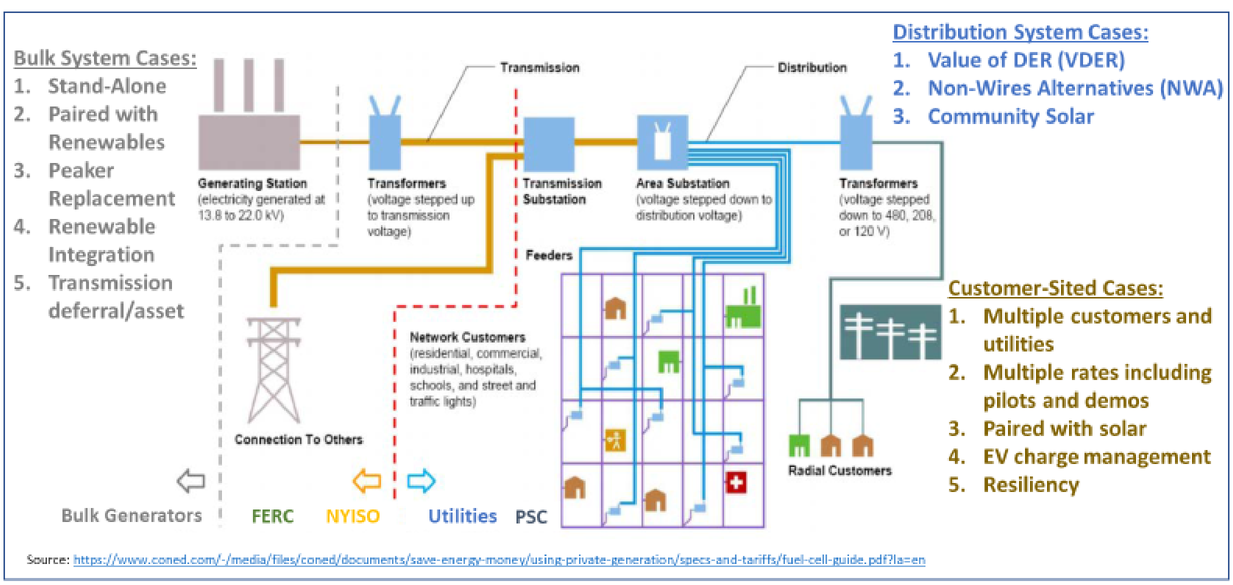
The following figure illustrates the **analytical methodology** used in the Roadmap's exploration of energy storage use cases at the customer, distribution, and bulk system levels.

Figure 3. Overview of the Roadmap's Analytical Methodology



Similarly, the following figure illustrates the general categories of use cases that were analyzed in this Roadmap. The full detailed list of use cases can be found in the associated subsections.

Figure 4. Categories of Use Cases Analyzed in this Roadmap[6]



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[6] https://www.Con Ed.com/-/media/files/Con Ed/documents/save-energy-money/using-private-generation/specs-and-tariffs/fuel-cell-guide.pdf?la=en

B.2 Use Case Approach

Within each of the three market segments of storage applications – customer-sited, distribution system, and bulk system – specific use cases were modeled[7] across several dimensions (e.g., connection level, geographic location, value streams, etc.). While it was not feasible to examine all potential business models or variations along all dimensions as part of this Roadmap development process, one or more downstate locations and at least one upstate location were analyzed to achieve geographic diversity. Conducting the analysis in this way produced three important outcomes: it provided information on the current market, project economics and values specific to each use case; it highlighted the challenges and barriers associated with certain storage uses; and it provided a benchmark to test and quantify impacts of the Roadmap's recommended actions.

The figure below details the Roadmap's four-step approach to use case modeling, the results of which inform the recommended actions set forth in this Roadmap.

Step 1 A representative set of use cases within each market segment is chosen in order to determine which specific use cases have the potential for near-term and medium-term deployment (in 2019-21 and 2022-25, respectively).

Step 2 Use cases are first analyzed by assuming perfect foresight and full achievement of modeled value streams over time. In some cases, full achievement may not be possible under current market rules/constraints, so "real world" de-rates are applied to reflect more realistic revenue achievement.

Step 3 The results from Step 2 are used as a basis for further testing where operations, financing, and achievement of value streams are "stressed" for a down selected set of specific use cases; this is then used to test specific actions, or groups of actions.

Step 4 Key takeaways and insights are presented based on the previous steps, which directly inform the Roadmap's recommended actions.

B.3 Customer-Sited Analysis

Customer-sited storage can help reduce customer electric utility bills, provide demand response (DR) and resiliency benefits during an outage, and manage other distributed energy resources (DERs) like solar PV and electric vehicles. On-site storage allows customers to reduce their peak electricity usage, which in turn lowers the demand charge[8] on a customer's electric utility bill (whether that charge is calculated on a monthly, daily, or sub-daily basis). Customers with storage can also avoid paying high electricity prices when "smart rates" increase prices during times of high electricity demand. Further, energy storage can increase customer demand response (DR) participation by shaping customer loads while lowering local distribution system peaks, thereby providing value to the utility and to other customers.

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[7] E3's RESTORE model was used to simulate the storage dispatch, operations, and economics including financing of all the use cases. https://www.ethree.com/tools/restore-energy-storage-dispatch-model/

[8] http://legacyold.Con Ed.com/customercentral/demandbilling.asp

The customer-sited use cases pair energy storage with representative commercial and residential customer load profiles to evaluate savings and revenue potential. The goal of this analysis, which examined project economics across several utilities and many different customer retail rates, was to determine which use cases were most likely to reach commercial viability. These use cases also highlight current barriers to replicable, scalable customer-sited storage projects as well as near-term responses.

B.3.1 Step 1: Use Cases Examined

The customer-sited use cases represent scenarios where energy storage is primarily operated to reduce onsite customer load and achieve retail electric bill savings. The use cases chosen for this analysis were based on input from developers, stakeholders, and utilities and were informed by storage deployments that are occurring in the market today.

Use cases were developed to quantify potential energy storage benefits for customers under existing and piloted tariffs throughout the state. Storage configurations were modeled for customers of Consolidated Edison (Con Ed), Long Island Power Authority (LIPA), and National Grid (Nat Grid). Representative load shapes based on actual NYS customers were used for eight different customer types, spanning large residential (multifamily), commercial, and industrial sites. Additional customer-sited cases – e.g., solar + storage, residential Smart Home Rates[9], workplace electric vehicle charging, and resiliency benefits – were also modeled based on stakeholder interest.

These customer types were selected because they have characteristic usage patterns, which allowed estimates of market sizing to occur. This is not intended to be an exhaustive list of customer types that will deploy storage.

The table below summarizes the load shape, utility and rate combinations that were included in the customer-sited use cases. More information on the utility tariffs can be found later in this section.

[9] https://www.Con Ed.com/en/business-partners/business-opportunities/smart-home-rate-demo

Table 1. Customer-Sited Use Cases and Rate Combinations

Customer Type	Location(s)	Con Ed Tariffs	LIPA Tariffs	Nat Grid Tariffs
1. Commercial Office (High Rise)	NYC	SC 9 Rate 2, SC 9 Rate 5 and SC 9 Rate 5 Rider Q[10]	284, 285	SC 3A, SC 3A-7
2. High Rise Multifamily Building (Common Area Load)	NYC	SC 9 Rate 1, SC 9 Rate 4 and SC 9 Rate 4 Rider Q	284, 285	SC 3A, SC 3A-7
3. High Rise Multifamily Building (Total Load)	NYC	SC 9 Rate 2, SC 9 Rate 5 and SC 9 Rate 5 Rider Q	284, 285	SC 3A, SC 3A-7
4. K-12 School	NYC, LI, Upstate	SC 9 Rate 1, SC 9 Rate 4 and SC 9 Rate 4 Rider Q	284, 285	SC 3A, SC 3A-7
5. K-12 School + PV	Westchester and LI	SC 9 Rate 1, SC 9 Rate 4		
6. K-12 School Resiliency	Westchester	SC 9 Rate 4		
7. Supermarket	NYC, LI, Upstate	SC 9 Rate 1, SC 9 Rate 4 and SC 9 Rate 4 Rider Q	284, 285	SC 3A, SC 3A-7
8. Low Rise Office	NYC, LI, Upstate	SC 9 Rate 1, SC 9 Rate 4 and SC 9 Rate 4 Rider Q	284, 285	SC 3A, SC 3A-7
9. Industrial Site	NYC, LI, Upstate	SC 9 Rate 2, SC 9 Rate 5 and SC 9 Rate 5 Rider Q	284, 285	SC 3A, SC 7
10. Wastewater Treatment Plant	NYC, LI, Upstate	SC 9 Rate 2, SC 9 Rate 5 and SC 9 Rate 5 Rider Q	284, 285	SC 3A, SC 7
11. Residential Customer	NYC	SC 2, Smart Home Rate		
12. Workplace EV Charging Load	NYC	SC 9 Rate 1, SC 9 Rate 4		

Value Streams

Broadly speaking, customers installing energy storage currently have access to two value streams. The first is **bill savings** on energy and demand charges. Storage can accomplish this in two ways: by lowering peaks in electric consumption, thereby reducing the demand charge ($/kW) component of the electric bill; and by charging or storing energy when retail energy prices are low and getting paid for discharging when prices are highest (i.e., energy arbitrage). The second value stream is **revenue from demand response programs.**[11] This analysis modeled customer participation in both utility (Commercial System Relief Program, or CSRP[12]) and wholesale (NYISO Special Case Resource, or SCR) market programs.[13] In paired solar + storage customer-sited use cases, benefits include energy and demand bill savings plus value stack compensation of net system exports.

[10] Con Ed SC-9 Rate 4 and 5 Rider Q's were modeled under Option B, Locational Variant Daily As-used Demand Pricing for customer not in a DLRP Tier 2 network. The CSRP network of 2-6pm was chosen for consistency with DR programs. https://www.Con Ed.com/_external/cerates/documents/elecPSC10/GR24.pdf

[11] Energy storage can also provide valuable back-up services to the host customer in case of a system outage or disturbance. Customers with significant costs associated with power interruptions (e.g., hospitals) may find this attractive, and some are already installing storage back-up systems. These benefits were not quantified.

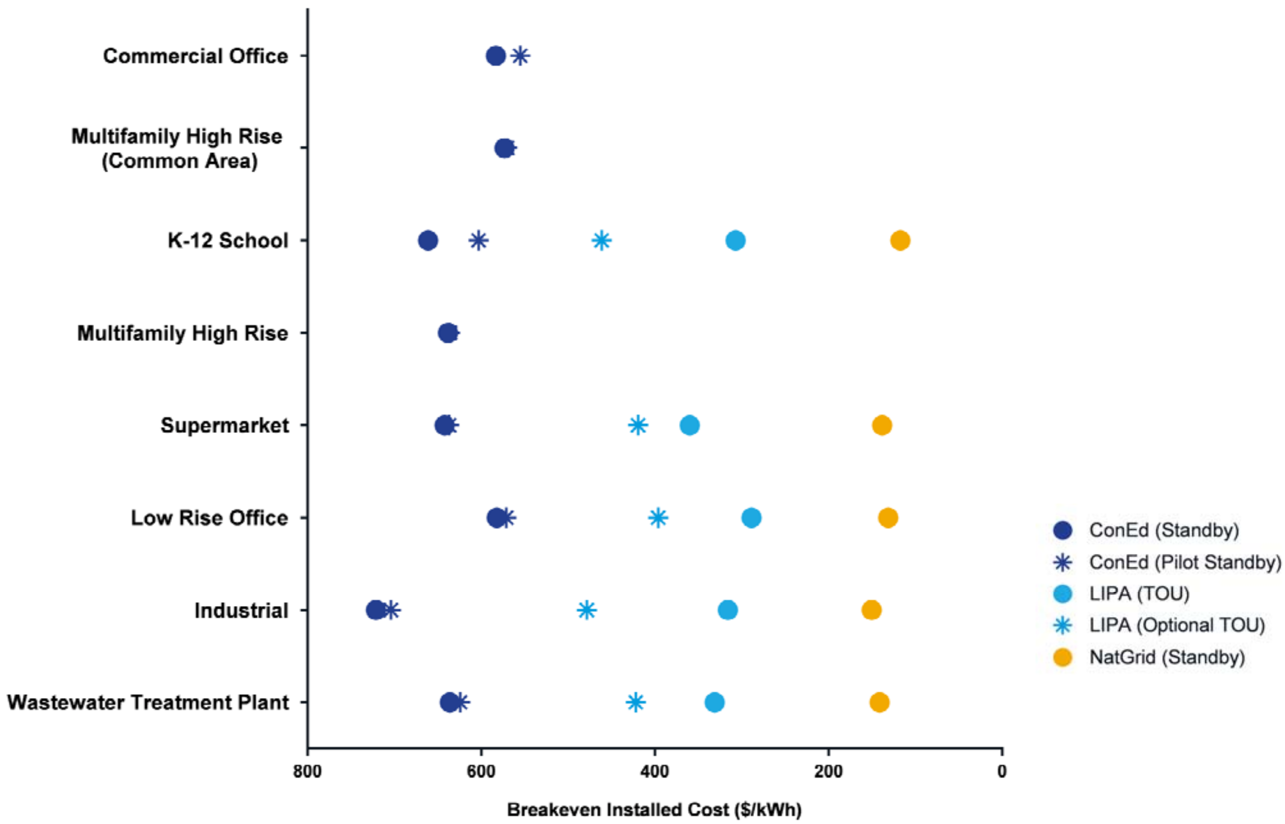
[12] https://www.Con Ed.com/en/save-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-commercial-industrial-buildings-customers/smart-usage-rewards. DR programs usually include a "reservation payment" for being available to provide the DR service and a "performance payment" which is payment for actually providing the DR service.

[13] See Appendix B.3 and B.4 for more information about demand response assumptions.

B.3.2 Step 2: Initial Results

The initial modeling was performed across all customers and rate classes shown in Table 2, above. Energy storage operations were optimized to achieve the maximum potential benefit across all available revenue streams. A downward adjustment was then applied to the total achievable revenues to reflect imperfect foresight and more realistic energy storage operations (approximately 85% of total achievable revenue potential). These adjusted revenue streams were then used to calculate BICOS values specific to each use case.[14] The figure below shows the initial results for the customer-sited use cases.

Figure 5. BICOS of Customer-Sited Use Cases Paired with Load[15]



The BICOS analysis illustrates that certain use cases currently have more promising project economics than others. In some scenarios, customer-sited installation of energy storage may be several years away from being cost-effective (absent implementation of the actions recommended in this Roadmap or greater-than-expected cost declines). For example, New York City customers under Con Ed's standby and pilot standby tariffs are much closer to breaking even in the near term as compared to LIPA or Nat Grid

[14] Various ownership models were considered, largely as a result of the impact on financing and revenue sharing. A third-party ownership model was assumed across all customer-sited scenarios. A range of financing scenarios was used to evaluate the project economics under varying degrees of revenue certainty and risk. For more information about financing assumptions, see Appendix B.4

[15] Storage sized at 10% of the customer's peak load for 4-hour duration. Compensation is bill savings & Demand Response revenues (CSRP and SCR DR programs). Base Case Financing is 3rd party financed, 60% equity @ 12% and 40% debt @ 7% for a 9.3% WACC & discount rate. DR revenue considered for 10 years. 15% De-rate applied to revenues to reflect real world scenario without perfect foresight.

customers; this is due to Con Ed customers' higher demand and energy charges, leading to higher potential bill savings and DR program compensation which yields better project economics. More detailed results can be found later in this section.

As shown below, the Roadmap examined several other use cases, including BTM solar + storage, electric vehicle (EV) management, resiliency benefits, and Con Ed's residential Smart Home Pilot Rate. The EV and resiliency cases are primarily illustrative and are not exhaustive of the diverse set of configurations within these use case categories.

Results for Paired Solar + Storage and Residential Use Case Modeling[16]

Paired Solar + Storage Located Behind the Meter at a K-12 School

The economics of pairing storage with a planned or existing PV system are attractive because developers can take advantage of the Federal Investment Tax Credit (ITC): if energy storage meets a minimum charging threshold from the on-site PV system, storage costs become eligible for the ITC. This reduces the capital costs required to install energy storage by up to 30%, enables shaping of PV output to take advantage of high grid-need hours, and reduces potential solar curtailment. Paired solar and storage use cases were modeled with the K-12 School load shape in Westchester and on Long Island under the corresponding Con Ed and LIPA tariffs. A representative PV generation shape was used for a fixed roof mount SW-facing system. While the PV system adds significant costs to the project, the addition of the ITC and the ability to shape system output increases benefits and results in a higher BICOS of the paired system than for stand-alone storage. The BICOS of the paired system was found to be around $200 to $450/kWh higher than with storage alone. Additional BTM PV + storage modeling should be performed with different customer types and using PV generation profiles from a range of configurations and geographic locations

Table 2: BICOS of Paired and Unpaired BTM Use Cases

K12 School	Storage in Paired PV System	Unpaired Storage
Con Ed (Westchester)	$870/kWh	$445/kWh
LIPA	$555/kWh	$95/kWh
NatGrid	$245/kWh	$30/kWh

The results of the paired system assume that net storage exports are compensated at ICAP Alternative 3 under the Value of Distributed Energy Resources Value (VDER) Value Stack tariff. Alternative 2 was also modeled and resulted in a 30 percent lower BICOS than Alternative 3 for the Con Ed Use Case. The results are much more similar for the two ICAP alternatives in the LIPA and NatGrid use cases. In the case of Con Ed, the bill charges that would be incurred outweigh the potential benefits of exporting during the more dispersed Alternative 2 ICAP hours.

Con Ed's Smart Home Demonstration Rate

In addition to the larger customer-sited use cases, a New York City residential profile was modeled to explore the benefit of storage under Con Ed's time of use (TOU) optional rate compared to Con Ed's Smart Home Rate (SHR) demonstration rate. Under the TOU rate, storage performs energy arbitrage by charging during off-peak periods and discharging during peak, high-price periods. However, greater storage benefits are achieved under the SHR, which has avoidable demand charges. The BICOS of storage under the SHR is approximately $450/kWh, compared to around $315/kWh under the TOU rate.

[16] Paired use case sited at K-12 School. Solar is sized at 350 kW and storage is sized at 90 kW, 4-hour duration. Solar profile representative of fixed (roof mount), south facing system. Minimum charging threshold is defined by storage size use case. All paired use cases are modeled as charging 100% by solar system for this analysis. For the SHR use case storage is sized at 25% of the residential customer's peak (0.70 kW), 4-hour duration (2.8 kWh).

Results for Resiliency Benefit and EV + Storage Use Case Modeling[17]

Resiliency Benefit from Paired PV + Storage

Behind-the-meter storage can also provide back-up services to the host customer if there is a system outage or disturbance. The resiliency benefit was explored at a high level for illustrative purposes by examining a solar + storage system at a K-12 School in New York City, which could theoretically provide refuge to the public during an outage. High value of lost load (VoLL) makes these cases economic, but it is difficult to monetize these values or quantify the value of providing power for different durations such as with a 4-hour duration energy storage system in an outage situation. At an assumed VoLL benefit of $1000/kWh , storage could provide around $500/kW of annual resiliency benefits.

EV Charging

A workplace EV charging profile was also modeled with storage to determine potential bill savings. The EV charging profile was assumed to be unmanaged (i.e., without "smart charging"). The BICOS of storage paired with an unmanaged EV workplace charging load under Con Ed's standby SC9 Rate 4 was found to be approximately $350/kWh. The benefits of pairing storage with EV charging loads should be further explored and compared to the benefits of storage under a "smart charging" scenario. Presumably, greater benefits could be achieved if the EV load is being managed to avoid higher bills.

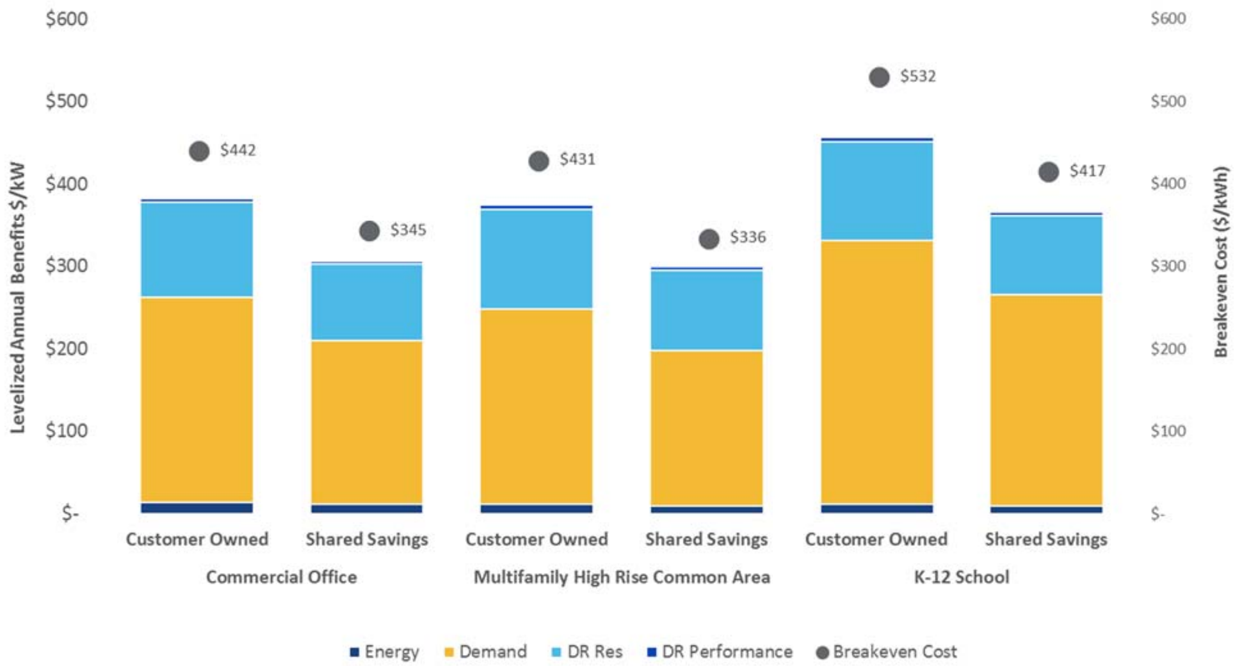
B.3.3 Step 3: Stress Testing and Action Testing

Detailed stress testing was performed using Con Ed's standby and pilot (Rider Q) standby rates for three customer types: **Commercial Office**, **High Rise Common Area**, and **K-12 School**. Selection of these customers was based on the results of the analysis in Step 2 and the potential market impacts.

A range of energy storage sizes was tested to explore the dynamic between the existing Con Ed standby tariffs (which have a longer peak demand charge window) and the Rider Q tariff (which has a narrower, 4-hour peak that better aligns with system needs). Specific value streams, such as DR program revenues, were isolated and stressed to determine the overall impact on project economics. Higher-cost financing scenarios were also applied to reflect the risk and variability of value streams and quantify how this uncertainty impacts the project economics. Stress testing was done for two business models: 1) customer-owned storage and 2) shared savings, where a third party owns the storage and shares value with the customer via an agreement or lease.[18] The results for the stress-tested scenarios are shown in the figure below.[19]

[17] Use case modeled paired solar and storage sited at K12 School and assigns a value of lost load of $1000/kWh. Solar is sized at 350 kW and storage is sized at 90 kW, 4-hour duration. For EV cases, 5 travel behavior profiles were randomly generated from statistical distributions derived from National Household Travel Survey data https://nhts.ornl.gov/. EV parameters were based on the 2018 Chevrolet Bolt. EVs are assumed to be plugged in during business hours. No constraints were applied to the state of charge of the EV.
[18] Under the shared savings model, 20% of the project revenue is shared with the customer. A complete description of stress testing and finance assumption approach can be found in Appendix B.4 and Appendix E .
[19] Con Ed's Demand Response program CSRP compensation was assumed to only be available for 3 years, and higher cost financing is assumed.

Figure 6. Benefits Breakdown for Three Stress-Tested Customer-Sited Use Cases[20]



Stress testing the use cases provided a lower bound to the potential achievable revenue in customer configurations. The results illustrate the need for increased revenue certainty and lower upfront costs for storage to become attractive. Actions such as locking in certain value streams to increase revenue certainty and lower financing risk and implementing a market acceleration incentive can lead to projects becoming economic.

After completing the stress testing, incremental changes to use cases were modeled to measure the impact of specific actions. As shown in the figure above, DR program revenue can be a significant contributor to overall project benefits. One action tested was to model the DR compensation structure for storage projects as more certain[21] for the assumed project lifetime of 10 years. This results in around 25 percent higher BICOS from the stress-tested scenarios for both the customer-owned and shared savings models. The K-12 School has a higher portion of benefits coming from demand bill savings than DR revenues and was therefore less affected by the 10-year assumed certainty in DR revenues than were the Office or Multifamily customers.

With increased revenue certainty, the financing of customer-sited projects should also improve to reflect reduced project risk. Lower-cost financing was therefore assumed as an incremental step towards achieving commercial viability, with different assumptions of improved financing being applied to the customer-owned and shared savings models.[22] Under the customer-owned model, a nearly 20 percent higher BICOS resulted from improved financing alone. The shared savings cases saw a lower increase of

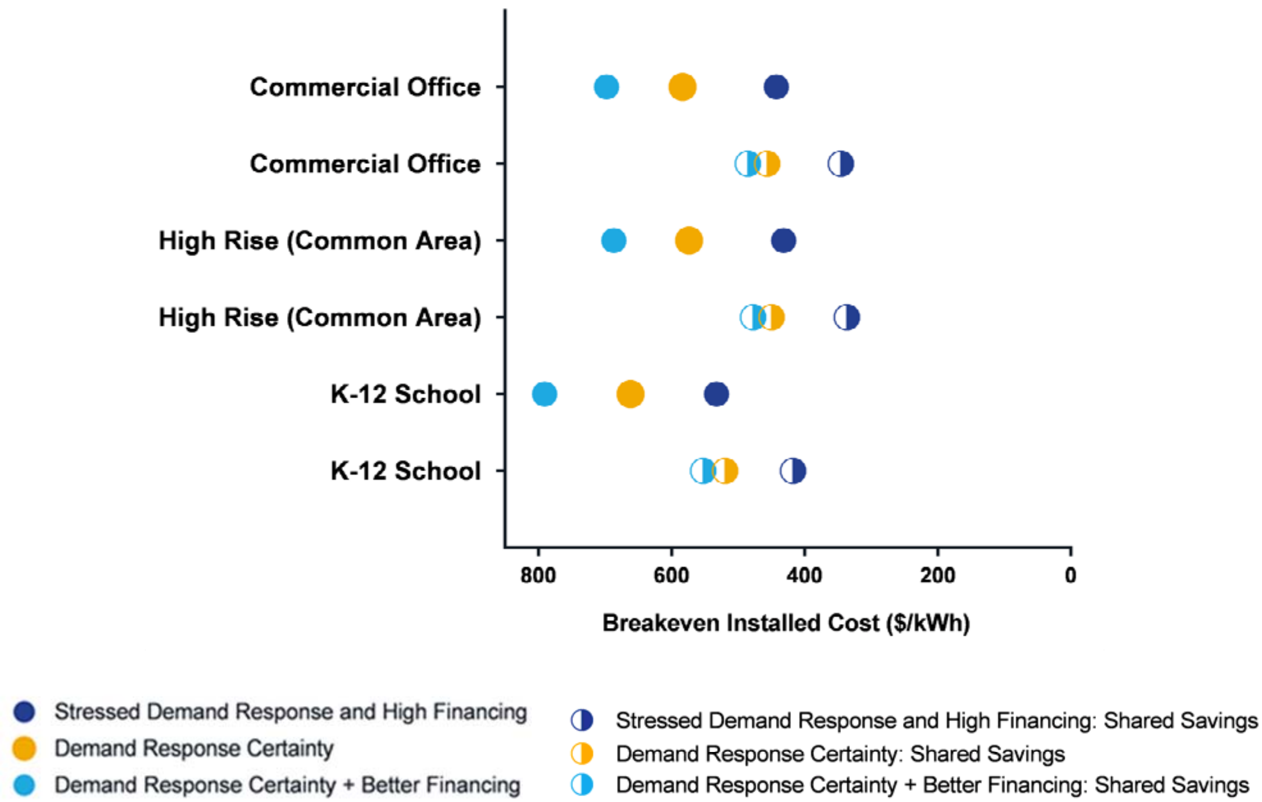
[20] Stress financing is third party financed at 100% equity with 12% WACC. For shared savings model, 20% of revenue is assumed to go to the customer. A 15% de-rate is applied to all revenues to reflect real world scenario without perfect foresight. CSRP participation assumed for 3 years, SCR participation modeled for project lifetime (10 years).

[21] This certainty could be either from a direct lock of the DR payment levels or from a more certain and stable multi-year payment for the 10-year project lifetime.

[22]See Appendix B.4 and Appendix E for more details on financing assumptions.

about 6 percent. The figure below shows the BICOS assuming 3- and 10-year CSRP program revenue certainty and lower-cost financing. Overall, economics improve by around 50-60 percent under the customer-owned model and 30-40 percent under the shared savings model when compared to the stressed case results. However, installed storage costs are still above what is required for these projects to break even.

Figure 7. Results: Stress Testing and Action Testing for Three Customer-Sited Use Cases[23]



Summary of Stress Testing and Action Testing

For the customers and rates analyzed, the economics hinge on the **ability to access multiple value streams** (i.e., bill savings and demand response). The most significant value potential for customer-sited storage is demand charge savings, and thus customers on rates with higher demand ($/kW) charges will see better project economics. Energy bill savings from arbitrage (charging off peak and discharging during peak electric demand) are nominal when high demand charges are present. While total bill savings is specific to a customer's load shape, the three down selected customers achieve overall bill savings in the range of 5-20 percent. DR program revenues are also a significant driver of these cases' overall project economics, with reservation payments ($/kW) dominating overall DR revenues.[24] Stress testing demonstrates that project economics are sensitive to revenue certainty and financing assumptions.

[23] Demand Response Certainty represents CSRP participation for project lifetime (10 years). Improved financing for the customer-owned model assumed 100% debt. In the shared-savings, model, and 50% debt equity split is assumed. See Appendix B.4 and Appendix for more details on stress and action testing and financing assumptions.

[24] Because DR program calls, and therefore revenues, can vary significantly on an annual basis, DR revenues were stress tested to explore the sensitivity of project economics to this uncertainty.

B.3.4 Step 4: Key Takeaways

The customer-sited key takeaways, developed based on the results presented above, are summarized in Section 3.1 of the Roadmap.

B.4 Detailed Customer-Sited Results and Assumptions

The following table details the customer-sited benefits and BICOS across each customer type and utility.

Table 3. Breakeven Installed Costs ($/kWh) and Benefits ($/kW-yr) Across All Customer-Sited Use Cases[25]

Con Ed Customer & Rate	Commercial Office SC-9 Rate V	Commercial Office SC-9 Rate V Rider Q	Multifamily Common Area SC-9 Rate IV	Multifamily Common Area SC-9 Rate IV Rider Q	K-12 School SC-9 Rate IV	K-12 School SC-9 Rate IV Rider Q
Total Modeled Benefits ($/kW-yr)	**$434**	**$415**	**$428**	**$426**	**$490**	**$450**
Energy Bill Savings ($/kW-yr)	$13	$13	$11	$11	-$9	-$9
Demand Bill Savings ($/kW-yr)	$251	$232	$238	$235	$322	$282
Demand Response Payment ($/kW-yr)	$170	$170	$179	$179	$178	$178
Breakeven Installed Cost ($/kWh)	**$583**	**$555**	**$573**	**$570**	**$661**	**$603**
Con Ed Customer & Rate	**Multifamily High Rise SC-9 Rate IV**	**Multifamily High Rise SC-9 Rate IV Rider Q**	**Supermarket Standby SC-9 Rate IV**	**Supermarket SC-9 Rate IV Rider Q**	**Low Rise Office Standby SC-9 Rate IV**	**Low Rise Office SC-9 Rate IV Rider Q**
Total Modeled Benefits ($/kW-yr)	**$472**	**$471**	**$476**	**$472**	**$436**	**$428**
Energy Bill Savings ($/kW-yr)	$11	$11	$16	$16	$13	$13
Demand Bill Savings ($/kW-yr)	$282	$281	$281	$277	$244	$237
Demand Response Payment ($/kW-yr)	$179	$179	$179	$179	$178	$178
BICOS ($/kWh)	**$638**	**$636**	**$642**	**$637**	**$582**	**$571**

[25] Results are shown for customer-sited use cases with 10 years of Demand Response Revenue under the Base Financing Assumptions.

Con Ed Customer & Rate	Industrial SC-9 Rate V	Industrial SC-9 Rate V Rider Q	WWTP Standby SC-9 Rate V	WWTP Standby SC-9 Rate V Rider Q
Total Modeled Benefits ($/kW-yr)	**$530**	**$518**	**$470**	**$462**
Energy Bill Savings ($/kW-yr)	$9	$9	$3	$4
Demand Bill Savings ($/kW-yr)	$342	$330	$290	$281
Demand Response Payment ($/kW-yr)	$179	$179	$177	$177
BICOS ($/kWh)	**$721**	**$704**	**$636**	**$624**

LIPA Customer & Rate	K-12 School 284	K-12 School 285	Supermarket 284	Supermarket 285	Low Rise Office 284	Low Rise Office 285
Total Modeled Benefits ($/kW-yr)	**$353**	**$263**	**$323**	**$251**	**$362**	**$281**
Energy Bill Savings ($/kW-yr)	$61	$57	$61	$57	$61	$57
Demand Bill Savings ($/kW-yr)	$236	$148	$204	$136	$244	$165
Demand Response Payment ($/kW-yr)	$56	$57	$58	$58	$58	$58
BICOS ($/kWh)	**$461**	**$331**	**$419**	**$316**	**$478**	**$360**

LIPA Customer & Rate	Industrial 284	Industrial 285	WWTP 284	WWTP 285
Total Modeled Benefits ($/kW-yr)	**$307**	**$233**	**$323**	**$244**
Energy Bill Savings ($/kW-yr)	$61	$57	$60	$57
Demand Bill Savings ($/kW-yr)	$188	$118	$205	$130
Demand Response Payment ($/kW-yr)	$58	$58	$58	$58
BICOS ($/kWh)	**$396**	**$289**	**$422**	**$307**

National Grid Customer & Rate	K-12 School Standby SC-7	Supermarket Standby SC-7	Low Rise Office Standby SC-7	Industrial Standby SC-7	WWTP Standby SC-7
Total Modeled Benefits ($/kW-yr)	**$131**	**$134**	**$123**	**$149**	**$134**
Energy Bill Savings ($/kW-yr)	($5)	$10	$9	$11	$8
Demand Bill Savings ($/kW-yr)	$102	$90	$80	$104	$93
Demand Response Payment ($/kW-yr)	$34	$34	$34	$34	$34
BICOS ($/kWh)	**$141**	**$145**	**$129**	**$168**	**$147**

B.4.1 Customer-Sited Use Case Financing Assumptions and Sensitivities

For behind-the-meter use cases, there are a wide variety of business models. For this analysis, two key types of business models were analyzed:

1. **Customer ownership** of the storage asset, where the customer provides the equity investment in the project and the benefits they receive are part of their return on equity.
2. **Lease or shared savings**, where we assume the customer receives 20 percent of benefits from the storage asset.

For each of these options, we developed several financing scenarios to reflect the range of potential financing costs.

1. For the base case, we assumed a capital structure with 40 percent debt with an interest rate of 7 percent and 60 percent equity with an after-tax hurdle rate of 12 percent.
2. As a stress case, we assumed an all-equity structure with an after-tax hurdle rate of 12 percent.
3. As a post-action case for customer ownership, we assumed the upfront cost of storage was 100 percent covered by a debt instrument with a cost of capital of 6 percent. This is indicative of what may be possible through property assessed clean energy (PACE) financing.
4. As a post-action case for third-party ownership, we assume a modest improvement in leverage and cost of debt, to 50 percent debt at an interest rate of 6 percent, reflecting somewhat less risky demand response revenues.

Counterparties in Behind-the-Meter Cases

In the case of third-party ownership, the bulk of project revenues is delivered from the customer to the asset owner in the form of a lease or shared savings payment. This exposes the asset owner to counterparty risk associated with those customers.

There is wide variation among different types of customers:

- In the case of K-12 schools or public multifamily housing, counterparties would be public entities with a long operating history and bankable credit quality.
- For office buildings, supermarkets, and private multifamily housing, customers may be building owners, operators, or in some cases tenants. In these cases, credit quality and operating history may be much more variable.

Customer type may also affect the amount that underlying load profiles might change. Public buildings and commercial customers with long-term leases or building ownership may be less likely to change locations or operations substantially over time, while some commercial customers may have a higher chance of moving or changing operations in a way that impacts the value of storage.

The table below summarizes the financing scenarios used across the customer-sited use cases. A detailed description and explanation of these assumptions can be found in Appendix B.4.

Table 4. Customer-Sited Financing Scenarios

	Customer Owned				**Shared Savings**			
	Real World	**Stressed**	**Post-Action:** **DR Action**	**Post-Action:** **DR + Financing Actions**	**Real World =**	**Stressed**	**Post-Action:** **DR Action**	**Post-Action:** **DR + Financing Actions**
Percent of maximum achievable revenue	85% 3-year CSRP participation	85% 3-year CSRP participation	85% CSRP & SCR fixed/locked for 10-years	85% CSRP & SCR fixed/locked for 10-years	68% 3-year CSRP participation	68% 3-year CSRP participation	68% CSRP & SCR fixed/locked for 10-years	68% CSRP & SCR fixed/locked for 10-years
Financing	60% Equity @ 12% and 40% Debt @ 7% 9.3% WACC	100% Equity 12% WACC	60% Equity @ 12% and 40% Debt @ 7% 9.3% WACC	100% Debt @ 6% 4.4% WACC	60% Equity @ 12% and 40% Debt @ 7% 9.3% WACC	100% Equity 12% WACC	60% Equity @ 12% and 40% Debt @ 7% 9.3% WACC	50% Equity @ 12% and 50% Debt @ 6% 8.2% WACC

B.4.2 Utility Rates Modeled

Commercial time-of-use and standby tariffs were modeled for three utilities: Con Ed, LIPA and NatGrid .[26] A standby rate is a special tariff charged to large commercial and industrial customers who produce some, but not all, of their own electricity and remain connected to the grid. Standby rates allow utilities to maintain appropriate levels of T&D capacity in case customer-sited generators (e.g., solar or CHP) break down and customers need to draw energy from the grid. Whereas standby rates rely on one or more daily peaks to set the daily charge, standard demand charges utilize a monthly peak to set the value for the entire month

Commodity and delivery charges were modeled across all rates, including all volumetric ($/kWh) and demand ($/kW) charges. It was assumed that all customers had real-time commodity pricing (MHP) for the energy commodity component of their bills. Individual demand delivery charges were modeled

[26] For Con Ed and National Grid, standby rates were modeled in storage use cases and non-standby rates were used to calculate a customer's bill before installing storage. LIPA's standby rate is designed differently, so large commercial time of use rates were modeled for LIPA customers in storage use cases.
http://www.lipower.org/pdfs/company/tariff/LIPA%20Jan%202018%20Tariff%20Final.pdf

specific to the service classification (SC).[27] For example, Con Ed's standby rates include both contract demand delivery charges, based on the maximum potential demand, and daily-as-used charges, which are calculated based on the maximum daily demand during the time period for which the charge applies. Congestion Assessment and Resource Integration Study (CARIS) forecasts were used to generate annual LBMPS for MHP energy charges.[28] These annual $/MWh values were converted into hourly $/kWh values using E3's in-house hourly shaping scalars, which are based on historical price shapes.

B.4.3 Demand Response Assumptions

Participation in both utility and wholesale (NYISO) market programs was modeled. The Commercial System Relief Program (CSRP) utility program, which aims to reduce system demand, was modeled across the three selected utilities (see below). Customers enrolled in CSRP are required to reduce their demand during contracted hours, which are announced at least 21 hours prior to the event. The contracted hours (or "call windows") are four-hour periods that align with network-level peak demand. For simplicity, one call window was assumed across all customers from 2-6 p.m. Historical call hour data was used to develop a representative year.[29] The NYISO Special Case Resource (SCR)[30] program was also modeled as a value stream. Compensation is linked to a customer's baseline demand during similar hours and on similar days prior to the actual call. Under current program rules, if a customer installs a battery, their baseline demand would be altered and therefore compensation from the DR program would be affected. Baseline degradation was not modeled for the purposes of calculating achievable DR revenue to customers. Voluntary program participation was not included as an additional revenue stream. The specific programs and compensation assumptions are shown in the table below[31]:

Table 5. Demand Response Program Assumptions

DR Program	Reservation Payment	Performance Payment	Number of Calls Assumed	Hours per Call
Utility Programs				
Con Ed – CSRP	$18/kW/Month	$1/kWh	4	4
PSEG LI– CSRP	$5/kW/ Month	$0.25/kWh	4	4
National Grid – CSRP	$2.75/kW/ Month	$0.17/kWh	4	4
NYISO Programs				
NYISO SCR	Location-specific ICAP	Zonal LBMP	1	5

In the customer stress testing, CSRP program participation was limited to 3 years. Extending participation from 3 to 10 years results in a 10-15 percent higher BICOS. Participation in the NYISO SCR program was assumed for 10 years across all customer use cases.

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[27] DPS Effective Electric Tariff Documents, https://www2.dps.ny.gov/ETS/search/searchShortcutEffective.cfm?serviceType=ELECTRIC, LIPA Tariff for Electric Service, http://www.lipower.org/papers/tariff.html

[28] 2017 Congestion Assessment and Resource Integration Study. http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_(CARIS)/CARIS_Final_Reports/2017-Report-CARIS2017-Appendix-B-J-FINAL.pdf

[29] Consolidated Edison Company of New York, Inc. Report on Program Performance and Cost Effectiveness of Demand Response Programs. December 1, 2016

[30] http://www.nyiso.com/public/markets_operations/market_data/demand_response/index.jsp

[31] https://www.ny-best.org/sites/default/files/resources/Fact%20Sheet%20Spring%20Update.pdf. https://www.ConEd.com/en/save-money/rebates-incentives-tax-credits/rebates-incentives-tax-credits-for-commercial-industrial-buildings-customers/smart-usage-rewards.

B.4.4 Customer Bill Savings

Customer bills were calculated to quantify the avoided energy and bill payments from storage installation over the project's lifetime and are shown below for three Con Ed customers: commercial office, multifamily high-rise, and K-12 School. The "Before Storage" bill includes the energy and demand charge portions of the customer's bill, calculated based on the applicable non-standby rate. The post-storage bill is then calculated based on the net customer load on the standby and standby pilot rate. While total bill savings is specific to a customer's load shape, the three down selected customers analyzed achieve overall bill savings in the range of 5-20 percent.

Table 6. Customer Bill Savings from Energy Storage[32]

	Commercial Office			Multifamily High Rise (Common Area)			K-12 School		
Storage sized at 10% of Customer's Peak Load	Before Storage	Standby + Storage	Rider Q + Storage[33]	Before Storage	Standby + Storage	Rider Q + Storage	Before Storage	Standby + Storage	Rider Q + Storage
Energy Bill	$7,832,879	$6,718,594	$6,718,419	$1,481,033	$1,016,627	$1,016,622	$428,529	$298,452	$298,411
Demand Bill	$8,115,547	$8,326,574	$8,365,931	$1,059,097	$1,274,779	$1,279,020	$411,210	$430,832	$432,682
Bill Savings (%)		**6%**	**5%**		**10%**	**10%**		**13%**	**13%**

	Commercial Office			Multifamily High Rise (Common Area)			K-12 School		
Storage sized at 20% of Customer's Peak Load	Before Storage	Standby + Storage	Rider Q + Storage	Before Storage	Standby + Storage	Rider Q + Storage	Before Storage	Standby + Storage	Rider Q + Storage
Energy Bill	$7,832,879	$6,691,299	$6,689,899	$1,481,033	$1,012,487	$1,012,437	$428,529	$299,171	$298,989
Demand Bill	$8,115,547	$7,917,438	$7,982,798	$1,059,097	$1,198,102	$1,201,882	$411,210	$395,837	$403,238
Bill Savings (%)		**8%**	**8%**		**13%**	**13%**		**17%**	**16%**

B.4.5 Residential Use Case Results: Con Ed's Smart Home Rate Pilot Demo

In addition to the larger commercial customer-sited use cases, a New York City residential profile[34] was modeled to explore the benefit of storage under Con Ed's time of use (TOU) optional rate and the Smart

32 NPV of energy and demand charge savings over 10-year project lifetime

33 Rider Q demand charge windows are locational dependent (specific to a customer's CSRP network). For simplicity, only one window was modeled from 2-6pm across all customers. Bill savings results under this tariff could therefore vary considerably.

34 EIA OpenEI database. https://openei.org/datasets/files/961/pub/RESIDENTIAL_LOAD_DATA_E_PLUS_OUTPUT/BASE/. Electric end uses summed to total load for representative shape; profiles and end uses assumed to be representative; thermal applications fueled by gas are not considered.

Home Rate (SHR) demo. The SHR offers customers more dynamic pricing, in addition to $/kW demand charges, with the goal of better energy management and distributed energy resource response. The results below show the bill savings benefits and BICOS for a customer who installs storage on both the optional TOU rate and SHR demo. Higher storage benefits are achieved on the SHR by realizing demand bill savings.

Table 7. Residential Use Case Results: Con Ed's Time of Use Rate vs. Smart Home Rate[35]

	Residential *SC1 Rate 2*	**Residential** *Smart Home Rate*
Energy Bill Savings ($/kW-yr)	$320	$93
Demand Bill Savings ($/kW-yr)	-	$347
BICOS ($/kWh)	$315	$451

B.5 Distribution System Analysis

Distribution system storage can increase the efficiency, flexibility, and stability of the distribution grid. Energy storage can provide local capacity that defers costly transmission and distribution (T&D) system upgrades, and it can act as a distributed power source that serves peak load. These capabilities could also enable the retirement of aging peaker units with high emission rates, potentially providing substantial health benefits and potentially addressing environmental justice concerns. Finally, storage can facilitate the grid integration of renewables and support voltage and power quality at the distribution level.

The distribution system use cases represent scenarios where storage is not paired with onsite load, but rather is connected directly to the distribution grid or paired with a distribution-connected DER like community solar projects. For this application, we investigated how a single storage device can (and sometimes cannot) provide services across multiple value streams. These use cases examine the current project economics for distribution system energy storage and highlight current barriers to replicable, scalable distribution system storage projects as well as near-term actions to address them.

B.5.1 Step 1: Use Cases Examined

Distribution system use cases were modeled under the VDER framework, where energy storage is compensated for energy, capacity and demand reduction delivered to the grid.[36] Participation in the wholesale ancillary services (AS) markets was modeled as an additional revenue stream for specific cases. Storage was also modeled as providing distribution system relief as a non-wires alternative (NWA) that deferred the need to upgrade a hypothetical substation. In these NWA use cases, the storage received compensation for distribution relief in addition to energy, capacity and ancillary service payments (i.e. NWA+[37]). Finally, a community distributed generation (CDG) use case was modeled assuming a paired solar PV + storage system connected to the distribution grid. Distribution system use cases were modeled in Con Ed, LIPA, NatGrid and Central Hudson Gas & Electric (CHG&E) service territories. A summary of the

[35] For the SHR use case storage is sized at 25% of the residential customer's peak (0.70 kW), 4-hour duration (2.8 kWh).
[36] Environmental impact and locational system relief were also examined but not assumed across distribution system use cases.
[37] All NWA cases are NWA+ cases in this section as they reflect stacked distribution and bulk/wholesale values.

distribution system use cases is shown in the table below. Detailed assumptions and sources for these use cases can be found later in this section.

Table 8. Distribution System Use Cases

Use Case	Utility	Description	Value Streams
Standalone VDER	Con Ed, LIPA, NatGrid	Storage connected to distribution grid and compensated at utility value stack	VDER stack (energy, capacity, demand reduction), sensitivity including ancillary services
NWA+	Con Ed, LIPA	Storage managing load at distribution substation, otherwise participating in wholesale market	Distribution deferral value, energy, capacity, ancillary services; sensitivity including regulation
CDG	CHG&E	Paired PV and storage connected to distribution grid and compensated at value stack	VDER stack (including Market Transition Credit + Environmental value)

Value Streams

As described above, the simplest distribution system use case was assumed to receive compensation according to the VDER framework. The specific revenue streams available were energy, capacity (ICAP) and distribution demand reduction value (DRV) payments.[38] Storage charging was assumed to be at the locational-based marginal energy price (LBMP), and an annual contract demand from the applicable utility's retail standby tariff was applied based on the peak load (charging) of the storage. NWA+ cases assumed a proxy distribution deferral value, and participation in the 10-minute sync (spinning) and 30-minute reserve AS markets with no restrictions on multiple or dual market participation aside from state of charge of the storage asset. Distribution relief was performed first. Participation in the frequency regulation market was modeled as a sensitivity for the NWA+ cases. Additional revenue streams are available to community distributed generation (CDG) projects, including the market transition credit and environmental value.[39]

[38] Demand reduction (DRV) payments assumed for first 3 years and removed for duration of project life.
[39] 100% residential subscribers were assumed, leading to 100% of MTC credit available for 25 years.

Use cases that were not modeled but may merit future analysis

Regenerative braking for the Metropolitan Transit Agency (MTA)

This is a unique use case for energy storage where the energy used for braking the MTA's NYC subway cars could be recovered rather than being wasted as heat, decreasing total and peak energy usage and producing major energy cost savings. There is prior NYSERDA-commissioned and other associated analysis demonstrating the economics of this particular use case, so it was not modeled specifically as part of this Roadmap, but it is a potential near-term opportunity that could provide multiple benefits.

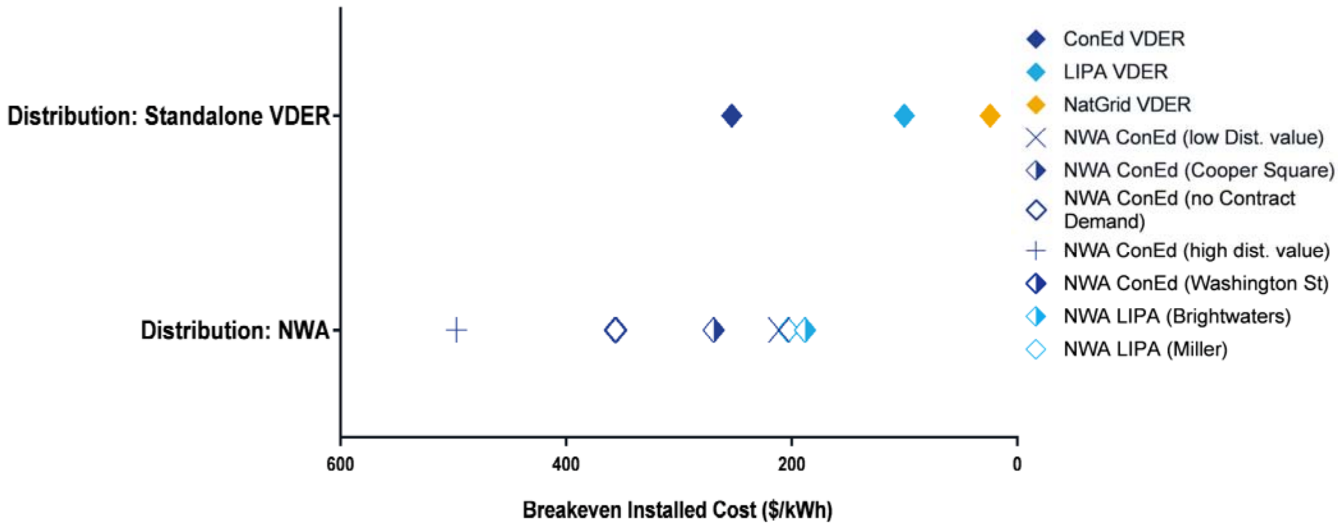
DC fast charging and heavy-duty vehicle/bus EV demand charge management

These are EV use cases associated with larger electrical loads needed for DC fast charging or larger vehicles. Use cases would examine pairing storage with charging infrastructure in order to manage demand and EV charging costs, which were not explicitly examined but could represent viable use cases in the near and medium term depending on how the EV market in New York evolves.

B.5.2 Step 2: Initial Results

Initial distribution system modeling was performed across the utilities and configurations described in Step 1. Storage operations were optimized to achieve the maximum potential benefit across all available revenue streams. A downward adjustment was then applied to the total achievable revenues to reflect imperfect foresight and market price risk. These adjusted revenue streams were used to calculate use-case specific BICOS values. Figure 9 shows the initial results for these use cases.

Figure 8. BICOS of Distribution System Use Cases[40]

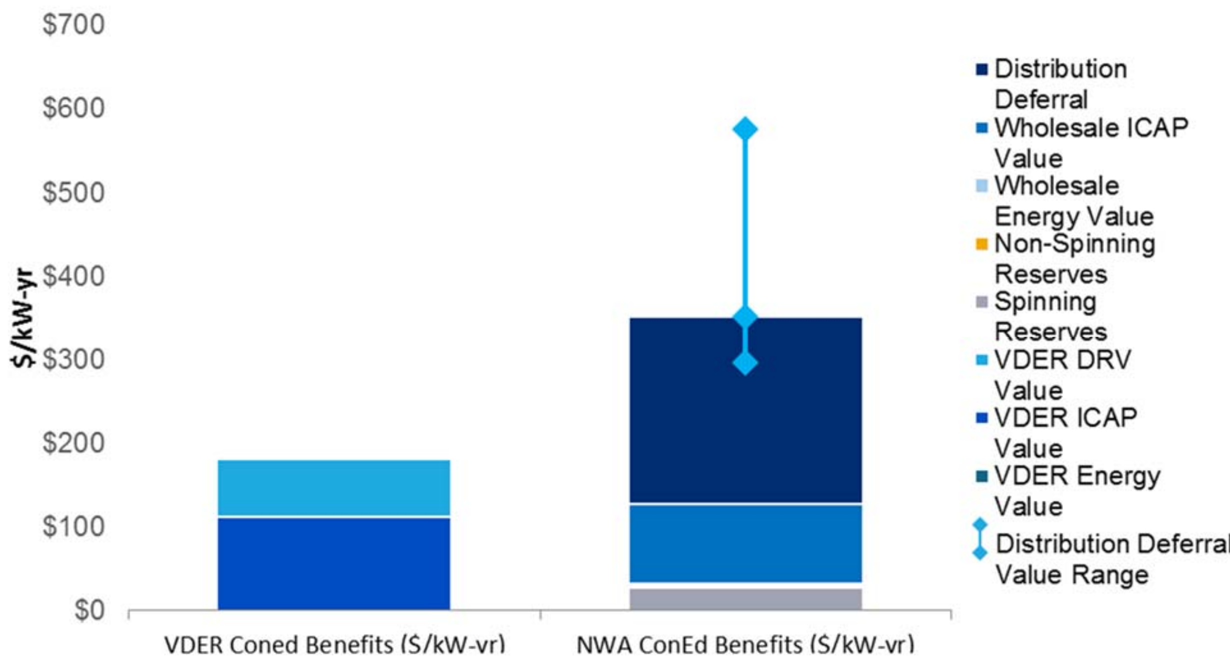


The initial BICOS results for stand-alone distribution system energy storage show that projects sited in Con Ed's service territory, and specifically New York City, are the most cost-effective today. The NWA+ results are less location-dependent, but this is because assumptions around deferral need and compensation[41] drive the economics of these use cases. Actual NWA+ economics will be highly project-specific, so the results presented here should be interpreted only as illustrative. The breakdown of modeled benefits for the Con Ed standalone VDER and NWA+ use case are shown below. As discussed below, the value of distribution deferral is highly variable; a range of expected value is represented below. This range was developed by varying the assumed DRV + LSRV proxy distribution deferral value by negative 25 percent to positive 100%.

[40] VDER Assumptions: Sized at 1 MW 4 hour. Discharge compensation at VDER stack (LBMP, ICAP, DRV value lock for 7 years), charging at contract demand + LBMP. 3rd party financed: 100% equity @ 12% WACC & 12% discount rate. 10% de-rate applied to revenues to reflect real world scenario without perfect foresight. NWA Assumptions: Sized at 5% of substation peak load, 6-hour duration. Discharge compensation at estimated NWA value (DRV + LSRV), LBMP arbitrage, ICAP & spinning reserves; charging at contract demand + LBMP. 3rd party financed: 50% equity @ 12% and 50% debt @ 6% for an 8.2% WACC & discount rate. 10% de-rate applied to wholesale revenues to reflect real world scenario without perfect foresight. "No Contract Demand" shown for Cooper Square with utility financing (48% Equity @ 9% and 52% Debt @ 4.74% for a 6.73% WACC & discount rate). High and Low Distribution values are shown for Cooper Sq. to reflect range of NWA compensation.

[41] A proxy value was used to approximate the NWA value which equaled the combined DRV + LSRV value which is approximately $340/kW-yr for Con Ed.

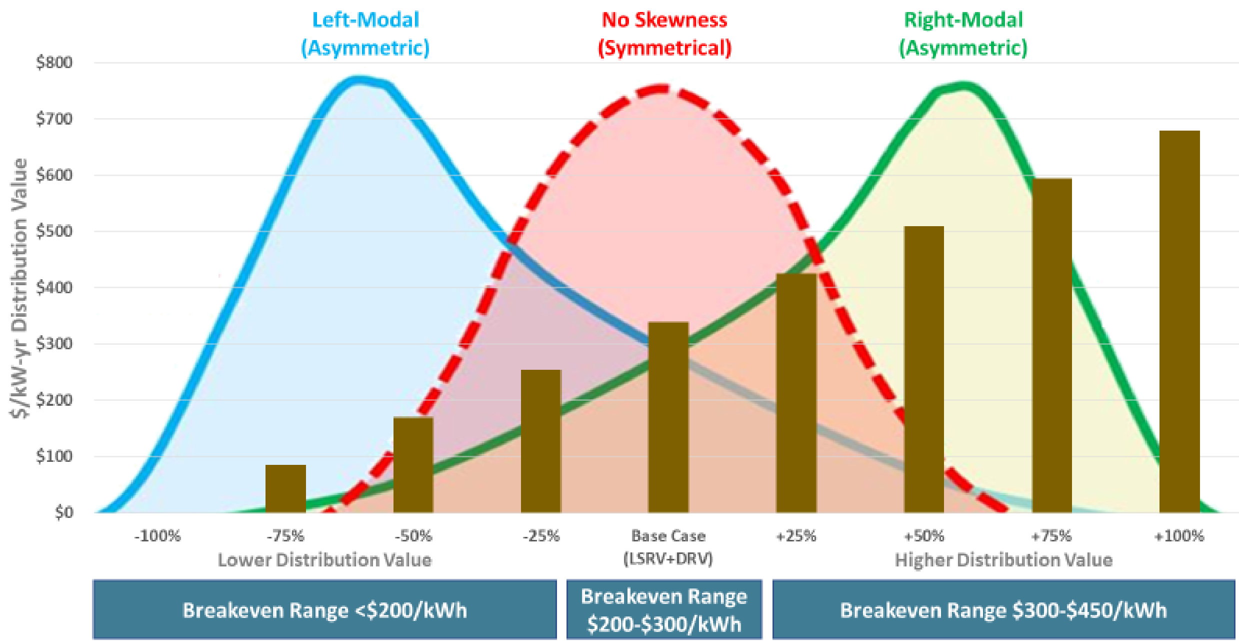
Figure 9. Benefits of VDER and Distribution Value (i.e. NWA) in Con Ed Illustrative Example[42]



The figure below shows an example range of distribution benefits around the base case proxy value (DRV+LSRV) that is assumed in the generic NWA+ use cases in this analysis. It is expected that these values will vary significantly depending on specific locational distribution value, but one reasonable way to think about the distribution is along the lines of a standard Bell curve – with the median set at the proxy value, with a number of values above and below the median, and with the potential for the highest values to be on the right-side tail of the curve. However, the actual range and shape of the curve are dependent on the specific drivers of T&D infrastructure investment and whether NWAs can defer that investment.

[42] Levelized $/kW-yr benefits over 10-year project lifetime. A range of -50% to 2 times the DRV + LSRV value is shown to capture variability in NWA value. VDER financing assumed 100% equity @ 12% WACC & 12% discount rate. NWA third party financing assumed 50% equity @ 12% and 50% debt @ 6% for an 8.2% WACC & discount rate. 10% de-rate applied to revenues to reflect real world scenario without perfect foresight. NWA results are for Con Ed Cooper Square substation.

Figure 10. Con Ed NWA or Distribution Value Range vs. BICOS Breakeven Ranges (Illustrative)



Results for Community Solar + Storage[43]

Solar PV + storage cases within the distribution system category were examined, focusing on community solar or community distributed generation (CDG) paired with storage participating in VDER. .

Community Solar + Storage

A Community Distributed Generation (CDG) Solar + Storage use case was modeled in Central Hudson under different assumptions for size and capacity credit. Both installed capacity (ICAP) Alternatives 2 and 3 were modeled. Energy storage size was also varied from 25 percent to 100 percent of the paired PV system rated capacity. The table below compares the BICOS of paired use cases with unpaired, standalone storage. In the paired case, storage is restricted to charging from the PV system only, and exports are credited with the market transition credit, the environmental value, energy and capacity. Standalone storage is compensated at energy, capacity and avoided demand. For both paired and unpaired use cases, ICAP Alternative 3 results in a higher breakeven cost, as storage can capture more capacity value. Under Alternative 2, when ICAP value is spread over 460 hours, storage must weigh the value of capacity compared to other value streams. Further, the 4-hour storage technology modeled cannot inject at its maximum capacity during all ICAP hours (which last for 5 hours). Under both Alternatives 2 and 3, the achieved capacity benefits are similar in both paired and unpaired use cases. However, achieved energy benefits and environmental value are higher in the paired case, which has higher overall benefits than in the standalone case. The results also show that increasing the inverter capacity of the battery without changing its duration negatively impacts the economics of these use cases. However, more detailed analysis should be performed to explore size variations and use cases in different locations.

Table 9: BICOS of CDG Solar + Storage

CDG Central Hudson	Storage in Paired PV System Under ICAP Alternative 2	Unpaired Storage Under ICAP Alternative 2	Storage in Paired PV System Under ICAP Alternative 3	Unpaired Storage Under ICAP Alternative 3
Battery Sized at 25% of PV (1 MW)	$315/kWh	$90/kWh	$365/kWh	$165/kWh
Battery Sized at 100% of PV (4 MW)	$220/kWh		$315/kWh	

B.5.3 Step 3: Stress Testing and Action Testing

Distribution system use cases differ from customer-sited use cases in that there are very few existing projects of this type; therefore, the Roadmap's distribution system use cases are more generic and hypothetical, particularly for stand-alone projects. For these reasons, stress testing was not performed on this set of cases. However, targeted policy and regulatory actions can enable medium- and longer-

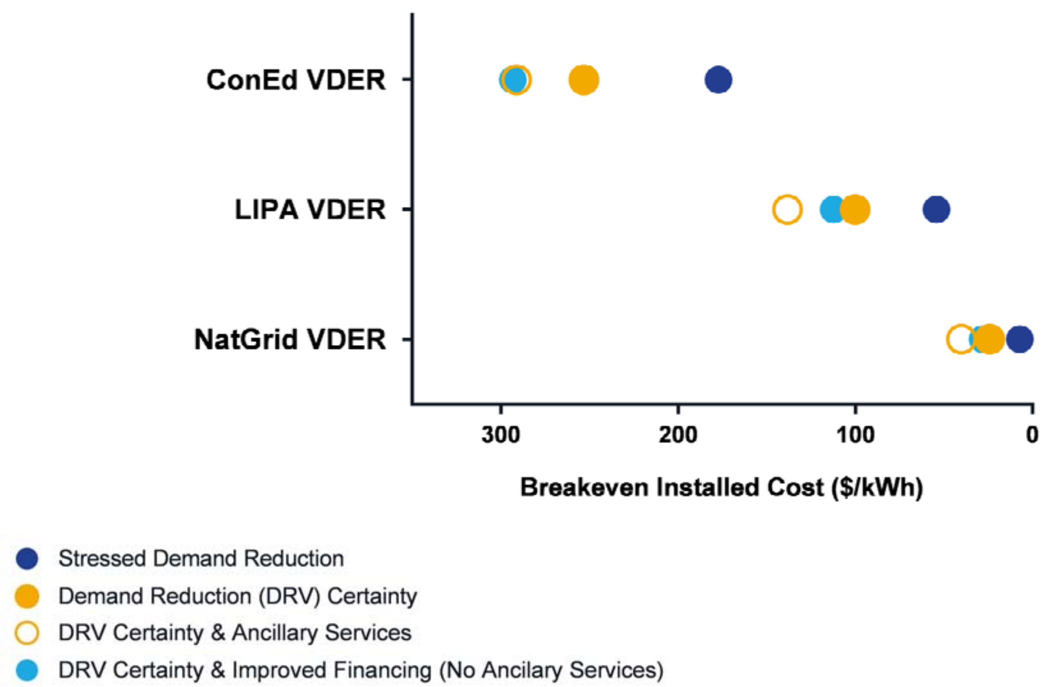
[43] Base Case Financing is 3rd party financed, 60% equity @ 12% and 40% debt @ 7% for a 9.3% WACC & discount rate. Calculation of the breakeven installed cost accounts for the inclusion of ITC in the paired case. Solar profile representative of fixed (roof mount), south facing system.

term deployment. These actions are described and tested below for stand-alone storage and NWA+ use cases.

Actions for Stand-Alone Distribution System Storage Compensated at VDER

As with the customer-sited cases, revenue certainty is necessary for viability and securing lower-cost financing for distribution system storage projects. DRV payments were therefore fixed and extended from 3 to 7 years. The impact of this action is specific to the DRV values of the utility, unlike the other VDER components. The increased ability to monetize revenue and greater revenue certainty unlocks lower-cost financing, which was tested as a separate action. Lower-cost financing improves the BICOS by around 15 percent compared to a 7-year DRV lock alone. An additional sensitivity was modeled (under the stressed financing scenario) where storage participates in the 10-minute sync and 30-minute reserve AS markets. The figure below summarizes these results.

Figure 11. Results for Action Testing Standalone Distribution System Storage Compensated at VDER[44]

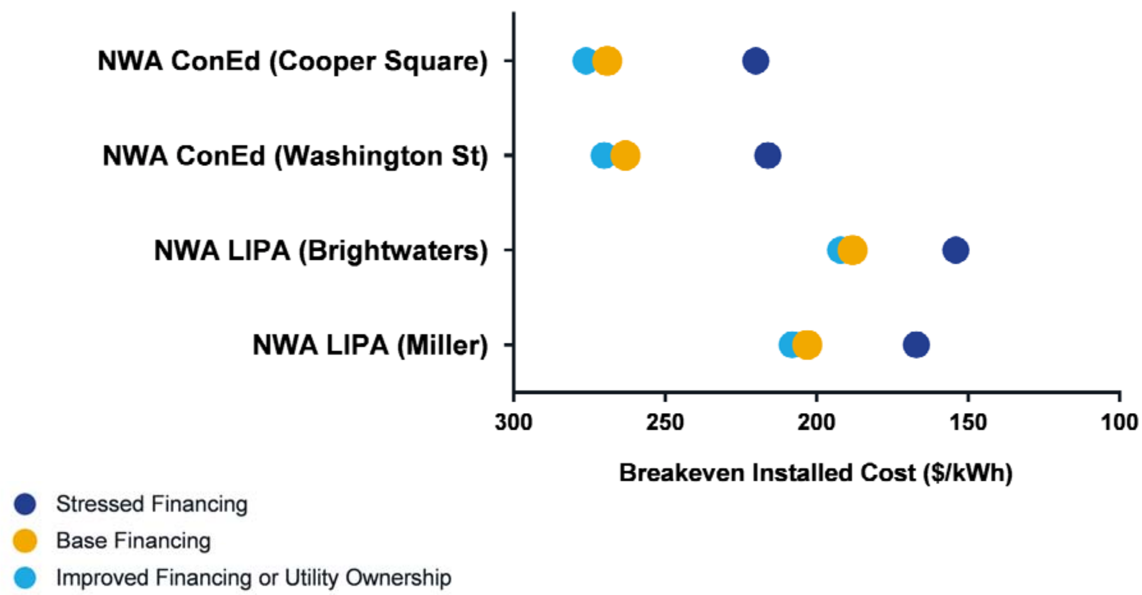


Actions for NWA+ Use Cases

NWA+ cases have a contracted term for NWA payments and were assumed to participate in the wholesale market during non-NWA hours. To stress these cases, a higher-cost financing structure (all equity) was assumed. This resulted in nearly a 20 percent reduction in BICOS. To test the impact of lower-cost financing, the utility's cost of capital was assumed.[45] This results in a slight increase in BICOS (<5 percent), as the base financing assumed was relatively similar to the utility-financed scenario.

[44] Stress Financing assumes 100% equity at a 12% WACC. DRV Certainty fixes DRV for 7 years. Improved Financing assumed 60% Equity @ 12% and 40% Debt @ 7% and 9.3% WACC. 10% de-rate applied reflect real world scenario without perfect foresight. See Appendix B.6 and Appendix E for further description on stress and action financing and assumptions.
[45] See Appendix B.6 and Appendix E for detailed assumptions.

Figure 12. Results: Action Testing for NWA+[46]



Summary of Action Testing

For the distribution system cases, the economics hinge on the **ability to access multiple benefit streams** (i.e., value stack) and the certainty around achieving these values over the project's lifetime. Total benefits depend on the level of individual VDER components for each utility. Con Ed, which has the highest value stack components, currently offers the greatest potential benefits for standalone storage.

The NWA+ use cases, while primarily illustrative, offer insight into the role that storage could play in avoiding high-cost distribution upgrades. An NWA or NWA+ contract offers a highly certain revenue stream from an extremely creditworthy counterparty (a utility), but the economics of these cases depend on the NWA contract value and terms. The ability to participate in wholesale markets, particularly capacity markets, during non-distribution relief hours significantly contributes to these projects' overall benefits.

B.5.4 Step 4: Key Takeaways

Distribution system key takeaways, based on the results presented above, are summarized in Section 3.2 of the Roadmap.

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[46] Stress Financing assumes 100% equity at a 12% WACC. Con Ed's weighted average cost of capital was assumed across all low financing NWA use cases, with 48% Equity @ 9% and 52% Debt @ 4.74% and 6.73% WACC. See Appendix B.6 and Appendix E for complete description of financing and assumptions. 10% de-rate applied to reflect real world scenario without perfect foresight.

B.6 Detailed Distribution System Results

The following tables detail the distribution system use case benefits and BICOS across each use case and utility.

Table 10. Breakeven Installed Costs ($/kWh) and Benefits ($/kW-yr) Across All Distribution System Stand-Alone VDER Use Cases

Con Ed VDER Results	Con Ed VDER (3-yr DRV)	Con Ed VDER (7-yr DRV)	Con Ed VDER (7-yr DRV) with AS
Total Modeled Benefits ($/kW-yr)	**$183**	**$250**	**$279**
Energy Value ($/kW-yr)	-	-	-
ICAP Value ($/kW-yr)	$109	$109	$109
DRV Value ($/kW-yr)	$74	$140	$140
Ancillary Services - Spinning Reserves ($/kW-yr)			$30
BICOS ($/kWh)	**$177**	**$253**	**$291**

LIPA VDER Results	LIPA VDER (3-yr DRV)	LIPA VDER (7-yr DRV)	LIPA VDER (7-yr DRV) with AS
Total Modeled Benefits ($/kW-yr)	$83	$119	$149
Energy Value ($/kW-yr)	-	-	-
ICAP Value ($/kW-yr)	$42	$42	$42
DRV Value ($/kW-yr)	$41	$77	$77
Ancillary Services - Spinning Reserves ($/kW-yr)			$30
BICOS ($/kWh)	$54	$100	$138

NatGrid VDER Results	NatGrid VDER (3-yr DRV)	NatGrid VDER (7-yr DRV)	NatGrid VDER (7-yr DRV) with AS
Total Modeled Benefits ($/kW-yr)	$44	$62	$74
Energy Value ($/kW-yr)	-	-	-
ICAP Value ($/kW-yr)	$24	$24	$24
DRV Value ($/kW-yr)	$20	$37	$37
Ancillary Services - Spinning Reserves ($/kW-yr)			$13
BICOS ($/kWh)	$7	$24	$40

Table 11. Breakeven Installed Costs ($/kWh) and Benefits ($/kW-yr) Across All Distribution System NWA+ Use Cases[47]

Third Party Owned NWA Results	Con Ed: Cooper Square (Spinning Only)	Con Ed: Cooper Square with Regulation	Con Ed: Washington Street (Spinning Only)	LIPA: Brightwaters (Spinning Only)	LIPA: Miller Place (Spinning Only)	LIPA: Miller Place with Regulation
Total Modeled Benefits ($/kW-yr)						
Energy Value ($/kW-yr)	$2	$1	$2	$5	$4	($1)
Capacity Value ($/kW-yr)	$96	$96	$96	$43	$43	$43
Distribution Deferral Value ($/kW-yr)	$224	$224	$215	$151	$165	$165
Ancillary Services ($/kW-yr)	$30	$27	$30	$30	$30	$18
BICOS ($/kWh)	$269	$287	$263	$188	$203	$238

Utility Owned NWA Results	Con Ed: Cooper Square (Spinning Only)	Con Ed: Cooper Square with Regulation	Con Ed: Cooper Square No Contract Demand	Con Ed: Washington Street (Spinning Only)	LIPA: Brightwaters (Spinning Only)	LIPA: Miller Place (Spinning Only)	LIPA: Miller Place with Regulation
Total Modeled Benefits ($/kW-yr)							
Energy Value ($/kW-yr)	$2	$1	$32	$2	$5	$4	($1)
Capacity Value ($/kW-yr)	$97	$97	$114	$97	$44	$44	$44
Distribution Deferral Value ($/kW-yr)	$224	$224	$202	$215	$151	$165	$165
Ancillary Services ($/kW-yr)	$30	$47	$26	$30	$30	$30	$70
BICOS ($/kWh)	$276	$294	$356	$270	$192	$208	$243

[47] Results are shown for the Base Case Financing Assumptions. A contract demand charge is applied to maximum peak demand unless otherwise noted.

B.6.1 Financing Assumptions and Sensitivities

Financing assumptions differ for distribution system VDER and NWA+ use cases, reflecting different levels of risk and uncertainty in the cash flows for these cases.

- **VDER**: The value stack in VDER is made up of several sources of revenue subject to various forms of risk including wholesale LBMPs, ICAP prices, and DRV (if it isn't locked for a certain term at the time of project commissioning). As a result, the base case reflects a stress financing scenario of 100 percent equity, with a hurdle rate of 12 percent. However, locking DRV prices for 7 years would give a portion of revenues much greater certainty, thereby enabling up to 40 percent of capital to be provided by debt. While debt was modeled as being repaid over 10 years, realistically this debt would be structured to be repaid during the period of locked-in DRV revenues (assumed to be 7 years in this example).

- **NWA:** The revenues from a 10-year NWA or NWA+ contract are highly certain and contracted with a creditworthy utility, potentially enabling higher leverage and lower-cost debt. A base financing structure of 50 percent debt (at a cost of 6 percent) and 50 percent equity was assumed. In addition, an all-equity stress case was considered. Finally, the utility's cost of capital was used to represent the optimistic post-action case.

Table 12. Distribution System Financing Scenarios

	VDER Third Party Owned		
	Stressed	**Post-Action:** **DRV Action**	**Post-Action:** **DRV + Financing Actions**
Percent of maximum achievable revenue	90% DRV zeroed out after 3 years	90% DRV zeroed out after 7 years	90% DRV locked for 7 years and zeroed out after 7 years
Financing	100% Equity 12% WACC	100% Equity 12% WACC	60% Equity @ 12% and 40% Debt @ 7% 9.3% WACC

	Third Party NWA		
	Base Case	**Stressed**	**Post Action:** **(Utility owned) as proxy**
Percent of maximum achievable revenue	90% of Wholesale Revenues (energy, capacity & AS)	90% of Wholesale Revenues (energy, capacity & AS)	90% of Wholesale Revenues (energy, capacity & AS)
Financing	50% Equity @ 12% and 50% Debt @ 6% 8.2% WACC	100% Equity 12% WACC	48% Equity @ 9% and 52% Debt @ 4.74% 6.73% WACC

Value Stack Assumptions

The following table shows the VDER values modeled for each utility. Energy and capacity price forecasts are described in Appendix C. Alternative 3 ICAP was modeled for all storage-only use cases. Both Alternatives 2 and 3 were modeled for the CDG Solar + Storage use case. DRV + LSRV was used as a proxy distribution deferral value for NWA+ use cases in Con Ed and LIPA.

Table 13. VDER Assumptions

2018	Con Ed	LIPA	NatGrid	Central Hudson
Annual Energy ($/MWh)	$35.95	$37.14	$22.13	$34.90
ICAP ($/kWh)	$74.83	$53.76	$16.80	$46.70
DRV ($/kW-year)	$199.40	$109.86	$61.44	$14.55
LSRV ($/kW-year)	$140.76	$54.93		

Distribution Deferral Assumptions

Distribution deferral use cases were modeled for Con Ed and LIPA. Actual distribution value (i.e. NWA) economics are highly project-specific and the modeled NWA use cases should be interpreted as illustrative.

Sample load curves and historical 8760 load data from Con Ed substations were used to model different Con Ed NWAs.[48] Deferral need was assumed during periods when substation load came within 10 percent of the maximum. LIPA provided load shapes and distribution deferral times for two substations. DRV and LSRV were spread equally across the hours of deferral need. Storage was sized at 5 percent of the peak station load and with a 6-hour duration for all NWA use cases in these illustrative examples.

B.7 Bulk System Analysis

Bulk system (or transmission-connected) energy storage can directly participate in NYISO markets, including energy, capacity, frequency regulation, and reserves markets. Storage can provide or enhance capacity by replacing or hybridizing conventional peaker plants; firm and time-shift renewable generation; provide ancillary services such as frequency regulation and spinning and non-spinning reserves; and potentially defer/avoid transmission upgrades. As New York transitions to a low-carbon electricity system, storage can also help to minimize the transmission congestion issues that could result from incorporating greater amounts of intermittent renewables, a benefit that will be of importance to the New York Metropolitan area.

Currently, the economically feasible applications in this category appear to be limited. This is changing as costs decline and as NYISO wholesale market rules evolve to allow multiple values to be stacked. The nearest-to-economic applications would relieve transmission congestion in Zones J and K, while providing energy arbitrage and frequency regulation in other markets and pairing with solar. The NYISO rules for direct market participation of energy storage resources are changing to accommodate the bulk system

[48] Cooper Square and Washington Street substation historical loads were modeled. Substation data available at: http://legacyold.Con Ed.com/dg/dsp/systemDataSharing.asp

services these resources could provide.[49] There are other potentially beneficial applications, such as replacing Zone J and K peaker units that are nearing the end of their useful lives with cleaner, non-fossil fuel burning resources.

B.7.1 Step 1: Use Cases Examined

In the bulk system use cases, energy storage was modeled as participating in the wholesale market across several NYISO market zones. This included access to the energy, capacity, reserves, and regulation markets. Each combination of these revenue streams was tested to determine the maximum amount of achievable revenue from each market, as well as how tradeoffs occur when multiple markets are available. Specific zones were also selected to model bulk paired solar + storage systems and quantify the interconnection and capacity benefits of these hybrid scenarios. The initial bulk system analysis focused on the economics of the current wholesale markets under one assumed set of wholesale price forecasts. Additional analysis was conducted to determine the economics of replacing an existing bulk or wholesale market generator (i.e., a peaker plant) with a new resource that is assumed to be able to perform similar services. The modeled bulk system use cases are summarized in the table below.

Table 14. Bulk System Use Cases

Use Case	NYISO Zones	Description	Market Participation/Value Streams
Standalone Bulk System Connected	A, D, G, J, K	Storage connected directly to bulk system and participating in wholesale markets	Energy, capacity, ancillary services (10- and 30-minute spinning, regulation). Variations modeled with energy only, energy and capacity, energy and ancillary services & regulation only. Variations with high renewable penetration energy price forecasts (Zones K & A only)
Paired Bulk System Connected Solar PV + Storage	A, D, K	Storage paired onsite with PV and participating in wholesale markets	Energy, capacity, REC value, interconnection value
Peaker Replacement	Statewide	Storage replaces peaking power plant	Peaker replacement value

[49] See The New York Independent System Operator (NYISO), *The State of Storage: Energy Storage Resources in New York's Wholesale Electricity Markets*, December 2017. https://home.nyiso.com/wp-content/uploads/2017/12/State_of_Storage_Report_Final_1Dec2017.pdf

Use cases that were not modeled but may merit future analysis

Hybrid wind and storage

This use case could offer significant siting, interconnection, and firming benefits for wind projects. In addition, many of the benefits of wind + storage may not necessarily hinge on co-location, and further analysis should be pursued as this application evolves across the U.S. This use case was demonstrated by a LIPA procurement for offshore wind and energy storage that procured 90 MW of wind and 40 MWh of storage that provided better economics than if each asset were individually procured.

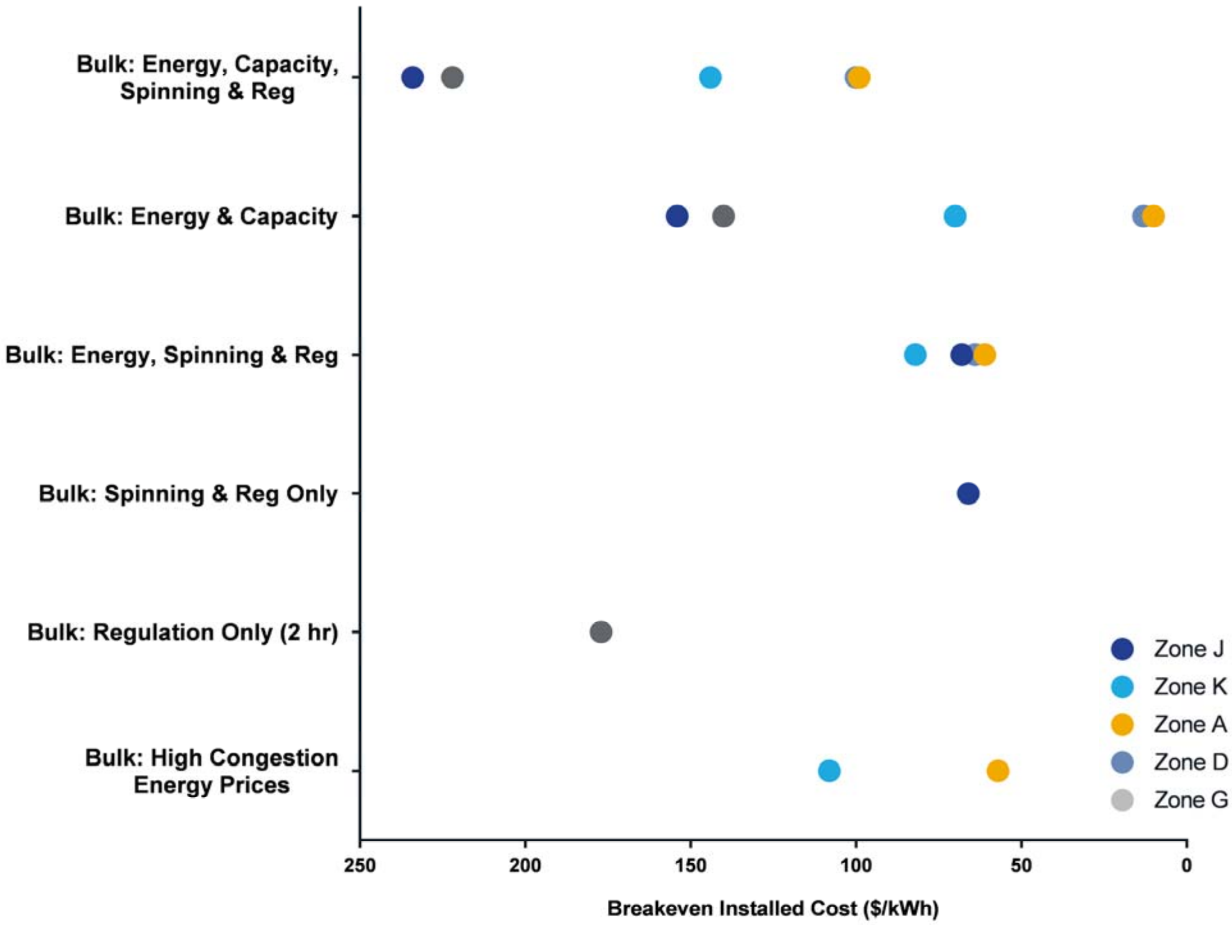
Transmission deferral and avoidance

This use case is another opportunity for storage, especially when combined with wholesale market revenues. Analytically, this application resembles the NWA use case except that it applies to the bulk or NYISO system, where storage would be considered another type of transmission solution; and like an NWA, the value would be highly specific to the transmission project or need being addressed. Overcoming challenges associated with this use case would involve modifying existing NYISO transmission planning and procurement processes, as well as resolving jurisdictional issues related to storage operating as both a market and regulated rate of return asset.

B.7.2 Step 2: Initial Results

Initial bulk system modeling was performed across the zones and configurations described in the table below. Storage operations were optimized to achieve the maximum potential benefit across all available wholesale market revenue streams. A downward adjustment was then applied to the total achievable revenues to reflect imperfect foresight and market risk. These adjusted revenue streams were used to calculate use-case specific BICOS values. The figure below shows the initial results for the bulk system use cases.

Figure 13. BICOS of Bulk System Use Cases[50]



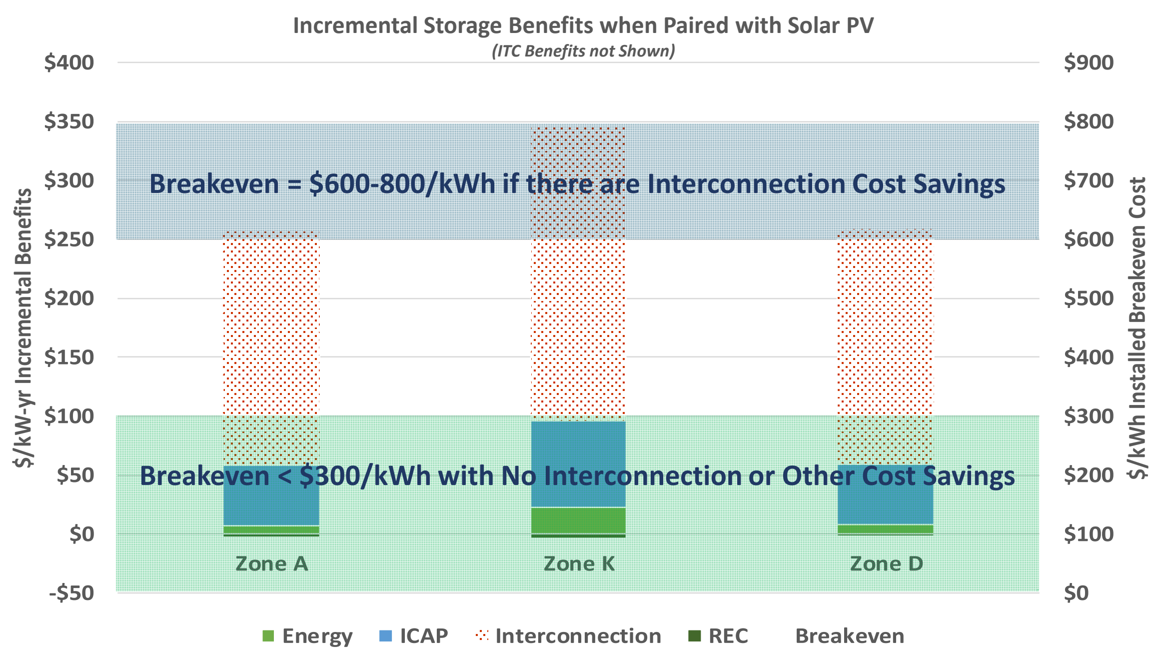
Even in the use cases with access to all wholesale markets and in highly constrained zones, the economics of bulk system storage are challenging today based on the forecasted wholesale market values that are assumed in this analysis. However, these use cases begin to become economical as costs decline within the next 3-5 years.[51]

[50] Base case, third-party financing assumed: 60% equity @ 12% and 40% debt @ 7% for a 9.3% WACC & discount rate. 10% De-rate applied to all revenues to reflect real world scenario without perfect foresight.
[51] Durations of 4-hours were assumed across all use cases unless otherwise specified. Shorter duration batteries have lower upfront costs and could improve the economics of these use cases.

Bulk System Solar + Storage Results and Discussion[52]

Solar + Storage Discussion

The paired solar + storage use cases perform significantly better than do stand-alone bulk system storage. In this use case, storage is assumed to help reduce bulk interconnection upgrades/costs by managing PV output, which provides a significant avoided cost stream. Storage can also bolster the ICAP credit of a system from that of PV alone. Paired bulk system solar + storage use cases were modeled downstate in Zone K and upstate in Zones A and D. The graphic below illustrates the incremental benefits and BICOS of solar + storage vs. solar without storage in Zones A, D and K. The corresponding breakeven costs are approximately $600/kWh for Zones A and D, and over $900/kWh in Zone K. However, if avoided interconnection costs are not assumed the installed breakeven costs decrease to less than $100/kWh.

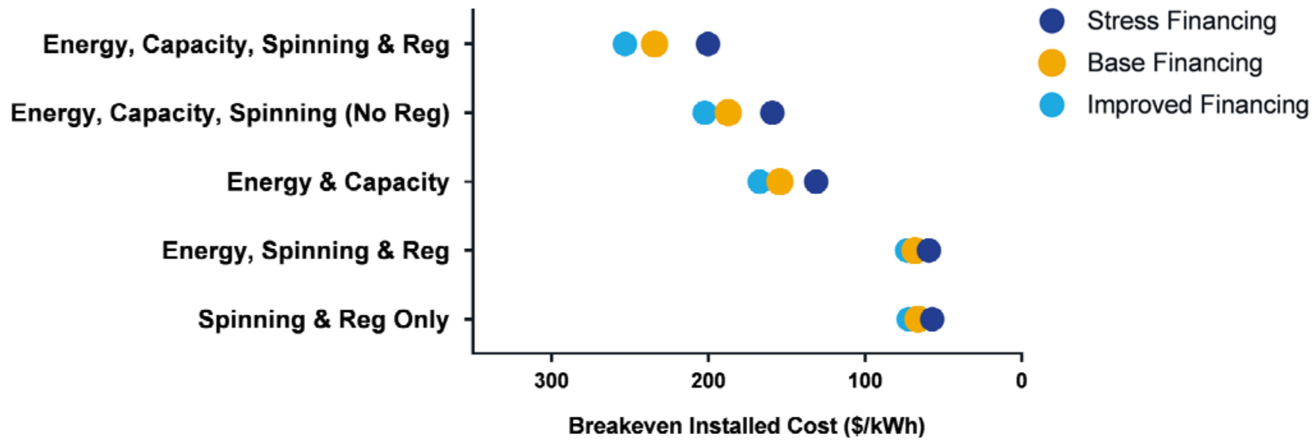


B.7.3 Step 3: Stress Testing and Action Testing

The market combinations covered in the initial set of bulk system use cases illustrate both the relative importance of the different value streams and the tradeoffs that occur when storage co-optimizes across several markets. Stress testing was therefore limited to the impact of higher-cost financing, which decreased the BICOS by around 15 percent (see the figure below). Specific, targeted actions can help bulk system storage project economics. These actions, described in Step 4 below, can increase the ability of projects to secure and monetize revenue and access lower-cost financing. The BICOS increased by around 8 percent when lower-cost financing was assumed. The impact of higher- and lower-cost financing on project economics for bulk system use cases in Zone J can be seen in the figure below.

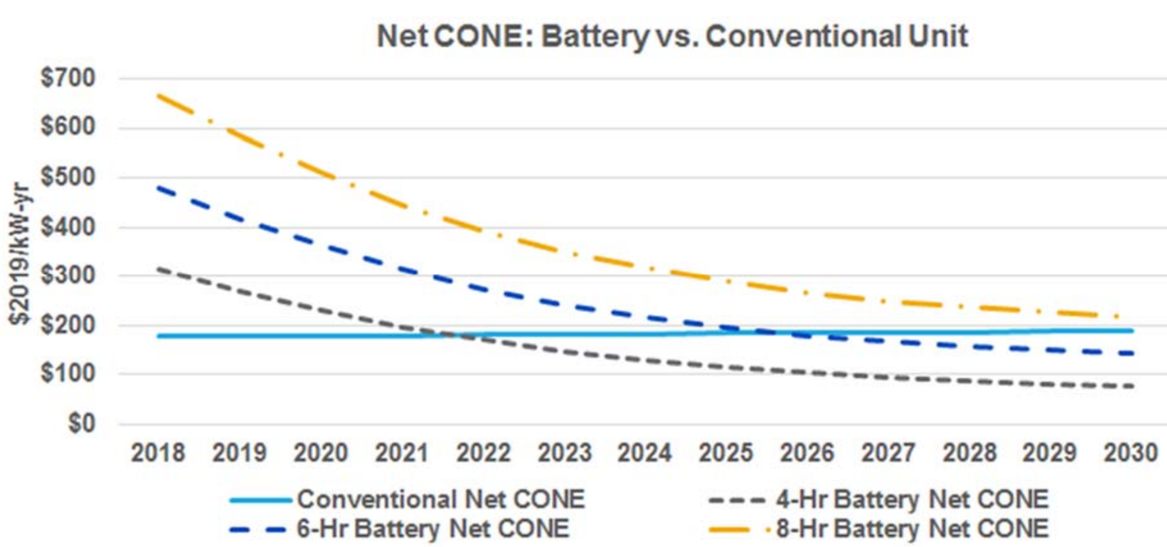
[52] Interconnection savings valued at 10¢/W downstate, 12.5¢/W upstate. 2017 Tier 1 REC Sale Price of $21.16/MWh assumed. 4 MW PV, 1 MW 4-hour storage sizing assumed. Storage charges from PV only. Base case, third-party financing assumed: 60% equity @ 12% and 40% debt @ 7% for a 9.3% WACC & discount rate. 10% De-rate applied to all revenues to reflect real world scenario without perfect foresight. Solar profile representative of fixed (roof mount), south facing system.

Figure 14. Results: Stress Testing and Action Testing for Bulk System Storage (Zone J)[53]



Net CONE Discussion

Another way to examine the economics of energy storage is in the context of the cost of new entry (CONE), or the capacity cost of a new resource net of any wholesale market revenues it earns. The figure below compares the net CONE between a new lithium-ion battery solution and a conventional unit (a Siemens Gas Turbine SGT6-5000F) for providing NYISO capacity services, based on the NYISO 2017 ICAP Demand Curve Reset analysis. As shown in the figure, new storage is expected to cross over as early as 2022-2023 for 4-hour batteries and later for longer-duration batteries. This would be relevant to a scenario where one or more conventional peaking units are retired and a new resource is needed for replacement. Note that this net CONE analysis is based solely on economics and does not address reliability needs (i.e., duration) of replacement resources, which depend on the resource being replaced, the reliability services it provides, and the underlying system conditions both now and in the future.



B.7.4 Step 4: Key Takeaways

The bulk system key takeaways, based on the results presented above, are summarized in Section 3.3 of the Roadmap.

B.8 Detailed Bulk System Results

The following table details the distribution system use case benefits and BICOS across each use case and utility.

Table 15. Breakeven Installed Costs ($/kWh) and Benefits ($/kW-yr) Across All Bulk System Use Cases

Bulk System Use Cases: Zone J	Bulk: Energy, Capacity, Spinning & Reg	Bulk: Energy & Capacity	Bulk: Energy, Spinning & Reg	Bulk: Spinning & Reg Only	Bulk: Energy, Capacity, Spinning (No Regulation)
Total Modeled Benefits ($/kW-yr)	**$196**	**$140**	**$82**	**$81**	**$162**
Energy Value ($/kW-yr)	$8	$28	$8	-	$24
Capacity Value ($/kW-yr)	$112	$112	($3)	-	$112
Spinning Reserves ($/kW-yr)	$9	-	$9	-	$27
Regulation ($/kW-yr)	$67	-	$67	$81	-
BICOS ($/kWh)	**$234**	**$154**	**$68**	**$66**	**$187**

Bulk System Use Cases: Zone A	Bulk: Energy, Capacity, Spinning & Reg	Bulk: Energy & Capacity	Bulk: Energy, Spinning & Reg	Bulk: High Congestion Energy Prices
Total Modeled Benefits ($/kW-yr)	**$134**	**$82**	**$91**	**$108**
Energy Value ($/kW-yr)	$18	$38	$18	$65
Capacity Value ($/kW-yr)	$43	$43	$1	$43
Spinning Reserves ($/kW-yr)	$10	-	$10	-
Regulation ($/kW-yr)	$63	-	$63	-
BICOS ($/kWh)	**$144**	**$70**	**$82**	**$108**

[53] Stress Financing is assumed at 100% equity and 12% WACC. Improved Financing is assumed at 45% Equity @ 12% and 55% Debt @ 6.5% 8% WACC. 10% De-rate applied to all revenues to reflect real world scenario without perfect foresight. See Appendix B.8 and Appendix E for complete description of stress and action financing and assumptions.

Bulk System Use Cases: Zone A	Bulk: Energy, Capacity, Spinning & Reg	Bulk: Energy & Capacity	Bulk: Energy, Spinning & Reg	Bulk: High Congestion Energy Prices)
Total Modeled Benefits ($/kW-yr)	**$103**	**$40**	**$77**	**$73**
Energy Value ($/kW-yr)	($1)	$15	($1)	$48
Capacity Value ($/kW-yr)	$25	$25	($1)	$25
Spinning Reserves ($/kW-yr)	$1	-	$1	-
Regulation ($/kW-yr)	$77	-	$77	-
BICOS ($/kWh)	**$99**	**$10**	**$61**	**$57**

Bulk System Use Cases: Zone G	Bulk: Energy, Capacity, Spinning & Reg	Bulk: Energy & Capacity	Bulk: Energy, Spinning & Reg	Bulk: Regulation Only
Total Modeled Benefits ($/kW-yr)	$187	$130	$82	$96
Energy Value ($/kW-yr)	$6	$25	$6	-
Capacity Value ($/kW-yr)	$104	$104	($1)	-
Spinning Reserves ($/kW-yr)	$9	-	$9	-
Regulation ($/kW-yr)	$68	-	$68	$96
BICOS ($/kWh)	$222	$140	$68	$177

Bulk System Use Cases: Zone D	Bulk: Energy, Capacity, Spinning & Reg	Bulk: Energy & Capacity	Bulk: Energy, Spinning & Reg
Total Modeled Benefits ($/kW-yr)	$104	$43	$79
Energy Value ($/kW-yr)	$1	$18	$1
Capacity Value ($/kW-yr)	$25	$25	-
Spinning Reserves ($/kW-yr)	$2	-	$1
Regulation ($/kW-yr)	$76	-	$76
BICOS ($/kWh)	$100	$13	$64

B.8.1 Financing Assumptions and Sensitivities

For bulk system cases, financing is based on a series of market value streams with a high degree of merchant risk. Bulk system merchant risk is well understood and common in the financing of peaking power generation assets. The Roadmap's base case financing structure includes 40 percent debt (at a cost of 7 percent) and 60 percent equity. Two variations were considered: an all-equity stress case, and an optimistic post-action case that reflects typical financing structures for peaking power plants, which have a similar level of merchant risk exposure. This optimistic case includes 55 percent of capital from debt (at a lower cost of 6.5 percent) and 45 percent equity.

Table 16. Bulk System Financing Assumptions

	Wholesale Third Party Owned		
	Base Case	**Stressed**	**Post-Action** **More revenue certainty**
Percent of maximum achievable revenue	90% of Wholesale Revenues	90% of Wholesale Revenues	90% of Wholesale Revenues
Financing	60% Equity @ 12% and 40% Debt @ 7% 9.3% WACC	100% Equity 12% WACC	45% Equity @ 12% and 55% Debt @ 6.5% 8% WACC

B.8.2 Wholesale Market Participation Assumptions

The following assumptions were used to approximate wholesale market participation of energy storage in bulk system cases.

Energy Market: Congestion Assessment and Resource Integration Study (CARIS) forecasts were used to generate annual Locational Based Marginal Prices (LBMPs) for energy values for each zone.[54] These annual $/MWh values were converted into hourly $/kWh values using E3's in-house hourly shaping scalars, which are based on historical price shapes. Energy storage charges and discharges at the LBMPs.

Capacity Price Forecast: DPS' annual projected ICAP values by zone from the 2017 forecast were used.[55] The battery delivers capacity during calls and can provide other services at other times.

Ancillary Services: Ancillary Services (AS) prices were used in distribution and bulk system use cases. Historical day-ahead prices were used for year 2015, which was found to be a relatively average year in terms of prices and volatility.[56] AS services modeled include regulation services, 10-minute sync, and 30-minute reserve. A 4-hour minimum requirement was enforced for providing 30-min and 10-min sync. To bid in the market, the battery must have enough charge/discharge capability (kW) and enough energy/headroom (kWh) to deliver the full-quantity bid. 30-min and 10-min sync did not influence the battery's state of charge. The energy impact of the regulation services was 15 percent of bidding capacities, and the probability of having upward and downward signal were assumed to be the same.

[54] 2017 Congestion Assessment and Resource Integration Study. http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_(CARIS)/CARIS_Final_Reports/2017-Report-CARIS2017-Appendix-B-J-FINAL.pdf

[55] ICAP Monthly Price Forecasts are based on the 2017 Load & Capacity Data "Gold Book". Prices can be found at: http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BFB2EBAEA-7DF0-48B9-A479-B2F742B74D02%7D; Gold Book can be found at: https://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2017_Load_and_Capacity_Data_Report.pdf

[56] Data accessed from NYISO's Decision Support System (DSS) http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp?report=dam_ancillary

C General Use Case Assumptions

The following sections detail the common assumptions across all use cases analyzed as part of this Roadmap, the specific assumptions for each use case category, and the detailed results from use case modeling.

Price Forecasts

The following energy and capacity price forecasts were used across all use cases. For customer-sited use cases, energy forecasts were used for the hourly retail energy commodity component of customers' bills. Capacity price forecasts are used for NYISO Demand Response program compensation. For distribution sited use cases, energy and capacity forecasts were used to determine the corresponding components of the VDER stack. For NWA+ and bulk system use cases, energy and capacity price forecasts provided data for the wholesale market prices and potential revenue streams for energy storage.

> **Energy Price Forecast:** Congestion Assessment and Resource Integration Study (CARIS) forecasts were used to generate annual Locational Based Marginal Prices (LBMPs) for energy values for each zone.[57] These annual \$/MWh values were converted into hourly \$/kWh values using E3's in-house hourly shaping scalars, which are based on historical price shapes.
>
> **Capacity Price Forecast:** DPS' annual projected ICAP values by zone from the 2017 forecast were used.[58] For capacity value Alternative 2, value is assigned to 460 summer hours (defined as the period starting with hour beginning 14:00 through hour beginning 18:00 for each day in June, July and August). Alternative 3, the 'Capacity Tag' approach, calculates capacity value as the monthly ICAP capacity prices multiplied by the output at the time of the single hour system peak. For LIPA ICAP Alternative 3, the top 10 annual hours are used.

Wholesale Market Participation Assumptions (NWA+ and Bulk System Use Cases Only)

> **Ancillary Services:** Ancillary Services (AS) prices were used in distribution and bulk system use cases. Historical day-ahead prices were used for year 2015, which was found to be a relatively average year in terms of prices and volatility.[59] AS services modeled include regulation services, 10-minute sync and 30-minute reserve. A 4-hour minimum requirement was enforced for providing 30-min and 10-min sync. To bid in the market, the battery must to have enough charge/discharge capability (kW) and enough energy/headroom (kWh) to deliver the full quantity bid. 30-min and 10-min sync did not influence the battery's state of charge. The energy impact of the regulation services was 15 percent of bidding capacities and the probability of having upward and downward signal were assumed to be the same.

The following technology assumptions are common across all use cases:

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[57] 2017 Congestion Assessment and Resource Integration Study.
http://www.nyiso.com/public/webdocs/markets_operations/services/planning/Planning_Studies/Economic_Planning_Studies_(CARIS)/CARIS_Final_Reports/2017-Report-CARIS2017-Appendix-B-J-FINAL.pdf

[58] ICAP Monthly Price Forecasts are based on the 2017 Load & Capacity Data "Gold Book". Prices can be found at:
http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BFB2EBAEA-7DF0-48B9-A479-B2F742B74D02%7D;
Gold Book can be found at:
https://www.nyiso.com/public/webdocs/markets_operations/services/planning/Documents_and_Resources/Planning_Data_and_Reference_Docs/Data_and_Reference_Docs/2017_Load_and_Capacity_Data_Report.pdf

[59] Data accessed from NYISO's Decision Support System (DSS)
http://www.nyiso.com/public/markets_operations/market_data/custom_report/index.jsp?report=dam_ancillary

Storage Technology Assumptions	Input
Lifetime	10 years (Stand-alone) or 25 years (Paired)
Charge/Discharge Capacity	Percentage of Peak Load (Customer), 1 MW (Distribution), and 10 MW (Bulk)
Discharge Duration	6 hours (NWA) or 4 hours (all other use cases)
Maximum Depth of Discharge	100%
AC/AC Roundtrip Efficiency (year 1)	85%

D Energy Storage Installed Cost Forecast

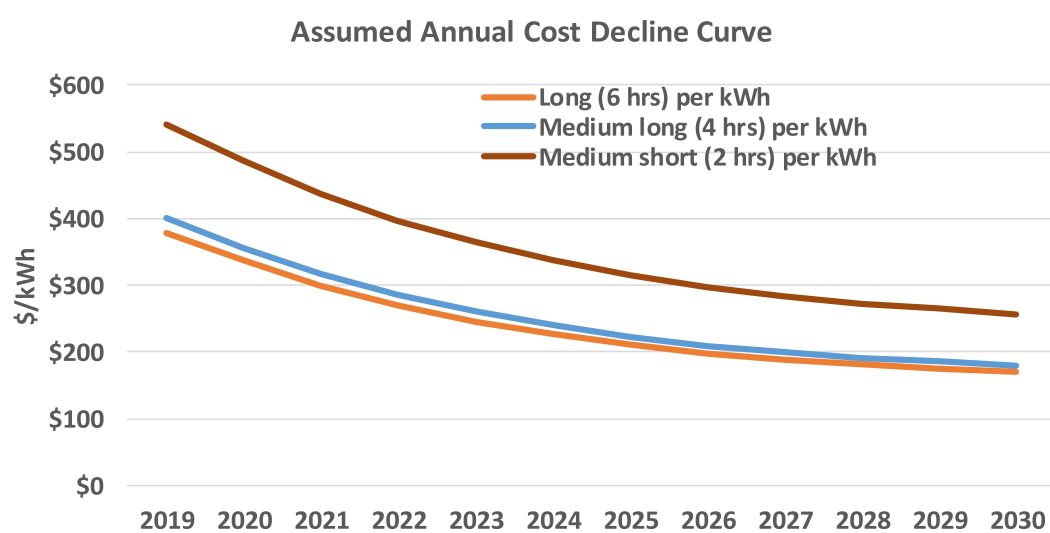
The following table contains the blended cost forecast that was used in this analysis, developed for the Acelerex energy storage study (see Appendix K). The applicable 2019 installed costs were used as a basis for the initial use case analysis with the appropriate adjustments for behind-the-meter and geographic considerations (if applicable). The forecasts in the later years were used to develop a range of when certain use cases could become economic based on the BICOS analysis, which further helps develop, inform, and guide the recommended actions in this Roadmap. This is a blending of various technologies that can meet the duration required. This does recognize, however, that lithium ion battery systems reflect almost 90 percent of the new installations and so cost declines are largely reflective of experience in li ion prices and forecasted cost decline as greater manufacturing scale is reached. As shown in the figure below, storage costs are expected to decline quite dramatically over the Roadmap horizon (2019-30) with significant cost declines occurring in the near-to-medium term (before 2025). Note that this forecast was developed from several market research firm and financial sources, including actual New York market data where available.

Figure 15. Energy Storage Installed Cost Forecast for New York State Used in the Roadmap

All costs are in 2019 $ and reflect all in front of meter installation cost including a basic estimate for land lease cost for a large bulk system and basic interconnection.
Local land costs, especially in NYC, can vary widely on top of these costs.
Add 50% multiplier from presented cost for customer load sited storage (behind a customer's utility meter).
1.25 multiplier for NYC Zone J installations and 1.10 multiplier for Long Island Zone K installations.

Long (6 hrs)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
per kW	$2,270	$2,020	$1,798	$1,620	$1,477	$1,360	$1,266	$1,191	$1,132	$1,087	$1,054	$1,022
per kWh	$378	$337	$300	$270	$246	$227	$211	$198	$189	$181	$176	$170
Medium long (4 hrs)												
per kW	$1,602	$1,426	$1,269	$1,144	$1,042	$960	$894	$841	$799	$767	$744	$722
per kWh	$401	$356	$317	$286	$261	$240	$223	$210	$200	$192	$186	$180
Medium short (2 hrs)												
per kW	$1,080	$972	$875	$795	$729	$676	$632	$596	$568	$546	$529	$514
per kWh	$540	$486	$437	$397	$365	$338	$316	$298	$284	$273	$265	$257
Short (half hour)												
per kW	$632	$569	$512	$465	$427	$395	$370	$349	$332	$320	$310	$301
per kWh	$1,260	$1,134	$1,021	$927	$851	$788	$737	$696	$662	$637	$618	$599

Cost and cost decline sources: Lazard Levelized Cost of Storage 2017, GTM Research, Bloomberg, Navigant Research and industry input



E Storage Financing Assumptions Background

Energy storage is an emerging asset class, and the contractual and financial structures of energy storage assets are still evolving. In addition, there will be wide variation in the financial structure backing different use cases, based on fundamental differences in risk and return.

Energy storage is also capital intensive, with relatively high upfront costs and lower ongoing costs of operation. Because of this capital intensity, financing costs can be a major factor in the competitiveness of energy storage in a specific project.

For this analysis, base financing assumptions were developed for each type of energy storage use case, which reflects the risks and profile of revenues available in each use case. In addition, sensitivities were developed around this base to reflect a high cost of capital, or a low cost of capital enabled by actions recommended in this Roadmap to enhance project bankability.

E.1 Sources of Risk in Energy Storage Projects

Financial structures are used to allocate risks among different investors in a project. Because of its ability to access multiple value streams from multiple sources, energy storage investments must manage a wide variety of risks. These risks generally break down into four categories, as described below.

Price Risks

Much of the value created by an energy storage asset comes from responding to prices. This includes managing customer demand charges, arbitrage between low and high-priced energy periods, capacity payments, demand response payments, and ancillary services payments. Some of these prices (e.g., rates and distribution-level demand response payments) are determined through regulatory processes which can provide for relatively greater stability of prices. Others (e.g., wholesale energy, capacity and ancillary services) are determined by the market and can vary widely from one year to another.

Changing Customer and System Needs

In addition to changing prices, energy storage assets may also face changing customer or system needs. For instance, a customer might make an equipment or operation change that changes the load profile from one with high, short-duration peaks that drive high demand charges, to one with longer-duration peaks that are more challenging to clip with energy storage that has a limited duration. Alternatively, distribution-level peaks might change in shape, leading to longer distribution-level demand response calls or calls on non-wires alternatives. These changes could reduce the value proposition of storage, for instance, if the same storage asset can deliver less of a reduction in peak demand of a customer or distribution substation.

Performance and Technology Risks

Energy storage technologies are rapidly evolving, and there are significant differences among storage technologies and equipment manufacturers. The number of cycles, charge and discharge rates, temperature management, and management and monitoring of the health of individual battery cells can all impact the lifetime and degradation of battery performance. In addition, realizing maximum revenue from multiple value streams requires optimization, good predictions of demand profiles and prices, and accurate representation of operational and warranty-based constraints. These risks are generally covered by equipment warranties and performance guarantees, which are as bankable as the counterparties providing them.

Counterparty Risks

An investor in an energy storage asset is also exposed to the creditworthiness of its counterparties. Some storage assets may receive contracted revenues from a utility with a good credit rating, while others depend on payments from commercial electricity users as part of a lease or shared savings agreement. The credit risk associated with counterparties is well understood but is a factor in the cost of capital for a project.

In addition, financing costs may be impacted by the value of an asset if the customer defaults. In this light, the ability to access VDER revenues provides a backstop source of value that may mitigate risk for customers with poor credit quality.

E.2 Impact on Investment Decision Making

These sources of risk differentially impact different types of investors, and debt and equity investors may value risky sources of value very differently.

Debt Investors

Lenders to a project expect reliable repayment of principal plus interest. The amount of debt that a project can support (if any) is determined by two key parameters: 1) a conservative estimate of revenues, which highly discounts risky sources of value, and 2) a debt service coverage ratio that ensures that even in a conservative cash flow scenario, there is a buffer between the amount of cash needed and amount of cash available for debt payments.

Equity Investors

Equity investors typically aim to meet a hurdle rate of return, which reflects their assessment of risk in the investment. An equity hurdle rate (after tax) of 12 percent IRR was assumed, which reflects a typical equity return for infrastructure assets exposed to some degree of market risk. However, this assessment has also discounted the amount of revenue that could be realized to account for some performance risk and market uncertainty, and equity would stand to benefit if these values were closer to optimal.

Further, equity investors are project owners who owe taxes on income from the projects, and benefit from tax benefits from depreciation and any applicable tax credits. These factors were considered as part of the driver of after-tax returns for equity investors.

E.3 Approach to Stress Testing

Base case financial structures for each type of use case are as follows:

- **Debt sized to provide adequate coverage of debt service under conservative assumptions** – evaluated the amount of debt a project could support under conservative cash flow assumptions.
- **Leverage determined at breakeven cost of storage** – compare the amount of debt that can be supported to the total project costs at the project breakeven cost to determine the appropriate amount of leverage in percentage terms.
- **Equity makes up the difference** – assume that equity provides the rest of the up-front capital needed by the project.
- **An after tax WACC determined using shares and costs of equity and debt** – calculate the weighted average cost of capital after tax using the proportions of debt and equity as determined

above, the interest rate for debt (which varies by case), and after-tax hurdle rate for equity (12 percent in all cases).

In addition, a stressed financial case as 100 percent financed with equity with a hurdle rate of 12 percent was modeled. This is intended to reflect an upper bound on financing costs. Post-action financing cases were determined for each type of use case based on the amount of risk reduction provided by policy actions, as well as the possibility of alternative financial structures supported by policy action.

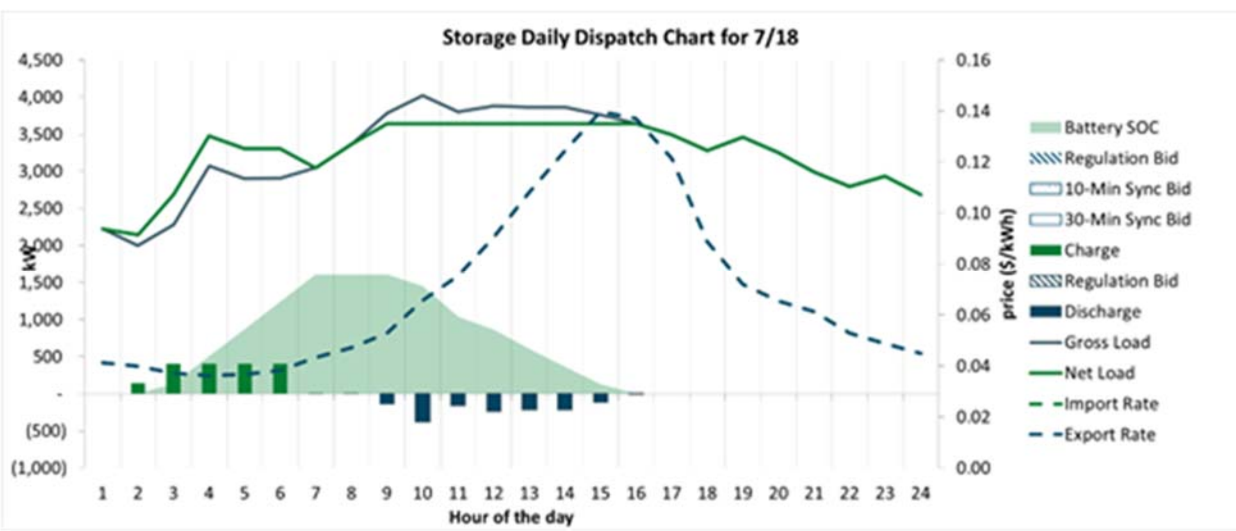
F E3 RESTORE Model and Use Case Dispatch Charts

As the market for energy storage (ES) assets has emerged, E3 developed the RESTORE tool[60], which simulates optimal operation over the life of different types of ES assets. The core "engine" of the tool is a price-taker optimal dispatch algorithm, which identifies the profit maximizing operation pattern for the ES facility given its size and performance characteristics, the revenue streams to which it has access, the market in which it is expected to operate, and a forecast of the applicable market prices for the services the ES asset will be providing (i.e., behind-the-meter bill savings or front-of-meter energy, capacity, regulation, reserves, resource adequacy prices, etc.). The tool is quite flexible in the types of ES asset types that can be evaluated (e.g., lithium ion, flow, pumped hydro, etc.) and it has been used for variety of purposes such as analyzing ES operational patterns and estimating lifecycle market revenues for developers, asset owners, and potential investors.

E3's RESTORE tool can dispatch both stand-alone storage and storage paired with PV optimally with co-optimization of multiple value streams by a mixed integer linear programming (MILP) algorithm. Value streams can include system level avoided costs, distribution avoided costs, ancillary services, customer demand charges, energy charges, and back-up power reliability values. The tool can be dispatched in customer or utility control mode. In customer control mode, the storage is dispatched to maximize customer revenue: reduce bills, increase back-up power reliability values, and increase ancillary services revenue if customers have access to AS markets. In utility control mode, storage is dispatched to reduce system costs.

The tool outputs hourly and annual dispatch and operational data, value streams and avoided costs. Sample dispatch charts are shown below for the three primary use case types included in this analysis.

Figure 16. Storage Dispatch Chart: Commercial Office During Peak Annual Load Day



[60] https://www.ethree.com/tools/restore-energy-storage-dispatch-model/

Figure 17. Storage Dispatch Chart: Commercial Office During Demand Response Call Day

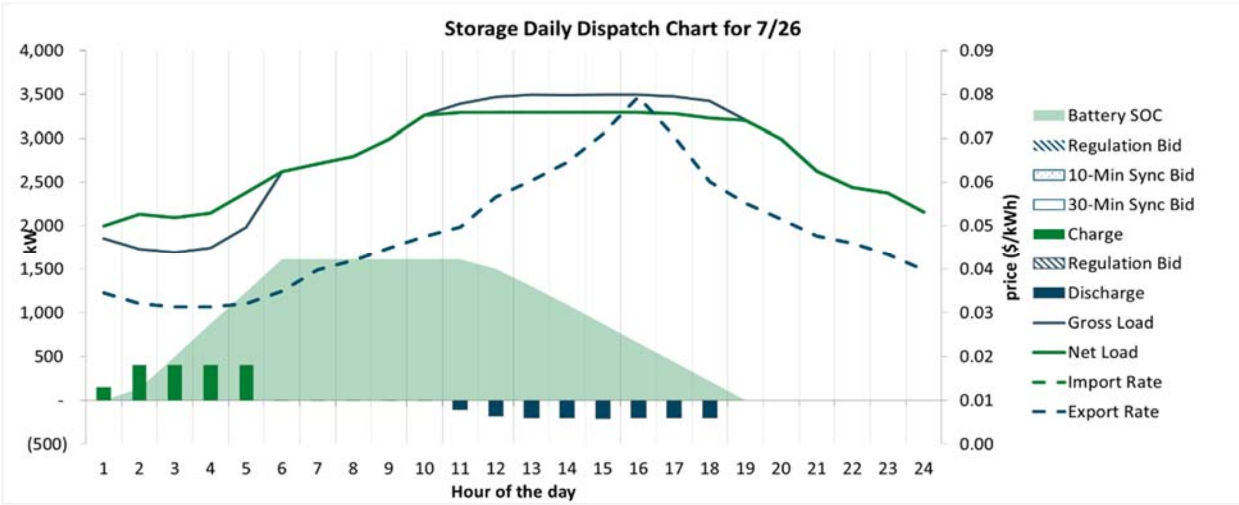
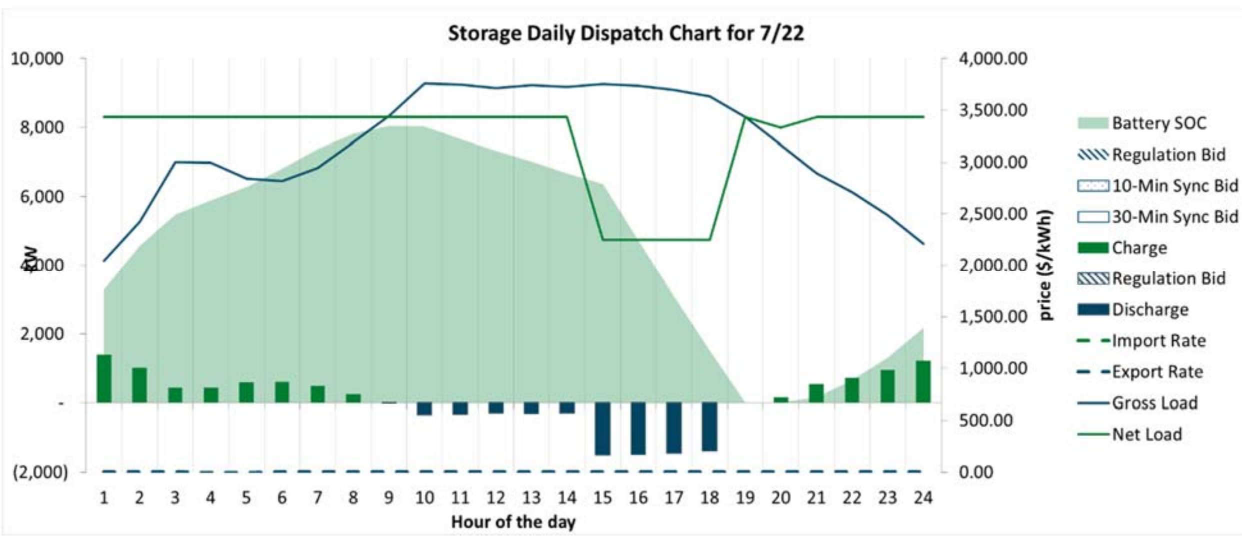


Figure 18. Storage Dispatch Chart: Commercial Office on SC9 Rate V Rider Q Tariff for Large Battery[61]



[61] At smaller battery sizes, Con Ed's Standby Rider Q Pilot generated comparable benefits to the existing Standby Rate. However, as battery size increases, customers on Rider Q can achieve higher benefits due to concentration load reduction during the 4-hour peak demand charge period (2-6pm in Figure 19 above). Storage modeled at 50% of customer peak load (2,000 kW), 4-hour duration resulted in this behavior.

Figure 19. Storage Dispatch Chart: Distribution System NWA During Distribution Relief[62]

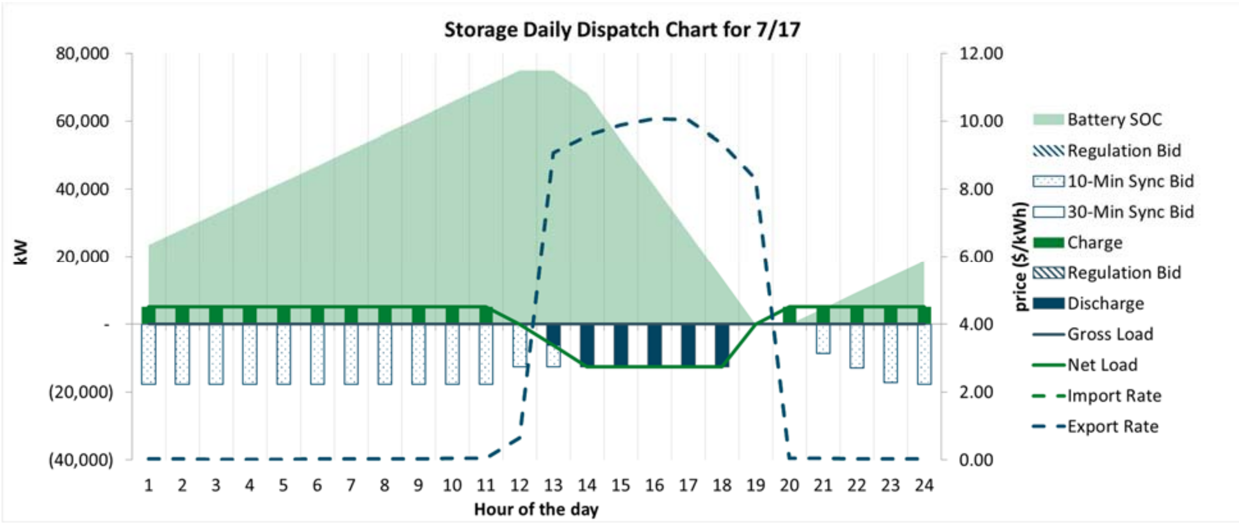
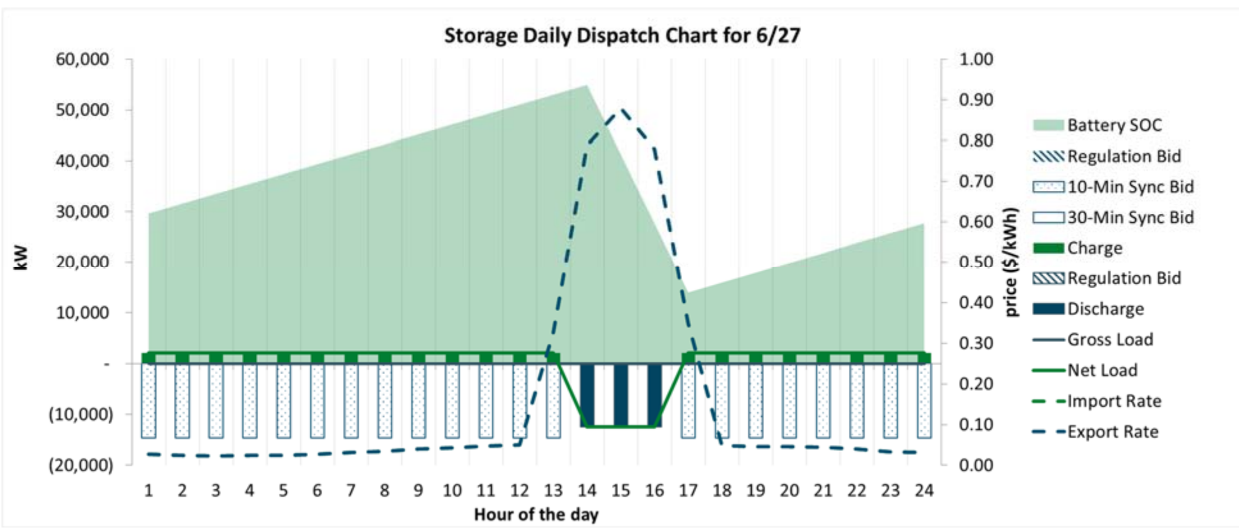


Figure 20. Storage Dispatch Chart: Distribution System NWA During ICAP Dispatch[63]



[62] Storage sized at 1 MW, 4-hour duration.
[63] Storage sized at 1 MW, 4-hour duration.

Figure 21. Storage Dispatch Chart: Bulk System During Energy Arbitrage[64]

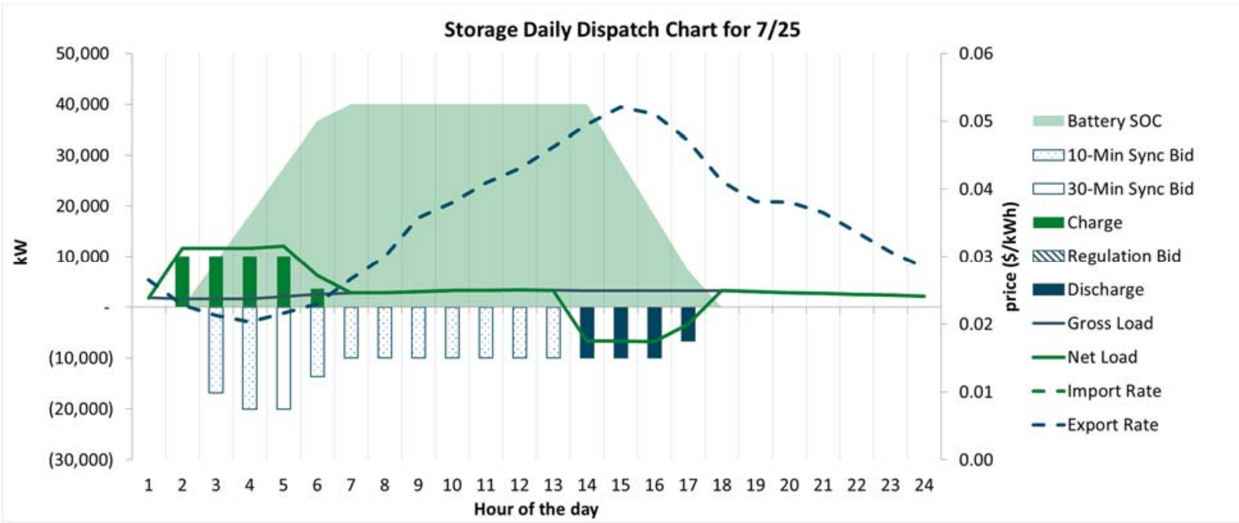
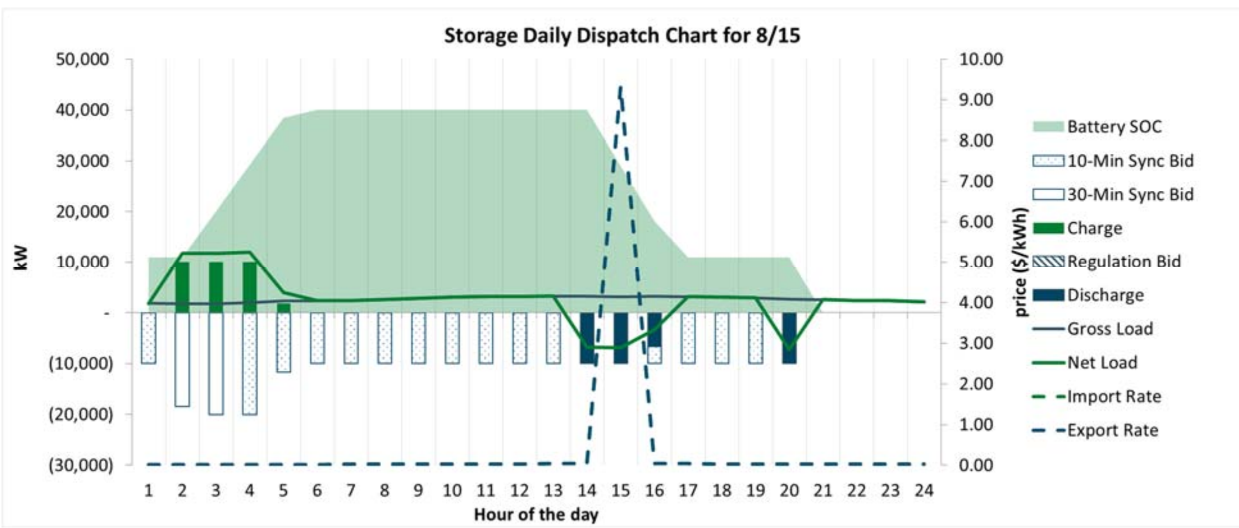


Figure 22. Storage Dispatch Chart: Bulk System During Energy Arbitrage[65]



[64] Storage sized at 10 MW, 4-hour duration.
[65] Storage sized at 10 MW, 4-hour duration.

G More Detail on the Environmental Value ("E" Value) Analysis

Energy storage systems are widely considered a key element of a decarbonized electric grid because they enable greater adoption of renewable technologies such as solar PV and wind power. While it is true that energy storage can maximize the grid value of renewable generation by minimizing curtailment and time-shifting renewable supply, energy storage's greenhouse gas (GHG) or carbon impact is highly dependent on the storage technology used and system conditions.

As described in Section 4.1.4 of the Roadmap, the three main factors affecting carbon emissions related to energy storage are:

1. The carbon emissions from the generator(s) charging the energy storage, or the marginal generator at the time of charging if charging from the grid.
2. The carbon emissions of the displaced marginal generator(s) when the energy storage discharges.
3. The "round-trip efficiency" and "parasitic" losses of energy storage, which refer to the energy losses associated with charging, discharging, and maintaining charge.

Ideally, energy storage would charge from low-carbon, low-priced generation during off-peak hours, and then discharge electricity during peak hours when marginal generation is usually more carbon-intensive and expensive. Operating the energy storage in such a manner could both be profitable and reduce carbon emissions. In the analysis performed, higher energy prices (LBMP) are generally correlated with higher intensity carbon emissions.

The analysis performed by E3 and presented in the Roadmap considers the carbon offset from energy storage as the delta between the marginal emission rate (MER) when storage charges and discharges. The MER is determined by the marginal source of generation, which varies as a function of energy demand across time and location. It is difficult to identify which power plants on the grid respond to a change in energy demand for some of the following reasons:

- <u>Hydropower on the margin:</u> In the short run, hydro emits no carbon emissions as it generates electricity from water and gravity. Measuring MERs when hydro is on the margin is not trivial – and in New York, hydro was the marginal generator during 67 percent of the time in 2016. If hydro is non-storable or the water reserves are full, then the MER of hydro is zero. The complexity comes from storable hydro, since it produces electricity based on opportunity costs. When bidding energy, storable hydro considers not only how much money it could get for producing electricity today, but also how much money it could earn if it stores water today and uses it to produce energy in the future. Therefore, when hydro is marginal based on opportunity costs, hydro is generating because prices are high, and it is likely displacing fossil fuel generators. If prices were to drop, hydro wouldn't have produced electricity but rather would have waited for a high-priced hour. A change in load would cause hydro to modify its behavior on the margin; therefore, hydro's effective MER is the emission rate of the neighboring generators in the generation supply curve (i.e., the fossil fuel generator that hydro would displace).
- <u>Non-economic fuel usage:</u> New York has a number dual-fuel power plants that don't always choose fuel based on economics; for example, reliability rules require some power plants to burn oil during winter in order to limit the electrical grid's exposure to disruptions in natural gas supply.
- <u>Congestion:</u> Congestion in power systems occurs when there is insufficient transfer capacity to meet the energy demand of all customers with the preferred (usually least cost) generation plants.

When transmission constraints are active, more than one generation unit may be marginal. This occurs because of the network nature of the energy grid, and the fact that energy flow across transmission lines follows the laws of physics. In other words, charging an energy storage asset in a congested node will affect energy flows across the entire network, and the energy for charging may be provided by more than one generator in the system. When this occurs, the MER becomes a linear combination of marginal generators whose coefficients depend on the grid architecture and its operating conditions.

- Imports: In interconnected energy systems, the marginal generation may come from a unit outside of the jurisdiction of the system operator (i.e., imports). Therefore, finding the MERs would require performing the same carbon MER analysis on neighboring jurisdictions. On top of that, system operators have different policies on data requirements and operation.
- Out of market energy dispatch: During emergency conditions or for reliability purposes, transmission or distribution system operators may call generators to produce energy outside of economic merit to provide reserves for reliability or emergency contingencies.
- Storage: Energy storage could potentially be the marginal generators in the system. When this occurs, the marginal carbon emissions will depend on the MER at the time that storage charged.

E3 analyzed historic hourly MERs of NYISO system on a zonal basis for 2015 and 2016 from a NYISO-commissioned study[66] and based on publicly available data. The key takeaways and recommended actions regarding shaping the E Value in the VDER value stack are presented in Section 4.1.4 of the Roadmap.

[66]http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg_ipptf/meeting_materials/2018-03-19/Calculation%20of%20Hourly%20MERs%20for%202017%20Customer%20Cost%20Impact%20Analysis%2020180308%20FOR%20POSTING.pdf;

H Expanded Downstate Peaker Analysis

As part of the Roadmap, E3 performed a high-level screening analysis of downstate (Zone J and Zone K) peakers to determine whether any units had characteristics that would make them potential candidates for repowering and/or replacement with energy storage systems. This analysis examined the operational profiles of these units based on 2015-17 generation data from three sources:[67]

- **NYISO Planning Documents** for 2017 NYCA Generation Facilities, which included Unit Name, Zone, Location, In-Service Date, Summer and Winter Capacity, Unit Type and Fuel types
- **EPA Air Markets Program Data** for 2015-2017, which included:
  - Unit-by-Unit hourly data for generation, operating time, CO_2, SO_2, and NO_x, emissions[68]
  - Facility-level data for Location, Owner, Operator, Unit type, Fuel types, Commercial Operation Date and Pollutant controls
- **SNL Financial (S&P Market Intelligence)** for 2015-17, which included Unit-by-unit data for Fuel Costs, Total O&M, Fixed Costs, and Heat Rates.

The analysis was done from a purely *ex post* operational screening perspective. No consideration was given to contracting and financial arrangements, nor to reliability planning or local reserve requirements that may apply to individual facilities and/or specific units. While data coverage for this analysis was not 100 percent, it did yield several useful insights.

Operational Analysis

The first step of the screening methodology was to separate peaking units into three groups based on their respective operational characteristics:

- **Group 1:** Peaking units that never run more than 4 hours per start[69]
- **Group 2:** Peaking units that average less than 4 hours per start but may run more than 4 hours[70]
- **Group 3:** Peaking units that always run more than 4 hours[71]

The analysis then compared different metrics of each group across years and looked at whether units operate at concurrent time periods. Large facilities were analyzed by aggregating their individual units into the appropriate group.

The figure below illustrates Hours per Start and Longest Start for Group 1, 2, and 3 peaking units, using 2017 data where the size of the bubbles represents the MWs of the peaking units:

[67] The data extraction methodology was as follows:
- Extract list of 2017 NYCA candidate generators which are existing peakers and steam turbines (ST) in Zones J & K
- Match units from NYISO generator data with EPA Facility data using name, in-service date, unit type, and capacity
- Extract hourly unit-level operations and emissions data from EPA dataset
- Calculate unit-by-unit: Hours of operation, # Starts, Hours of operations / start, Distribution of the duration of starts, # and % of starts with durations greater than 4 hours, Capacity factor, Age, Emission intensity
- Match unit-level S&P Market Intelligence data to determine Fuel Costs ($/MWh), Total O&M ($/MWh) and heat rates (btu/kWh)

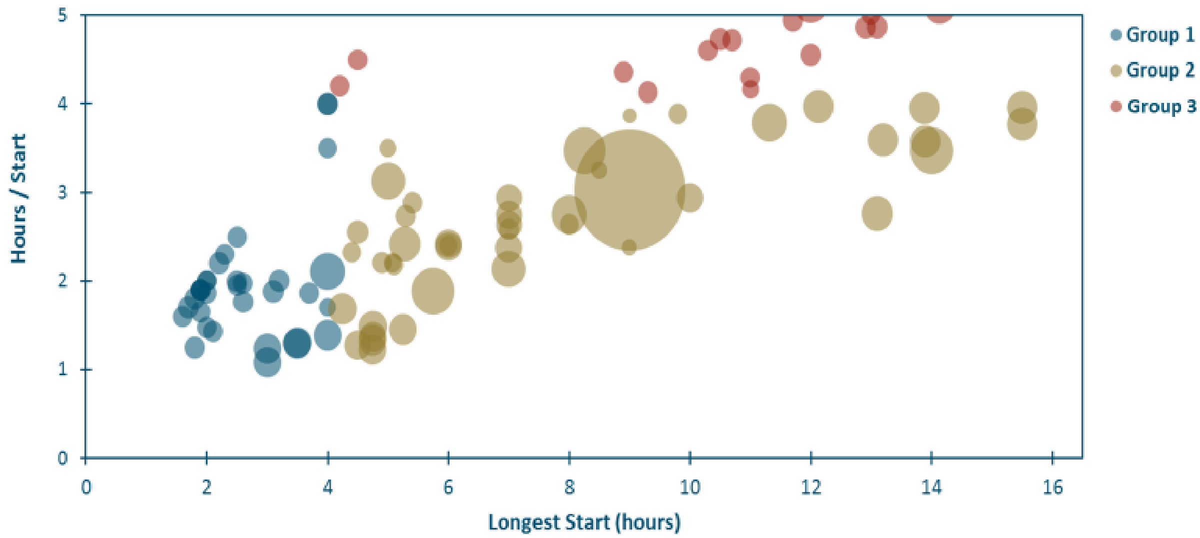
[68] Note that this dataset is incomplete: for a subset of units, operation data is only reported from April to September and does not include CO_2 or SO_2 emissions.

[69] These are units like the ones in the Gowanus and Astoria facilities.

[70] These are units like the ones in the Ravenswood, Gowanus, and Astoria facilities.

[71] These are units like the ones in the Bayonne and Narrows facilities.

Figure 23. Hours per Start and Longest Start for Group 1, 2, and 3 Peaking Units



The **average characteristics** of Group 1 and 2 peaking units, based on 2017 data, were as follows[72]:

Table 17. Average Characteristics for Group 1 and 2 Peaking Units (2017)

Group	Total MW	# of Units	Avg. Unit Age	Capacity (MW)	CF (%)	# Starts	# of Hours per start	Longest Start (hrs)	NOx Emissions (lbs/MWh)	Est. Fuel Costs ($/MWh)	Est. Total O&M ($/MWh)
1	708	34	47.5	20.8	0.2%	10.9	2.0	2.7	6.9	131.6	674.6
2	2,002	45	40.0	44.5	1.4%	43.4	2.7	7.8	5.3	88.0	227.5

Analysis showed that these characteristics vary across years, as shown in the following tables based on 2016 and 2015 data, respectively:

[72] Group 3 is not included because the focus of this analysis was Groups 1 and 2.

Table 18. Average Characteristics for Group 1 and 2 Peaking Units (2016)

Group	Total MW	# of Units	Avg. Unit Age	Capacity (MW)	CF (%)	# Starts	# of Hours per start	Longest Start (hrs)	NOx Emissions (lbs/MWh)	Est. Fuel Costs ($/MWh)	Est. Total O&M ($/MWh)
1	301	18	47.3	16.7	0.2%	5.1	1.8	2.7	8.0	191.1	1151.2
2	1,539	55	45.3	28.0	1.2%	33.3	3.0	9.6	5.6	88.5	278.4

Table 19. Average Characteristics for Group 1 and 2 Peaking Units (2015)

Group	Total MW	# of Units	Avg. Unit Age	Capacity (MW)	CF (%)	# Starts	# of Hours per start	Longest Start (hrs)	NOx Emissions (lbs/MWh)	Est. Fuel Costs ($/MWh)	Est. Total O&M ($/MWh)
1	388	21	47.3	18.5	0.1%	4.0	1.7	2.2	7.1	198.2	940.4
2	2,089	55	45.4	38.0	0.9%	33.9	2.6	8.8	6.3	93.3	338.1

Overall **fleet characteristics** for Groups 1, 2, and 3 peaking units were calculated as follows (note that NO_x, CO_2 and SO_2 emissions are weighted average emissions rates):

Table 20. Downstate Peaking Units: Overall Characteristics Based on 2017 Data[73]

Group	# of Units	Age	Total Capacity (MW)	Avg Unit Size (MW)	CF (%)	# of Hours per start	Avg Longest Start (hrs)	NOx Emissions (lbs/MWh)	CO2 Emissions (tons/MWh)	SO2 Emissions (lbs/MWh)
1	34	47.5	708	20.8	0.2%	2.0	2.7	4.594	0.587	0.083
2	45	40.0	2,002	44.5	1.4%	2.7	7.8	2.474	0.659	0.017
3	47	29.3	1,858	39.5	8.6%	5.6	19.9	0.627	0.572	0.006

Similarly, **operation data**[74] from Groups 1, 2, and 3 units were as follows:

---

[73] 2017 is not necessarily a representative year from a meteorology perspective and the fleet characteristics may change year to year.

[74] This was based on hourly data to the extent possible.

Table 21. Downstate Peaking Units: Operation Data

Group	Summer Gen (MWh)	Summer NOx (lbs)	Summer CO2* (tons)	Summer SO2 (lbs)	Total Gen** (MWh)	Total NOx** (lbs)	Total CO2* (tons)	Total SO2* (lbs)
1	10,270	47,798	6,076	309	18,922	86,924	11,113	1,574
2	144,149	302,576	95,690	1,310	214,923	531,664	141,754	3,751
3	1,138,329	693,723	661,713	6,283	1,777,062	1,114,513	1,015,620	9,855

** CO_2 & SO_2 values were estimated with the group average emission factor for units that do not report data*

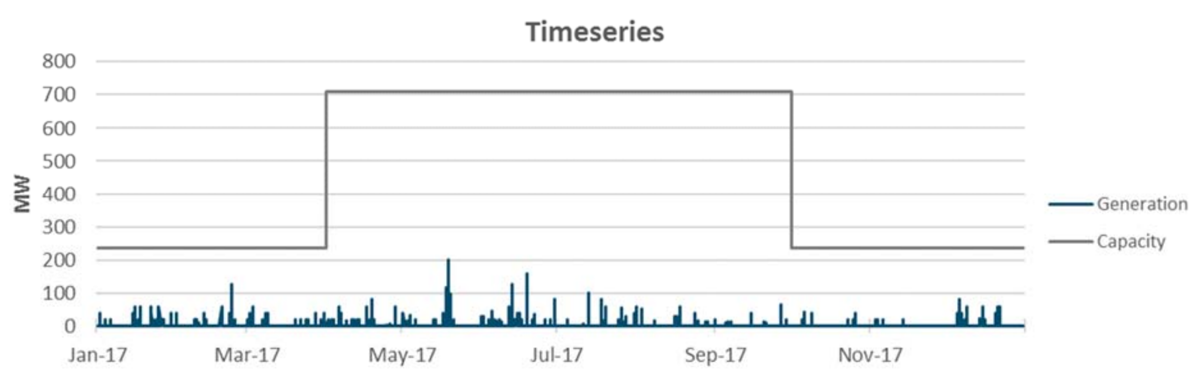
*** For units that do not report winter data, totals were estimated using summer capacity factor*

Three important **caveats** related to limitations in the EPA dataset must be made. Several units in this dataset – predominantly Group 1 units, characterized by small units with very low capacity factors that typically burn oil in the winter – only report data for the SIP NOx program. This program only includes data from April 1 through September 30 for generation and NOx emissions, and does not include data for CO_2 or SO_2 emissions. Consequently:

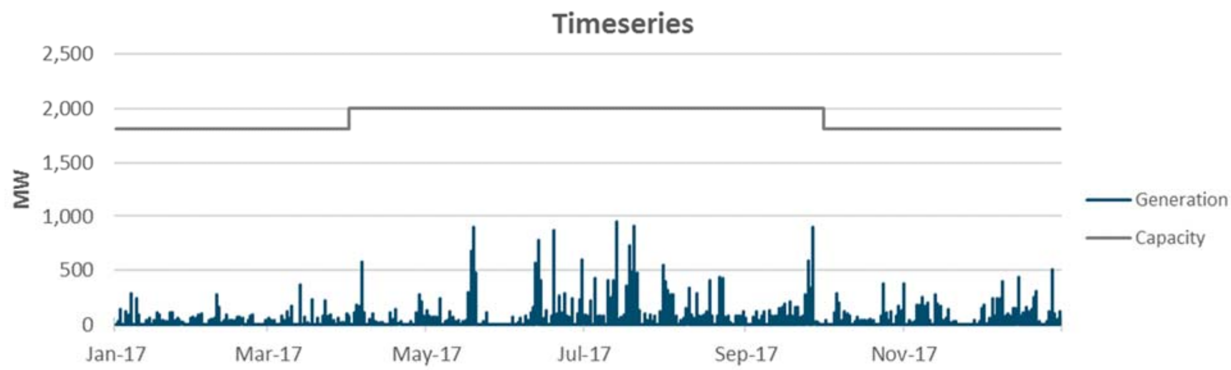
- **Group 1 units' emission rates and total emissions may be understated**. This is due to understating the amount or relative share of oil burnt to natural gas given that oil is more carbon- and SO_2-intensive than natural gas.
- **Group 1 units' total generation may be slightly overestimated** since peakers seem to run slightly more during the summer than during the winter.
- **There is substantially more uncertainty in the estimates of Group 1 fleet characteristics** (e.g., hours/start, capacity factors, emission rates, etc.) relative to Group 2.

Analysis showed that peaking units that may be candidates for energy storage hybridization, replacement, or repowering (those in Groups 1 and 2) did not seem to operate near capacity at any point in 2017. They do, however, appear to have operated concurrently during a few scarcity periods, particularly in the summer months and in December:

Group 1



Group 2



As shown in the following graphic, the locations of Group 1 and Group 2 peaking units (shown as dropped pins) are highly correlated with Environmental Justice (EJ) areas (highlighted in purple), particularly near New York City:

Finally, the analysis also developed **high-level 2017 revenue estimates** for peaker units in Groups 1, 2, and 3. The methodology here involved developing NYISO market revenue estimates for peaker fleets, and then utilizing publicly available monthly ICAP prices and LBMPs for individual peakers. Note that this analysis does not account for uplift payments or other payments (e.g., startup costs) for units operating for local reliability in an out of merit order dispatch. The 2017 economics of peaking units were found to be as follows.

Table 22. Downstate Peaking Units: Revenue Estimates (2017)

Group	Zone	ICAP Revenues[1]	Energy Revenues[2]	Fuel O&M[2]	Total O&M[2]	Profits[2]	Profits[3] ($/kW-yr)
1	J	$ 56,930,557	$ 1,329,050	$ 1,167,011	$ 4,466,504	$ 53,793,102	**$ 83.49**
	K	$ 2,690,250	$ 80,215	$ 192,383	$ 608,174	$ 2,162,291	**$ 34.05**
2	J	$ 70,283,942	$ 10,186,056	$ 5,530,799	$ 13,444,249	$ 67,025,749	**$ 83.28**
	K	$ 50,660,202	$ 7,797,749	$ 6,921,433	$ 13,065,499	$ 45,392,452	**$ 37.90**
3	J	$ 92,971,144	$ 53,086,648	$ 35,554,043	$ 45,384,867	$ 100,672,925	**$ 92.03**
	K	$ 32,127,144	$ 41,377,071	$ 28,729,124	$ 35,158,194	$ 38,346,021	**$ 50.19**

[1] *ICAP revenues assumes that all the summer and winter capacity is under contract at average price*
[2] *For units that do not report Winter data, totals are estimated using Summer capacity factor*
[3] *Profits = (ICAP + Energy Revenues) – Total O&M*

The key takeaways from this analysis are summarized in Section 4.6 of the Roadmap.

This analysis did not consider local reliability requirements where these facilities may be considered for meeting contingency needs. The Roadmap recommendations include conducting a series of Reliability and Operational Assessment Studies looking at the equivalent level of “clean resources” that could provide the same level of reliability as the existing peaker units, considering current operational practices and explicitly factoring in new potential operational paradigms.

<u>Net CONE Analysis</u>

The net cost of new entry (CONE) between a new battery and a conventional unit is expected to cross over as early as the 2022-2023 timeframe for a 4-hour battery and later for longer-duration batteries.

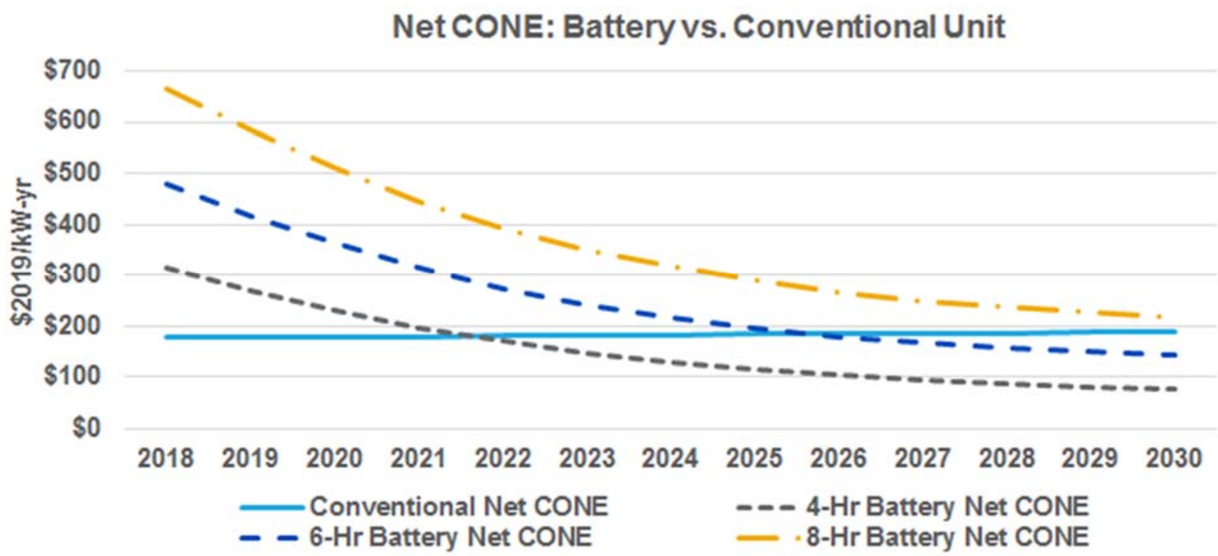


Table 23. Net CONE Assumptions for a New Lithium-ion Battery vs. a Conventional Unit (Based on NYISO 2017 ICAP Demand Curve Reset Assumptions)[75]

Installed Battery Cost ($/kWh)	**$563**	$/kWh (2019 Forecast)
Battery Duration (hours)	**4**	Hours
Installed Battery Cost ($/kW)	$2,250	$/kW
Levelized Fixed Charge Rate (%)	**17.59%**	
Gross Battery CONE for Wholesale Zone J	$395.80	$/kW-yr
Wholesale Energy and AS Market Revenues	$82.00	$/kW-yr
Net Battery CONE for Wholesale Zone J	**$313.80**	$/kW-yr
Installed Siemens SGT6-5000F5 Cost	**$1,340**	$/kW
Fixed O&M + Insurance	$37.30	$/kW-yr
Levelized Fixed Charge Rate	**13.12%**	
Gross Siemens SGT6-5000F5 CONE for Wholesale Zone J	$213.06	$/kW-yr
Wholesale Energy and AS Market Revenues	$35.91	$/kW-yr
Net Siemens SGT6-5000F5 CONE for Wholesale Zone J	**$177.15**	$/kW-yr
Net Conventional CONE escalator (real)	**0.5%**	

[75] http://www.nyiso.com/public/markets_operations/market_data/icap/index.jsp

I Acronym List

AHJ	Authorities Having Jurisdiction
AMI	Advanced Metering Infrastructure
ARRA	American Recovery and Reinvestment Act
AS	Ancillary Services
BCA	Benefit Cost Analysis
BICOS	Breakeven Installed Cost of Storage
BQDM	Brooklyn-Queens Demand Management Program
BTM	Behind the Meter
BTU	British Thermal Unit
C-PACE	Commercial Property Assessed Clean Energy
CAES	Compressed Air Energy Storage
CARIS	Congestion Assessment and Resource Integration Study
CCA	Community Choice Aggregation
CDG	Community Distributed Generation
CHG&E	Central Hudson Gas & Electric
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CSRP	Commercial System Load Relief
DEC	New York State Department of Environmental Conservation
DER	Distributed Energy Resources
DG	Distributed Generation
DLM	Dynamic Load Management
DLRP	Distribution Load Relief Program
DMP	Demand Management Program
DPS	New York State Department of Public Service
DR	Demand Response
DRV	Demand Reduction Value
DSIP	Distributed System Implementation Plan
EAM	Earnings Adjustment Mechanism
EIC	New York State Energy Improvement Corporation
EJ	Environmental Justice
ELR	Energy Limited Resource
EPA	U.S. Environmental Protection Agency
ESCO	Energy Service Company
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
FOM	Front of Meter
G&T	Generation & Transmission
GEIS	Generic Environmental Impact Statement
GRC	General Rate Case
GW	Gigawatt

GWh	Gigawatt-hour
ICAP	Installed Capacity
IOU	Investor Owned Utility
IPPTF	Integrating Public Policy Task Force
IPWG	Interconnection Policy Working Group
IRR	Internal Rate of Return
ITC	Investment Tax Credit
ITWG	Interconnection Technical Working Group
kW	Kilowatt
kWh	Kilowatt-hour
LBMP	Locational Based Marginal Pricing
LBNL	Lawrence Berkeley National Laboratory
LCOS	Levelized Cost of Storage
LESR	Limited Energy Storage Resource
LIPA	Long Island Power Authority
LL84	Local Law 84
LSR	Large Scale Renewables
LSRV	Locational System Relief Value
MER	Marginal Emission Rate
MHP	Mandatory Hourly Price
MILP	Mixed Integer Linear Programming
MW	Megawatt
MWh	Megawatt-hour
NAICS	North American Industry Classification System
NO_x	Nitrogen Oxides
NPV	Net Present Value
NWA	Non-Wires Alternative
NWA+	Expanded Non-Wires Alternative
NY-BEST	New York Battery Energy Storage Technology Consortium
NYCA	New York Control Area
NYCEEC	New York City Energy Efficiency Corporation
NYGB	New York Green Bank
NYISO	New York Independent System Operator
NYPA	New York Power Authority
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations & Maintenance
PACE	Property Assessed Clean Energy
PILOT	Payment In Lieu of Taxes
PLUTO	New York City Primary Land Use Tax Lot Output
PON	Program Opportunity Notices
PSC	New York State Public Service Commission
PSEG	Public Service Enterprise Group
PV	Photovoltaic

REC	Renewable Energy Credit
RESTORE	E3’s Energy Storage Dispatch Model
REV	Reforming the Energy Vision
RFI	Request for Information
RFP	Request for Proposal
SAPA	State Administrative Procedures Act
SCC	Social Cost of Carbon
SCR	Special Case Resource
SHR	Smart Home Rate
SMES	Superconducting Magnetic Energy Storage
SO_2	Sulfur Dioxide
SO_x	Sulfur Oxides
T&D	Transmission and Distribution
TOU	Time of Use
UER	Utility Energy Registry
VDER	Value of Distributed Energy Resources
VoLL	Value of Lost Load
WACC	Weighted Average Cost of Capital
ZEC	Zero Emission Credit

J General Glossary of Terms

Avoided cost

The cost of generating power that a utility avoids by purchasing the same amount of power from another source. A commonly used form consists of a forecast of future avoided costs, known as a long range avoided cost (LRAC) projections.

Base load unit

A generating unit operated close to its maximum output all the time it is available for service; generally, units whose energy costs are among the lowest on the system.

British Thermal Unit (BTU)

The amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. This unit provides a common denominator for quantifying all types of energy on an equivalent energy content basis.

Capacity

The load for which a generating unit is rated by its manufacturer. For an electric system, the total load rating for all generating units.

Capacity factor

The ratio of actual output for a specific time period to the maximum output possible during that period.

Cost of capital

The composite cost to the utility of interest on debt, dividends on preferred stock, and earnings requirements of common stockholders, as calculated by the actual or projected costs of each times the percentage each represents of the total capital structure.

Customer charge

The charge to a customer that is designed to compensate the utility for the costs it incurs as a result of that customer's subscription to utility service, irrespective of the customer's eventual demand or energy use.

Demand (or Load)

The amount of electricity that must be generated to meet the needs of all customers at a certain point in time.

Demand charge

The charge to a customer based on the maximum demand generally denoted in kilowatts its use of electricity places on the system.

Demand Response (DR)

Temporarily reducing electricity usage in response to a request from the system operator to do so, typically to maintain system reliability, and typically in exchange for a financial incentive.

Demand Side Management (DSM)

The planning, executing and monitoring of utility activities designed to help customers use electricity more efficiently.

Depreciation

The effect of aging on the original cost of utility facilities, or the charge used to recover over time the capital originally invested in the facilities.

Direct Load Control

DSM programs where the utility pays the customer to install a switch (typically radio operated), which allows the utility to control the customers' equipment (e.g., air conditioners, water heaters, pool pumps, etc.) as a way of reducing demand during peak periods.

Discount rate

A measure, usually expressed in annual percentages, of the change in the value of money from one time period to another. Nominal discount rate includes anticipation price inflation; real discount rate does not.

Distributed Generation

Small electric-generating facilities fueled with renewable or nonrenewable resources located near the end consumer, such as solar panels installed on residential buildings, fuel cells located in office buildings, or fossil-fuel-burning back-up assets.

Distribution

The delivery of energy to end-users or customers. The distribution component of New York State's electric system generally uses power lines to carry electric power from the transmission component to the locations of end-use consumers.

Distribution System Platform Providers

The distribution system platform (DSP) providers will modernize electric distribution systems to create a flexible platform for new energy products and services, to improve overall system efficiency and to better serve customer needs. The DSP providers will incorporate distributed energy resources into planning and operations to achieve the optimal means for meeting customer reliability needs.

Earnings Adjustment Mechanism (EAM)

An outcome-based incentive mechanism designed to create new performance expectations to meet certain objectives under New York's Reforming the Energy Vision (REV) initiative.

Energy efficiency

Any technology or activity that results in using less energy to provide the same level of service, work, or comfort.

Energy Service Company (ESCO)

A non-utility business that provides gas or electric commodity or that installs energy efficient and other demand side management measures in facilities.

Environmental externalities

The environmental costs to society of electricity generation that are not reflected in the utility's cost of producing electricity or the price paid by customers to consume electricity.

Environmental Justice

The fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.

Fixed cost

Costs that do not vary in relation to the amount of service provided.

Fossil fuel

Fuels derived from organic material formed by the compression in the Earth's crust of ancient plants and animals over millions of years. The most common fossil fuels are petroleum products, coal, and natural gas.

Generation

Generation refers to both the mechanical units and the process of producing electricity by transforming other types of energy, including fossil fuels, hydro, nuclear, wind, photovoltaic, etc. Generation is commonly expressed in kilowatt-hours (kWh) or megawatt-hours (MWh).

Green power

Energy produced from renewable or non-polluting and non-hazardous technologies.

Greenhouse gas (GHG)

A gas in the atmosphere that absorbs or emits radiation within the thermal infrared range. GHGs prevent radiant energy from leaving the Earth's atmosphere or trap the heat of the sun, producing the greenhouse or warming effect. The primary GHGs include carbon dioxide, methane, nitrous oxide, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride.

Heat rate

A measure of generating plant heat efficiency, generally expressed in Btu per net kilowatt-hour.

Incremental cost

The additional cost of producing another unit; sometimes used as a more measurable proxy for marginal cost.

Independent Power Producer (IPP)

A company other than a utility that generates electricity. Also referred to as a non-utility generator (NUG) or non-utility supplier.

Independent System Operator (ISO)

An entity that monitors the reliability of the bulk power system and coordinates the supply of electricity.

Investment tax credit (ITC)

A credit against the Federal income tax liability for the capital cost of purchasing new equipment; granted by Congress in the 1970s to encourage investment.

Kilowatt-hour (kWh)

A measure of electricity defined as a unit of work or energy, measured as 1 kilowatt (1,000 watts) of power expended for 1 hour. One kWh is equivalent to 3,412 British thermal units (Btu).

Least-cost planning

The balancing of supply-side and demand-side alternatives to meet energy needs at least cost (often called Integrated Resource Planning).

Load factor

The ratio of the amount of electricity used during a specific time period to the maximum possible use during that period.

Load management

Utility activities designed to influence the timing and amount of electricity that customers may use.

Load pocket

An area served by local generators when the existing transmission system cannot import sufficient power to meet local demand.

Load shifting

A type of load management that shifts use from peak to off-peak periods, such as using storage water heating and space heating.

Local Distribution Company (LDC)

The utility company that provides the distribution, customer and energy services for natural gas and electricity.

Marginal cost

The cost incurred in producing or the cost saved by not producing an additional unit of good.

Megawatt (MW)

A unit of electrical power equal to 1,000 kilowatts or one million watts.

Net Metering, Net Energy Metering (NEM), or Shared Renewables

Allowing a customer's electric meter to measure both the reverse and forward flow of electricity, allowing the meter to register when a customer is producing more energy on-site than it is using (which will cause the meter to reverse), as well as when a customer is producing less energy than it is using (which will cause the meter to move forward). The combined effect of the reverse and forward flows results in net metering.

Net lost revenues

Gross revenue losses associated with selling less electricity as a result of DSM programs minus the production costs avoided by the reduced sales. New York utilities are allowed to recover net lost revenues under the current DSM incentive plans.

Net savings

Total energy savings resulting from implementing a demand-side program, such as gross change in energy usage minus savings attributable to free riders and/or a change in weather, demographics and consumer behavior.

Off-peak

A period of time when there is a low demand for electricity on a utility's generation system.

On-peak

A period of time when there is a high demand for electricity on a utility's generation system.

Peaking unit, or peaker

A generating unit used to meet the portion of peak load that cannot be met by base load units. Generally, these are higher energy cost units, such as gas turbines.

Present value

The current value of money that will be spent or collected in the future; the determination of present value adjusts for the difference over time resulting from inflation and interest rates.

Real-time pricing

Prices determined according to conditions existing at the time of pricing (or no more than a day in advance of pricing).

Reforming the Energy Vision (REV)

Reforming the Energy Vision (REV) is Governor Cuomo's strategy to build a clean, resilient, and more affordable energy system, while actively spurring energy innovation, bringing new investments into the State, and improving consumer choice.

Regional Greenhouse Gas Initiative (RGGI)

A mandatory, market-based effort to reduce greenhouse gas emissions in nine Northeastern and Mid-Atlantic States, including New York. It is implemented in New York by DEC and NYSERDA.

Reliability

Bulk electric system (i.e., generation and transmission) reliability consists of a series of very specific engineering-based metrics that measure both resource adequacy and transmission operating reliability. Resource adequacy measures the degree to which system resources are sufficient to be able to meet customer load when and where needed. Transmission operating reliability measures the ability of the delivery system to get the power to the load and its ability to withstand various contingencies such as generators or transmission lines being out of service without dire consequences. Electricity distribution (i.e., service) reliability is measured by utility- led data on frequency and duration of service interruptions.

Renewable energy

Energy derived from sources that are capable of being continuously restored by natural or other means, or are so large as to be usable for centuries without significant depletion, and include but are not limited to solar, wind, plant and forest products, organic wastes, tidal, hydropower, and geothermal.

Repowering

The retirement of a power plant and the reconstruction of a new, cleaner, and more efficient plant on the same property.

Reserve

The availability of additional generation. Installed reserve is the amount of existing generation that is higher than needed to meet a forecasted peak load. Operating reserve is the amount of generation that may be used to offset a loss of supply to maintain a power system.

Resiliency

Ability of the energy system to reduce the impact and duration of disruptive events. Resiliency encompasses the capability to anticipate, prepare for, respond to, and recover from significant multi-hazard threats with minimum damage to the energy system, environment, economy, and social well-being.

Smart Grid

According to the U.S. Department of Energy (DOE), smart grid generally refers to “a class of technology people are using to bring utility electricity delivery systems into the 21st century, using computer-based remote control and automation. These systems are made possible by two-way communication technology and computer processing that has been used for decades in other industries.” Smart grid technology can enable system operators to more quickly identify the location and cause of an outage as well as enable customers to adjust their energy usage patterns in response to pricing information from the grid.

Solar photovoltaic

Also known as PV or solar electric, this technology directly converts the energy radiated by the sun as electromagnetic waves into electricity by means of solar panels.

Substation

The location for equipment that makes up the interface from transmission to distribution. This includes transformers and various protection devices.

Time of use (TOU) rates

Rates that are designed to reflect changes in a local distribution company’s cost of providing service that change by season or time of day.

Transmission

The transportation of electric energy in bulk at high voltages, generally from a generating unit to a substation or for transfer between utility systems.

Wind energy

A renewable source of energy used to turn turbines to generate electricity.

Zero Net Energy Building

A building where the total amount of energy used on an annual basis is roughly equal to the amount of renewable energy created on the site.

K Acelerex Study

NYSERDA/DPS Energy Storage Study Results

May 2018

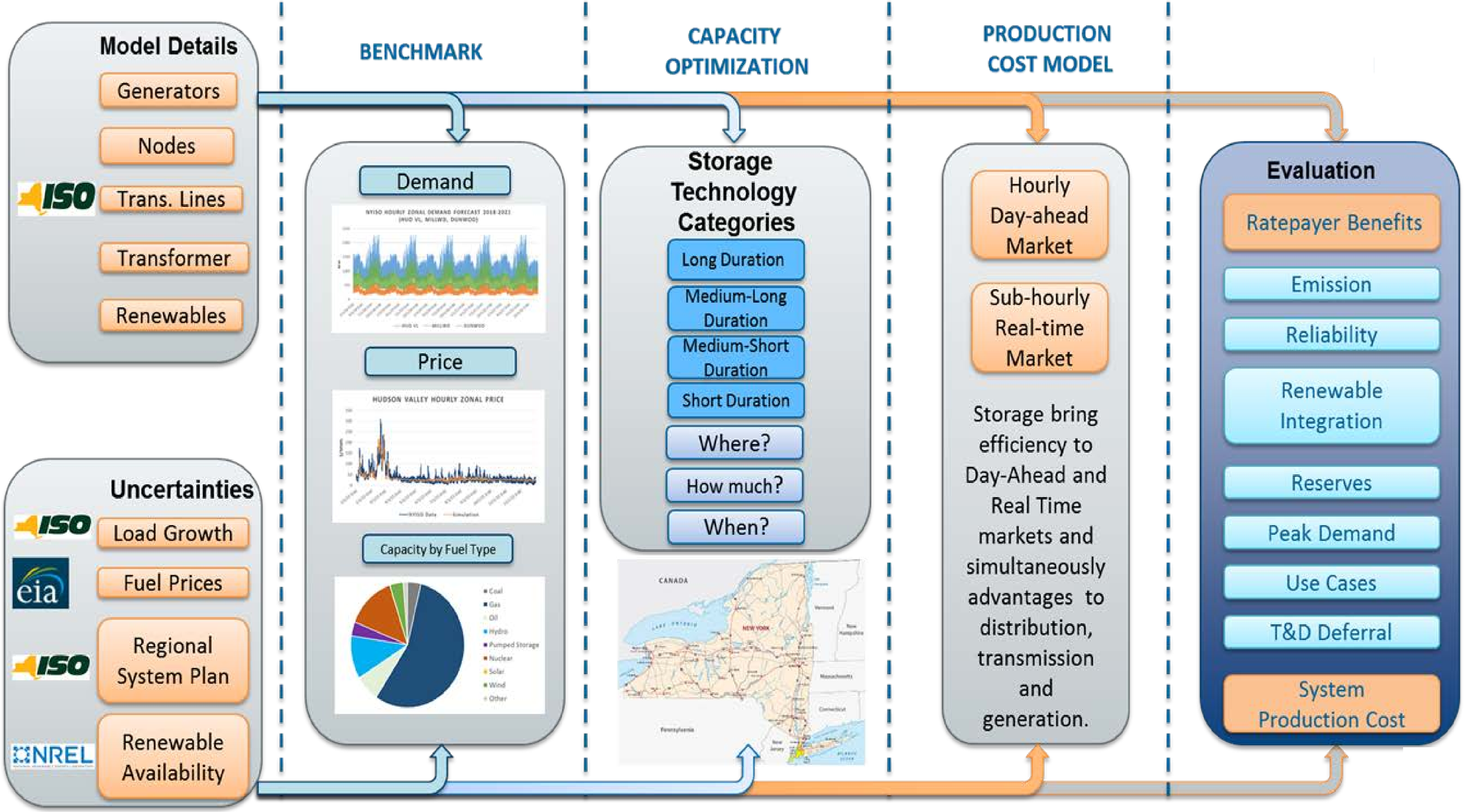
acelerex

Storage Study Scope

Determine ranges of energy storage that could result in net positive benefit to ratepayers, compared to alternatives, in meeting electric system needs including installed capacity, transmission/sub-transmission, and distribution needs, that arise under various scenarios, sensitivities, and time horizons (2020, 2025, 2030).

Identify performance specifications (MW, MWh) of the deployed storage as well as costs and benefits consistent with Benefit Cost Analysis framework.

Energy Storage Study Methodology



Four primary steps for each scenario in the study:

1) Develop assumptions, Benchmark inputs
2) Run Capacity Optimization Model
3) Run Production Cost Model
4) Utilize model outputs to calculate Benefit-Cost Analysis

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Capacity Optimization Model

- Model builds out least-cost capacity mix to meet Base Case load and comply with system constraints (2020 – 2030)
- Added four new Energy Storage Asset Types to the model according to the energy, power, and cost characteristics of the four duration buckets (refer to slide 10)
  - This allowed the model to choose storage among other traditional capacity options
- Optimization results show the type, quantity, zone, and year of all capacity needed to reach least-cost system through time frame

Production Cost Model

- Zonal buildout from the Capacity Optimization Model is fed into the Production Cost Model to determine the hourly operation of the system
- Model then calculates variable costs, fuel use, emissions, etc., of the capacity buildout in the hourly dispatch simulation
- Outputs allow for a full accounting of the Benefits and Costs of the Storage deployed by the model

Generation and Transmission Mapping

Transmission Line Voltage Levels

NYISO

- Internal Lines: 4933
- Transformers: 1741
- Interregional lines: 54

Voltage	NYISO Lines
<=13.8KV	57
18KV	0
23KV	150
27KV	7
46KV	2548
69KV	387
115KV	1129
138KV	420
215KV	1
≥345KV	212

Enforced in production cost model results

Reflected in capacity optimization results

The analysis assumes most, if not all, storage will be placed within sub-transmission and distribution networks in order to capture maximum operational benefits. For modeling purposes, all storage deployed behind a single node is aggregated by type (duration bucket) and operated as a single resource in the model. For example, if 25 MW of 4-hour duration storage is deployed at a node, and 25 more MW of 4-hour duration are deployed at the same node the following year, the model will operate as if there is a single 50MW 4-hour storage device at that node. Also, storage deployed through the Capacity Optimizer was deployed to specific nodes in the Production Cost model by giving preference to the highest peak energy nodes within a zone.

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Base Case inputs

- Study examined electric system needs that storage is best positioned to address as we reach 50% renewable generation and 40% GHG reduction.
- Electric system mapping in the model was largely limited to the transmission, generation and sub-transmission system and so distribution system needs that could arise were not fully examined.
- The “Base Case” build included achieving 50% renewables, reducing GHG emissions by 40%, Indian Point closing by 2021, and transmission upgrades included in the NYISO’s 2022 Power Flow which does not include the proposed Champlain Hudson 1,000 MW HVDC line. These inputs are detailed on slide 8.

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Base Case inputs

Inputs and Assumptions	
Clean Energy Standard	75,000 GWh total comprised of: • *Existing renewables of 43,300 GWh:* - 35,800 GWh hydro (28,000 in-state hydro and 8,000 imported hydro) - 3,800 GWh land-based wind (using a 30% capacity factor) - 700 GWh solar PV (using 13.8% capacity factor) - 3,000 GWh biomass, biogas, and solid waste • *New renewables energy of 32,216 GWh in 2030:* - 1,939 GWh in-state hydro - 9,589 GWh imported hydro - 15,746 GWh wind (1.5 GW onshore and 2.4 GW offshore w/30% and 40% capacity factors) - 4,685 GWh PV using a 13.8% capacity factor (898 MW utility scale and 3GW BTM) - 257 GWh biomass
2030 Load	Net 150,000 GWH (185,600 GWH from Clean Energy Standard Order less 35,600 GWH of energy efficiency, includes 8,600 GWH of electric vehicle charging/heat pump load)
In-State Pumped Hydro	Business as usual from historical usage profiles
Existing generation	All existing generators continue to operate; all coal is phased out by 2020; 1,200 MW of demand response is available throughout the timeframe.
Indian Point	Unit 1 closes by April 2020 and Unit 2 closes by April 2021
Natural Gas Prices	Current NYISO natural gas price forecast
Transmission Representation	NYISO 2022 Power Flow Base Case

This reflects one potential scenario for reaching 50% renewable generation

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Energy Storage Study Input Data Sources

Category	Current System	Forecast
Generation	NYISO 2017 Load & Capacity Report	NYISO 2017 Load & Capacity Report
Demand	NYISO Markets & Operations Data	NYSERDA Demand and Energy Forecast Spreadsheet and NYISO 2002 Demand Profile Assumption
Energy Efficiency		NYSERDA Demand and Energy Forecast Spreadsheet
Behind-the-meter Distributed Energy Resources		NY Sun Forecast from NYSERDA
Wind	NYISO 2017 Load & Capacity Report	CES Standard
Solar	NYISO 2017 Load & Capacity Report	CES Standard
Hydro Energy	EIA	CES Standard
Hydro and Land-based Wind Imports		CES Standard
Proposed Generator Additions		NYISO Gold Book
Deactivated Generator		NYISO Gold Book and NYSERDA Base Case Assumptions
Regulation Requirement	NYISO Regulation Requirements	NYISO Regulation Requirements
Reserve Requirement	NYISO Locational Reserve Requirement	NYISO Locational Reserve Requirement
New Capacity Costs		AEO 2017
Storage Costs	Blended costs from multiple market sources	Blended costs from multiple market sources
Emissions Prices	2017 RGGI CO2 Allowance Auction Report	2017 CARIS Emissions Price Forecast
Emissions	EPA Emission Database	EPA Emission Database
Market & Operational Data:	NYISO Markets & Operations Data	Acelerex Simulations
Interfaces Exchanges	NYISO Markets & Operations Data	NYISO Markets & Operations Data

Energy Storage Technologies and Cost Declines

Long duration (6+ hours)	**A blended set of representative technologies and costs was included in the model within "buckets" of durations.** • Li-ion, flow batteries, thermal storage, sodium based, emerging battery chemistries such as metal based, pumped hydro, compressed air storage • *Cost decreases 11% annually until 2021, then declines decrease linearly until reaching 3%/year in 2029*
Medium Long duration (4 hours)	• Li-ion, flow batteries, thermal storage, advanced lead acid, sodium based • *Cost decreases 11% annually until 2021, then declines decrease linearly until reaching 3%/year in 2029*
Medium Short (2 hours)	• Li-ion, advanced lead acid • *Cost decreases 10% annually until 2021, then declines decrease linearly until reaching 3% annual declines in 2029*
Short duration (30 mins)	• Li-ion, flywheels, ultracapacitors • *Cost decrease 10% annually until 2021, then declines decrease linearly until reaching 3% annual declines in 2029*

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Energy Storage Technologies and Cost Declines

Duration and Installed Cost	2018	2020	2025	2030
Long (6 hrs)				
per kW	$2,550	$2,020	$1,266	$1,022
per kWh	$425	$337	$211	$170
Medium long (4 hrs)				
per kW	$1,800	$1,426	$894	$722
per kWh	$450	$356	$223	$180
Medium short (2 hrs)				
per kW	$1,200	$972	$632	$514
per kWh	$600	$486	$316	$257
Short (half hour)				
per kW	$700	$569	$370	$301
per kWh	$1,400	$1,134	$737	$599

Blended cost of technologies. Cost and forecast data examined from Lazard Levelized Cost of Storage 2017, GTM Research, Bloomberg, Navigant Research and storage developers

All costs are in 2018 $ and reflect front-of-meter installed cost including a basic estimate of land lease cost for a large bulk system and interconnection. Added a 1.25 multiplier for NYC (Zone J) and 1.1 multiplier for Long Island (Zone K) installations. Local land costs, especially in NYC, can vary widely.

Due to limited mapping at the distribution circuit level, this analysis did not place storage behind a retail customer's meter. For purposes of calculating a customer sited installed cost, a 50% multiplier is suggested.

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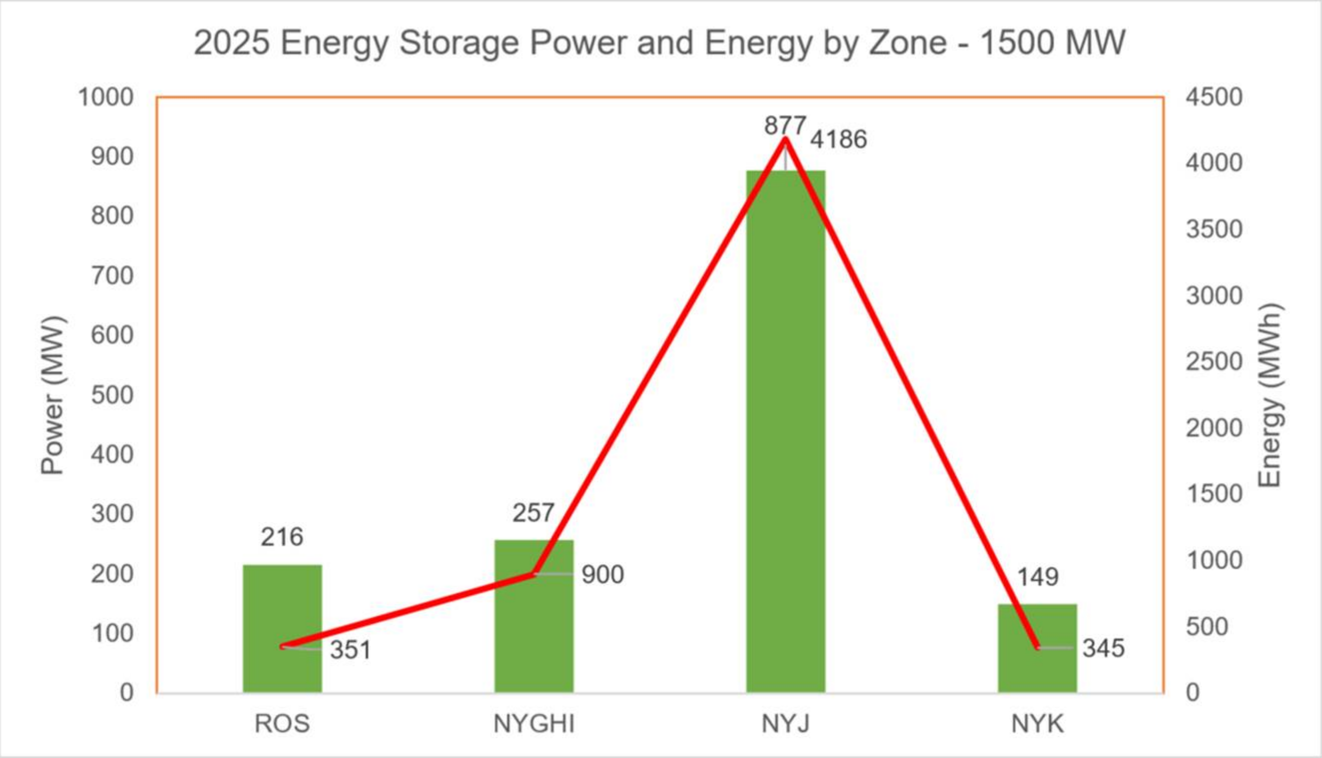
Base Case

Energy Storage 1,500 MW Analysis for 2025



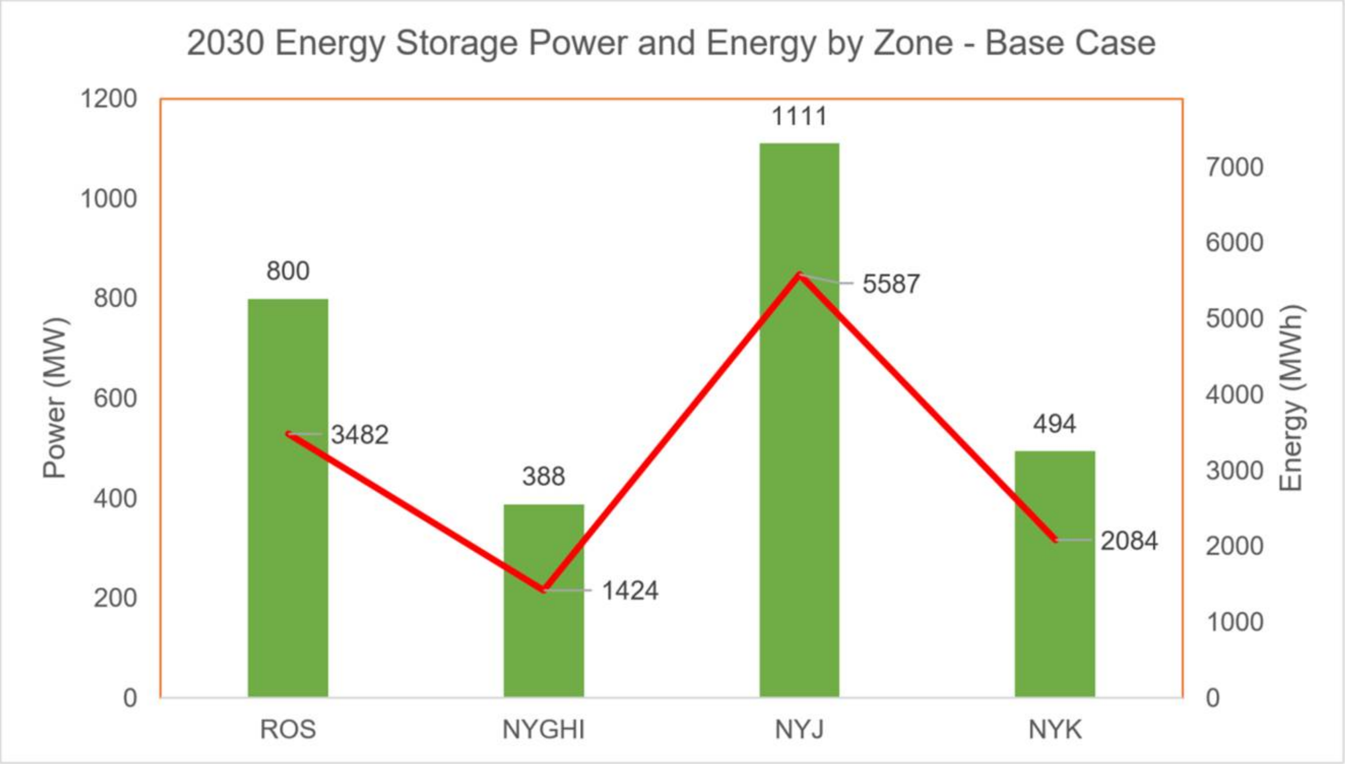
Energy Storage Buckets

Duration	MW	MWh
Long (6 hrs)	633	3,795
Medium Long (2-4hr)	242	970
Medium Short (1-2hr)	470	940
Short (30 mins)	155	78
Total	1,500	5,783

- Shown is the Governor's 1,500 MW storage target allocated by the model by zone (all upstate and western New York zones are included in "ROS," rest of state).
- This is not intended to show allocation of target deployment by utility.
- MW (power rating) is the green bar and MWh (duration) is the red line.

Preliminary Base Case Results

Energy Storage Sizing Analysis for 2030



Energy Storage Buckets

Duration	MW	MWh
Long (6 hrs)	1,447	8,682
Medium Long (4 hrs)	714	2,856
Medium Short (2 hrs)	467	934
Short (30 mins)	154	77
Total	2,795	12,557

By 2030, nearly 2,800 MW of storage is deployed by the model; 80% of the deployments between 2025 and 2030 occur outside New York City.

Base Case Outputs

Total Resource Cost-Style Lifetime BCA

The Benefit-Cost Analysis was calculated over the entire installed life of the storage assets which was assumed to be 10 years. For example, a storage project deployed on January 1, 2025 would be considered in the BCA through December 31, 2034.

Description of Benefits and Costs

- Ancillary Services: Storage MW or MWH x AS market price; storage participation was capped at 25% of total AS market in the model for conservativeness; this level could increase
- Capacity Value: uses a 4-hour capacity requirement equivalent; 4-hour equivalent Storage MW x Capacity price (by zone by year); 4+ hour duration storage gets full capacity credit, below 4-hour gets fractional credits; storage was limited to providing 10% of total in zonal capacity again for conservativeness; by 2030 the model started to come up against this limit in certain zones
- Distribution Savings: Avoided Distribution Infrastructure (Storage MW x DRV value from utility VDER tariffs). Reflects the actual DRV by utility (no LSRV was included). Only 4+ hour duration storage captured this benefit in the model.
- FOM: Difference in fixed operations and maintenance costs on the system.
- Gen Cost Savings: Difference in Total Cost to Generate required Energy, including fuel, VOM, RGGI compliance cost (Base Case Total Generation Cost – Storage Case Total Generation Cost)
- Avoided CO2 is valued at Societal Cost of Carbon less the RGGI price.
- Storage Costs: Installed cost net of an average 20% accelerated federal tax benefit. Variable Operations and Maintenance costs were estimated at $15-$20/kW/year depending on the duration and these costs along with charging cost is netted into the “Gen Cost Savings” benefit.
- 7% discount rate used and 10 year average asset life. No financing costs are included.

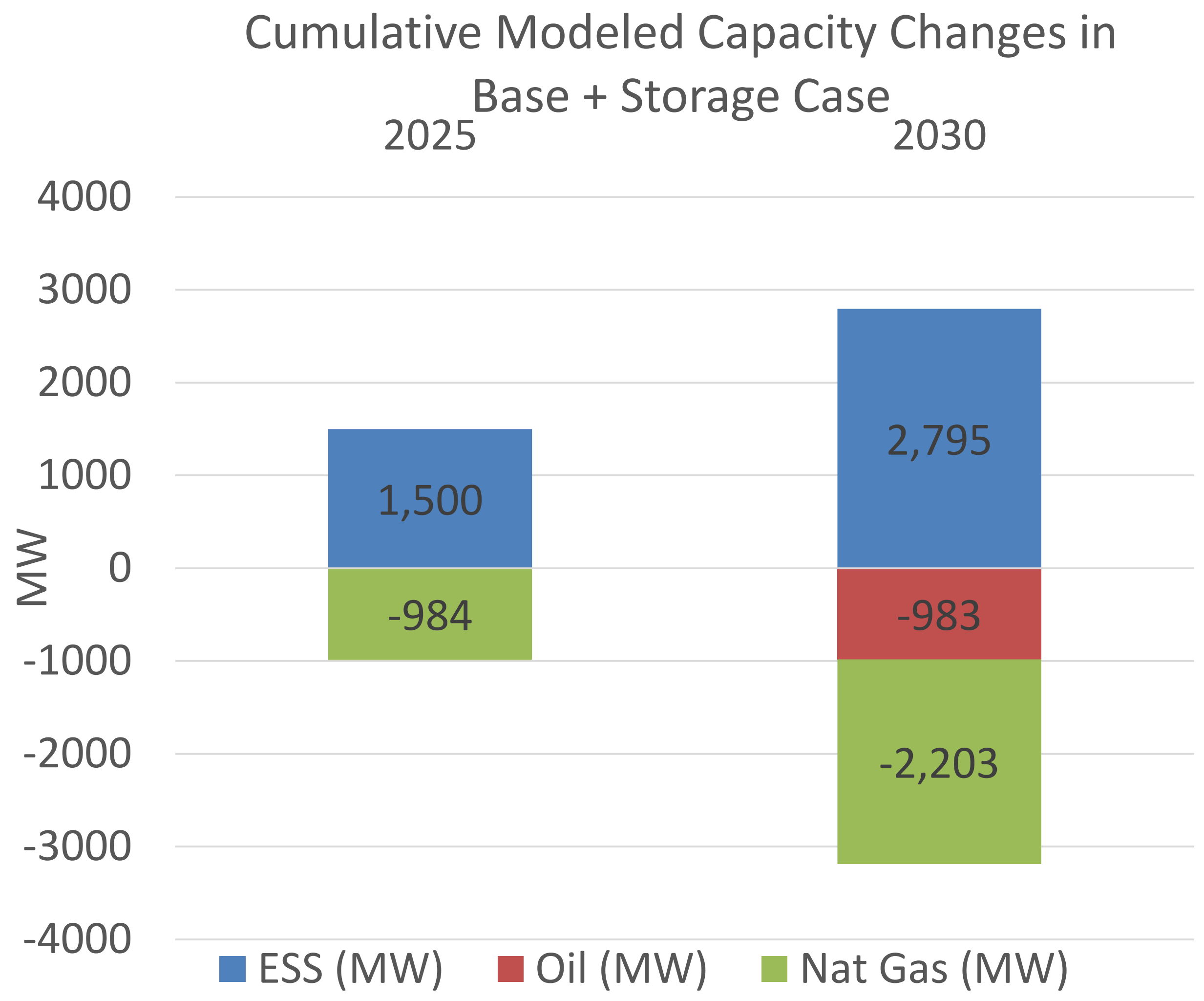
Base Case Benefits and Costs under a Resource Cost-Style Lifetime BCA

2025 (1,500 MW, 7,267 MWh)	
Model Benefits	**NPV in 2017 M$**
Ancillary Services	$75
Capacity Value	$516
Distribution Savings	$735
FOM	$81
Gen Cost Savings	$310
Avoided CO2	$24 (1.02 MMT)
Benefits	$1,740
Costs	$1,189
Net Benefits	**$551**

2030 (2,795 MW, 12,557 MWh)	
Model Benefits	**NPV in 2017 M$**
Ancillary Services	$140
Capacity Value	$732
Distribution Savings	$1,410
FOM	$214
Gen Cost Savings	$550
Avoided CO2	$44 (1.97 MMT)
Benefit	$3,090
Costs	$1,902
Net Benefits	**$1,188**

Presented is the benefit cost analysis for the 2025 and 2030 storage builds. These benefits require full dual market participation (retail and wholesale use of an asset). Transmission benefits from congestion relief are included in lower Locational Based Marginal Prices within “Generation Cost Savings.” Transmission deferral was not included in the model. Quantification of other emissions benefits beyond carbon were not included.

Base Case Capacity Additions with Storage Build



Note: In the base case with no storage built, no economic retirements of generators occur through 2025 and ~1 GW of economic retirements occur between 2026-2030.

This chart does not include new renewables built under the CES, which are captured as firm builds in the Base Case Inputs.

Peaker Retirement Case

Acelerex modeled an aggressive timeline for retiring all pre-1990 gas turbines in New York City and Long Island by 2025. This included 3,400 MW of generation with average utilization factors less than 2%. This represented the oldest of the peaker fleet, most of which are dual fuel (gas/oil) or oil fueled, and operate on oil when natural gas constraints require during the winter.

The Acelerex model was limited in its ability to consider alternatives to traditional gas plants. New transmission builds, additional load management, and local capacity in NYC from off-shore wind was not included. Loss of Load Expectation (LOLE) modeling was also not included. Key findings from this model:

- Retirement date of these plants directly affected when storage was needed. The Base Case built 1,988 MW of storage by 2025 and 2,795 MW by 2030 while the Peaker Retirement Case built 3,395 MW by 2025 and 3,633 by 2030.
- Storage can play a critical role in peaker replacement.
- Reliability requirements, including NERC, must consider Distributed Energy Resources including storage or these peaker plants will be required for contingency purposes because of their unlimited duration runtimes.
- Repowering peakers with storage and leveraging the existing footprint and interconnection and hybridizing traditional generators with storage to improve efficiencies and reduce emissions could both produce savings and should be examined.