Utility-Owned Storage in New York State

Applications for Transmission System Services

October 2024

Energy+Environmental Economics

Authors & Acknowledgements

Project Team

Energy and Environmental Economics, Inc. (E3) is a leading economic consultancy focused on the clean energy transition. For over 30 years, E3's analysis has been utilized by the utilities, regulators, developers, and advocates that are writing the script for the clean energy transition in leading-edge jurisdictions such as California, New York, Hawaii and elsewhere. E3 has offices in San Francisco, Boston, New York, Denver, and Calgary.

E3 Study Team: Kevin Steinberger; Tristan Wallace; Ben Joseph; Brendan Mahoney; Melissa Rodas; Lakshmi Alagappan.

Acknowledgements

This report was funded by National Grid USA Service Company, Inc. E3 is grateful for the review and feedback in the creation of this report from all National Grid contributors, as well as the various utilities and subject matter experts that were interviewed in support of this report; however, the final report conclusions and analysis reflect only those of the E3 Study Team.

Table of Contents

Table of Figures

Table of Tables

Background

New York State 6 GW Storage Target

In June of 2024, the New York State Public Service Commission (PSC) approved an ambitious storage target of 6 gigawatts (GW) statewide by 2030,[1] representing approximately 20% of the state's peak load. The energy storage target is designed to help the state to reach its commitment to a zero-emission electricity system by 2040, as laid out in the Climate Leadership and Community Protection Act (CLCPA) of 2019. In general, the Energy Storage Order (the Order) reaffirms the existing policy and vision that outlines the situations in which utility-owned storage (UOS) may be considered, such as when the storage device meets a clear system need and an asset owned and operated by a third party is inadequate to meet that need. As part of the Order, the PSC directed utilities within New York to examine "the non-market transmission and distribution services that energy storage projects can provide." This report was commissioned by National Grid as part of its effort to respond to the Order's request for an engineering, economic, and regulatory review of utility-owned storage used to provide transmission system services.

Overview of Storage as Transmission

Definition

Battery storage has the capability to provide transmission-related services such as contingency management, congestion relief and curtailment reduction. Storage as transmission also exists under two different regulatory frameworks: Storage as a Transmission Only Asset (SATOA) and Storage as a Transmission Asset (SATA). SATOA refers to a storage asset that can only provide transmission-related services with no market-focused activity. SATA, on the other hand, describes a storage asset that is used to provide transmission-related services but can also be used for market activities such as buying and selling energy on the wholesale market, providing ancillary services, and/or bidding into capacity auctions.

FERC Policy

Thus far, the approach of the Federal Energy Regulatory Commission (FERC) to storage as transmission has been nonprescriptive, maintaining flexibility for system operators. However, FERC casework outlines three primary considerations. First, the Commission considers whether the

[1] State of New York Public Service Commission. *Order Establishing Updated Energy Storage Goal and Deployment Policy*. https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Energy-Storage/2024-06-6GW-Energy-Storage-Order.pdf *(Pages 64-66)*

storage resource fulfills a "transmission function."[2] In the cases of *Western Grid* (2010)[3] and *American Electric Power* (2020),[4] the Commission established that storage as transmission must fulfill a transmission function; voltage support and thermal overload protection are transmission functions, but providing backup power supply and deferring new transmission construction or upgrades are not defined as transmission functions. Second, FERC considers if the storage resource was selected by a planning authority as the preferred solution to an identified transmission need. In *Nevada Hydro III* (2018)[5] the Commission dismissed a petition because California Independent System Operator (CAISO) had not yet completed its Transmission Planning Process. Third, the Commission considers if a system operator's level of operational control over the storage resource is consistent with its operational control of other transmission technologies. The arrangement in *Western Grid* (2010)[6] remains the foundation of current storage as transmission tariff language.

FERC has also released a policy statement outlining guidance for cost recovery in market-participating SATA resources. The 2017 Policy Statement clarified that, while previously-approved projects were prohibited from participating in market activities, the Commission would be open to dual-use projects that recovered costs from both market and rate-based mechanisms under three conditions.[7] The resource must: 1) avoid double-cost recovery from both market and rate-based mechanisms; 2) minimize adverse impacts on wholesale markets (i.e. wholesale price suppression from using ratepayer funding to subsidize wholesale energy bids); 3) and maintain system operator independence from market activities by operationally restricting the system operator's ability to manipulate the market via the resource's charge / discharge cycles. While the statement also listed several examples of potential solutions to these conditions, FERC also stressed that they were both open to other arrangements and would evaluate each proposal on a case-by-case basis.

Although some scenarios described here include an economic benefit of lower energy prices resulting from a battery shifting load, those savings would be passed on directly to customers and any benefit would be incidental to the battery's primary operational goal of enabling a more efficient transmission network. The economic benefits are incidental in nature due to the proposed battery dispatch schedules discussed below.

---

[2] The need to define a "transmission function" stems from Section 1223 of the Energy Policy Act of 2005 (EPAct) and FERC Order 679. The EPAct required FERC to establish incentive-based rate treatments for transmission infrastructure, and FERC Order 679 is FERC's rule for doing so. The EPAct section 1223 also defines energy storage as an "advanced transmission technology". FERC therefore needs to define when energy storage is considered transmission eligible for incentive rates, and fulfilling a "transmission function" is the technical part of that definition.

[3] *Western Grid*. 130 FERC ¶ 61,056 (2010).

[4] *AEP* 173 FERC ¶ 61,264 (2020).

[5] *Nevada Hydro III* 164 FERC ¶ 61,197 (2018).

[6] *Western Grid*. 130 FERC ¶ 61,056 (2010).

[7] *2017 Policy Statement* 158 FERC ¶ 61,051 at P 10 (2017).

Precedent in Other Jurisdictions

The Midcontinent Independent System Operator (MISO),[8] the Southwest Power Pool (SPP),[9] and Independent System Operator - New England (ISO-NE)[10] have FERC-approved tariff provisions for SATOA, with similar language describing the conditions under which SATOA may operate. All require a SATOA to be selected in their respective transmission planning processes as the preferred solution to a particular transmission system need. The tariffs require that the need be unsolvable through market solutions before SATOA may be considered. They also restrict storage resources chosen for SATOA from operating in the market except as strictly necessary to fulfill its transmission function, including charging to maintain the necessary state of charge. These resources must also be under system operator operational control. Separately, SPP and ISO-NE require the storage resource to be connected to the transmission grid, not the distribution grid, to ensure it only performs transmission functions.

[8] *MISO SATOA* 172 FERC ¶ 61,132 at P 1 (2020).
[9] *SPP SATOA* 183 FERC ¶ 61,153 (2023)
[10] *ISO-NE SATOA* 185 FERC ¶ 61,044 at P 1 (2023)

Review of Key Elements of Storage as Transmission

As the New York electricity system rapidly evolves to meet the goals of the CLCPA, battery storage can play a critical role in addressing transmission system needs more rapidly and more flexibly than conventional wires solutions. Conventional wires solutions may have development lead times that present challenges relative to the needs of this rapidly changing grid, without complementary battery storage resources also providing transmission benefits. Further, utilities are well-positioned to own these storage as transmission assets due to a combination of factors, including: their ability to operate the assets to maximize system benefits for New York ratepayers by providing transmission benefits that are not incentivized by the market; their unique understanding of the challenges facing their local transmission systems; and their capability to rapidly build infrastructure in New York State.

According to FERC precedent, storage as transmission assets must address transmission issues that cannot be addressed through market solutions. This restriction prevents utility-owned solutions from crowding out market participants. However, while some utility-owned storage transmission benefits are theoretically addressable by merchant storage systems, they are unlikely to be fully solved by the market in practice. This distinction is because market incentives are not always aligned with addressing transmission system needs, like congestion management, curtailment reduction, and grid stability services.

Transmission Services from Battery Storage

The usefulness of a storage device as a transmission asset stems in part from the changing nature of the electrical grid. The transition toward a zero-emission electricity system creates many new challenges through the increased prevalence of intermittent resources and a reduction in firm dispatchable resources, all of which will require increased transmission capabilities and flexibility. Having storage devices situated on the transmission grid provides another valuable tool to address these new challenges, namely the issues of congestion management, renewable curtailment reduction, and grid stability services. Compared to traditional wires solutions, storage as transmission can:

- Provide many of the same benefits including:
  - Mitigating congestion
  - Reducing renewable curtailment
  - Providing grid stability
- Be developed in less time, due in part to permitting and siting processes
  - Battery storage can reach commercial operation in 3-5 years
  - Traditional wires solutions can take up to 10 years from planning through commercial operation
- Be built with a smaller physical footprint and co-located with existing substations, reducing siting challenges that can arise with greenfield transmission development that is often faced with right-of-way needs

- Be added in smaller increments, rightsizing the need to avoid transmission overbuild
- Provide additional transmission solutions, such as stability services that are required of a grid transitioning away from fossil fuels

Utility Ownership of Storage as Transmission

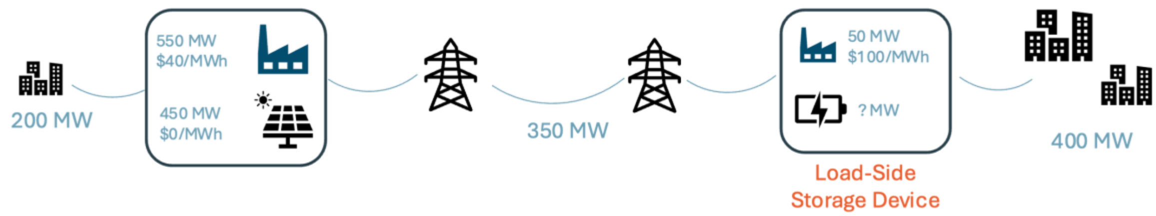
Utility-owned storage can meet specific non-market services on the transmission system that market-based solutions like merchant-owned storage cannot, including: congestion management, renewable curtailment reduction, and grid stability, due to misaligned economic incentives for market-based solutions to fully meet these transmission system needs. Congestion leads to price spikes that a profit-maximizing merchant storage operator would seek to leverage without fully resolving the congestion, but utilities can operate the battery to the benefit of the entire system and site and/or dispatch the battery to fully alleviate congestion. In other words, the utility can place a higher priority on reducing congestion costs to customers over maximizing arbitrage revenue for the battery. In this way, a utility battery could mimic the impact of increased transmission line capacity by reducing the cost of energy purchased on behalf of customers. Similarly, utilities can site storage assets in areas particularly susceptible to renewable curtailment and operate these assets based on dispatch schedules fixed on renewable generation rather than market signals, further supporting New York's renewable energy production policy objectives where a merchant battery's profit objective may lead to projects being sited elsewhere. In exploring the value of congestion and curtailment management, an economic valuation for storage as transmission was performed to quantify the benefits accrued to customers from these potential utility-owned storage use cases. The analysis discussed in this section explored hypothetical examples within National Grid's New York service territory.

Utilities also have technical advantages that come with control room operation of the battery. Utilities can control the battery in real time to maximize benefits to the transmission system rather than waiting upon scheduling control signals with third party operators, or simply responding to market price signals. Additionally, utilities can intentionally reserve battery capacity to stack value streams and address multiple use cases based on their local transmission system needs (e.g. congestion mitigation, curtailment reduction, stability) with one storage asset.

Congestion Management

A grid-scale storage device used for transmission can help to alleviate some or all of the congestion on the transmission system. A storage device placed on the load side of a congested line, as in the example in Figure 1, could charge when the line is not congested and discharge when the line is congested, lowering energy prices on the load side of the congested line.

Figure 1: Congestion Management Scenario with Load-Side Storage as Transmission



When faced with a congested line, as demonstrated through the illustration in Figure 1, a merchant battery owner would partially mitigate congestion by arbitraging between high and low price periods, but it would not have the incentive to fully alleviate the congestion because doing so would eliminate the opportunity for profits via arbitrage. The merchant-owned storage operator would deliver only enough power to keep the last remaining generator online — in this example a peaking combustion turbine (CT) — to set the marginal price and maintain arbitrage gain. Figure 2 shows that the illustrative storage device would be dispatched at a lower capacity for a longer period so that it doesn't fully displace the CT. On the other hand, a utility can operate the battery in a way that seeks to maximize system and customer benefits, as opposed to maximizing market revenue. The utility can therefore use the battery to fully solve the congestion and fully displace the CT in some subset of hours, as demonstrated in Figure 3, lowering total system costs.

Figure 2: Storage Charge/Discharge Relative to CT Dispatch under a Merchant Owner

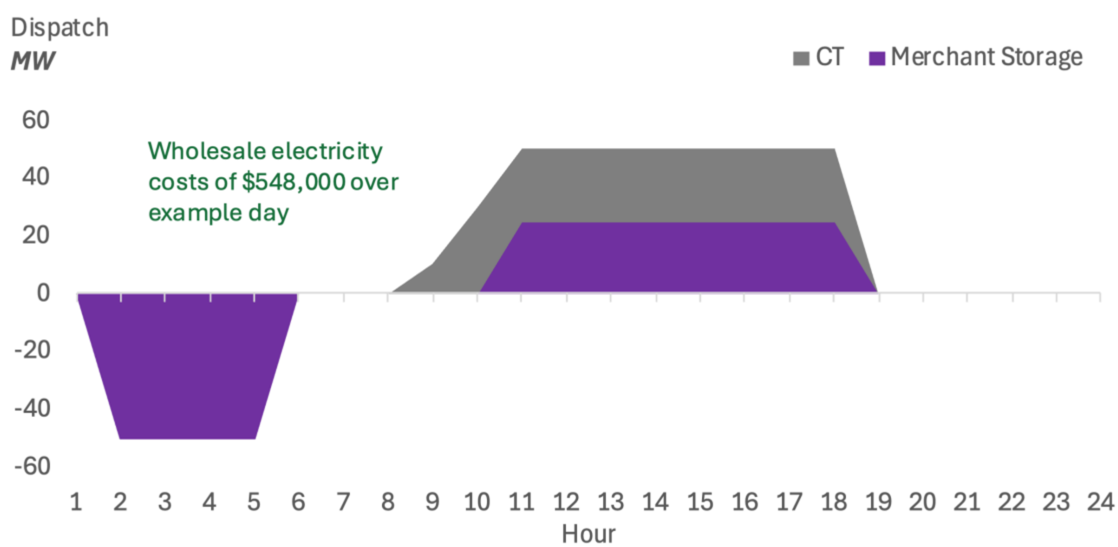
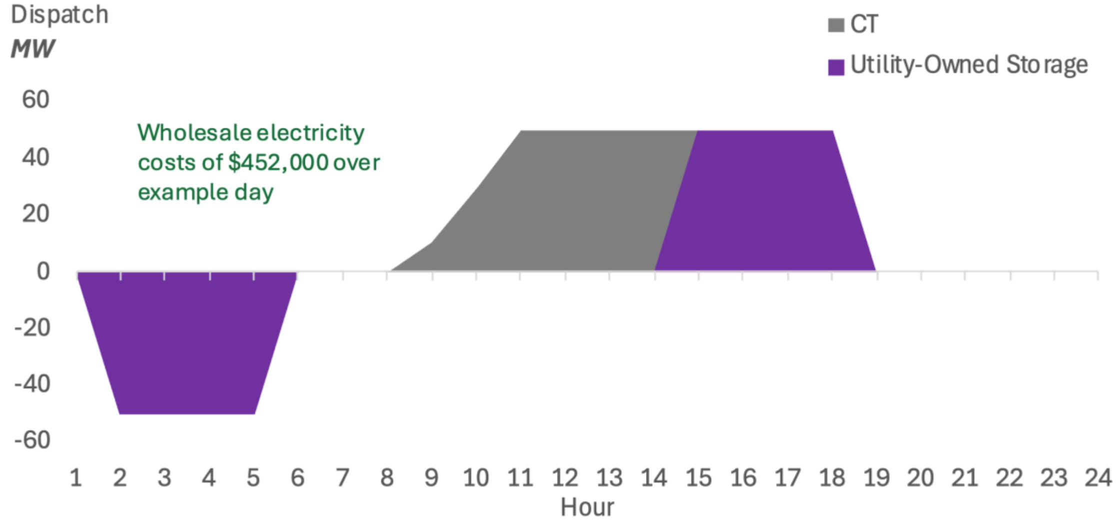
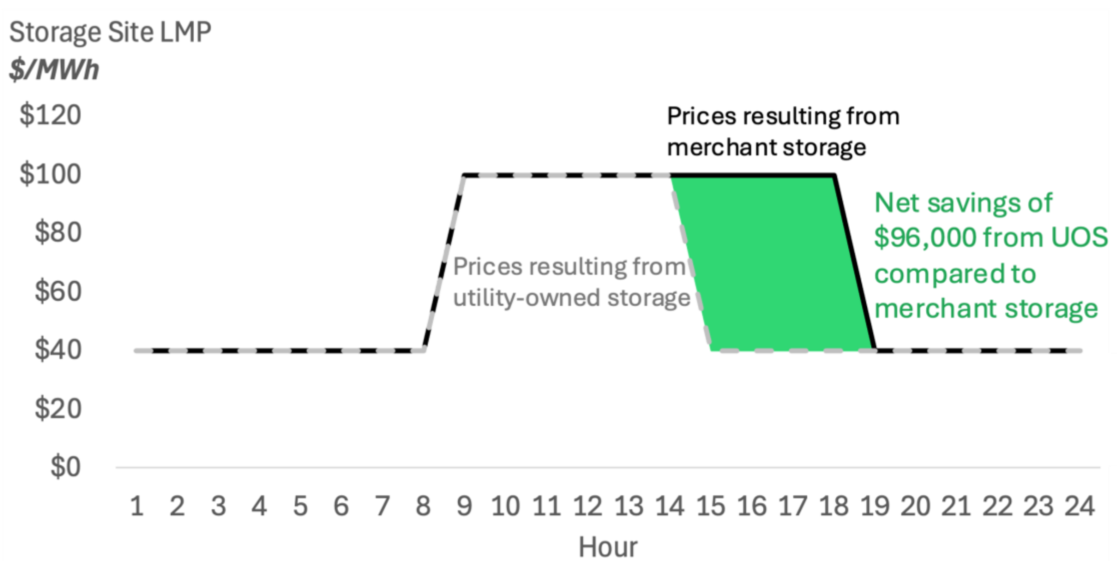


Figure 3: Storage Charge/Discharge Relative to CT Dispatch under a Utility Owner



The illustrative comparison of the impact on the energy price is then shown in Figure 4, where the storage dispatch under a utility would result in a price change but under a merchant owner it would not. After accounting for the differences in battery and CT dispatch, the change in energy price, as well as using the hourly load during the battery discharge (400 MW), total system costs would be expected to fall by $96,000 (18%) for a scenario with a storage resource owned by a utility compared to a merchant owner. While this example is a highly simplified system, it is intended to illustrate how profit-maximizing decisions by merchant storage operators can at times become misaligned with maximizing system benefits. This then could result in transmission system needs not being fully met by market solutions alone and thus justifying the deployment of regulated storage as transmission assets.

Figure 4: Impact on Energy Prices under Merchant- & Utility-Owned Storage



Economic Valuation of Congestion Management

To illustrate the value of storage as transmission for managing congestion, a process was created leveraging nodal production cost simulation and local transmission upgrade estimates.[11] The economic valuation included the following steps:

1. Using the results of a nodal production cost simulation of NYISO under achievement of the state's 70% Clean Energy Standard, congested branches in National Grid's service territory were identified.
2. Cost estimates for the conventional transmission upgrades necessary to resolve the congestion were developed.
3. The cost of the conventional transmission upgrade was levelized and spread over the hours of congestion at the branch in proportion to the congestion over the year.
4. For the remaining (non-congested) hours, the zonal LMP was used.
5. A battery resource was then dispatched against that hourly price stream using a fixed charge/discharge schedule to determine the benefits of storage as transmission to both defer the conventional transmission solution that would be needed to resolve the congestion and the impact from any incidental market-related value that would be passed on to customers.

The devices are assumed to operate under a *fixed charge/discharge* schedule, meaning that the hours in which the battery charges and discharges are pre-determined in a way that is expected to capture the most congestion value. This fixed charge/discharge schedule offers two key advantages: first, its pre-scheduled nature means the asset operates in a manner that is agnostic to market prices and will minimize adverse impacts on wholesale markets; and second, the simplicity of the fixed schedule would not require significant training or effort on behalf of the utility control room to optimize the operation of the battery. However, it should be noted that this fixed schedule does reduce the ability of the asset to optimize its operations to capture the greatest possible benefits.

The economic valuations of operating a storage device under a fixed charge/discharge schedule are shown in Figure 5. In this figure, the economic benefit of a storage as transmission asset is evaluated based on its ability to replace the congestion relief capability of a traditional wires solution. Rather than measuring the market value of reduced congestion, Figure 5 presents the value of deferred transmission infrastructure.[12] The total economic benefit includes that transmission deferral value plus the incidental market-related value from battery operations which is passed on to customers as cost savings (to avoid double-cost recovery from both market and rate-based mechanisms). These two value streams are compared against the value that would be captured by

---

[11] This analysis leveraged nodal production cost modeling that E3 and Hitachi Energy originally conducted to support National Grid's Clean Resilience Link project, supplemented with estimates of transmission upgrades provided by National Grid. For more abut the Clean Resilience Link, see: https://www.ethree.com/e3-national-grid-interregional-transmission/.

[12] For transmission deferral, a traditional transmission solution was identified that resolves the congestion on the identified branch, and the cost of the traditional transmission solution was spread out over the congested hours for the battery to dispatch against to capture that value of deferral.

a merchant-owned storage device simply by performing arbitrage in the wholesale energy market and by participating in the capacity market.

Figure 5: Economic Valuation of Storage for Congestion Management using Fixed Charge/Discharge Schedule

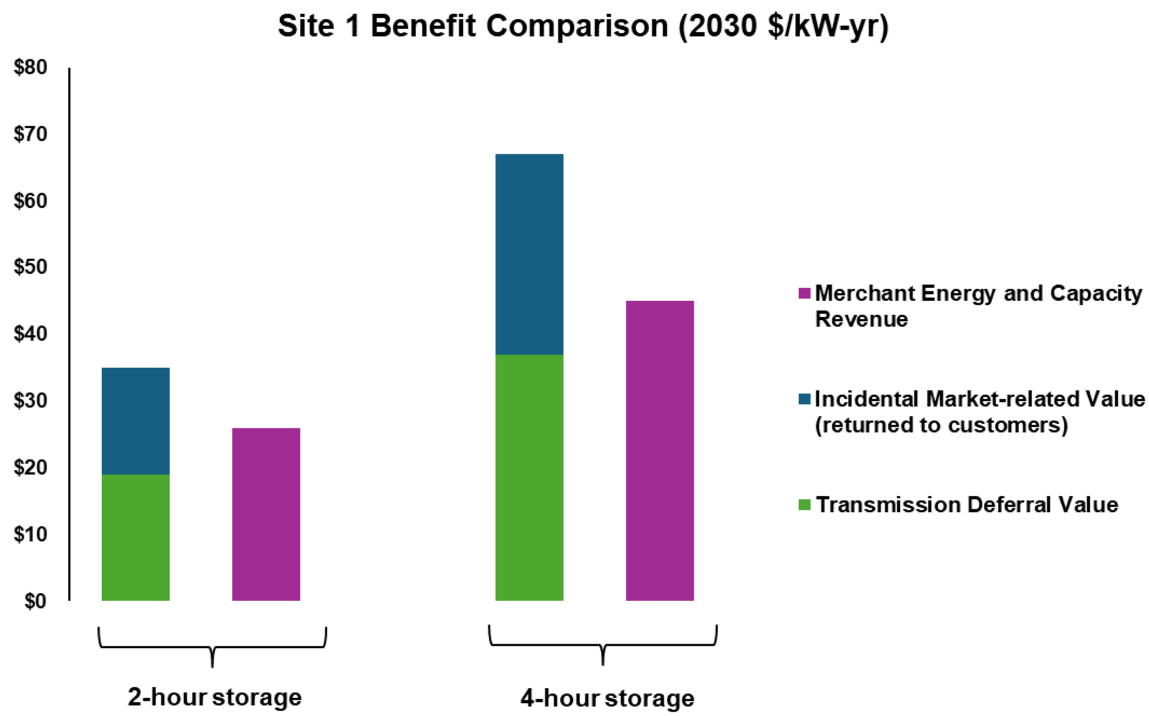
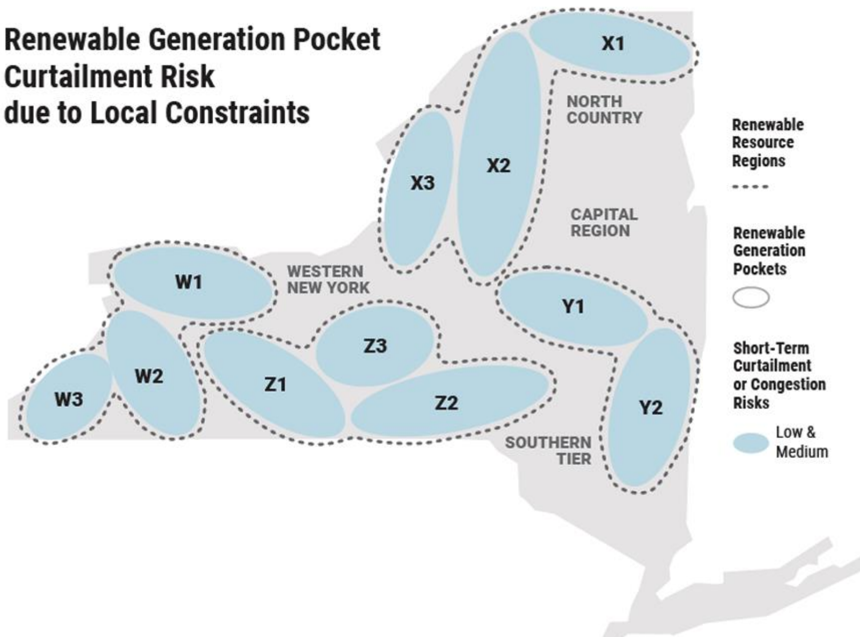


Figure 5 illustrates several points about the economics of utility-owned storage as a transmission asset. First, a four-hour battery outperforms a two-hour battery in terms of the amount of congestion value that can be captured. With the achievement of New York's 70 percent Clean Energy Standard goals, congestion can often last for several hours, and the longer duration of the battery, the better it will perform in mitigating that congestion. Second, a fixed charge/discharge battery can capture more value through deferring transmission investment and incidental energy market revenue than a dynamically dispatched merchant-owned battery. That is, a merchant-owned device will generate value through wholesale market streams (energy arbitrage, ancillary services, capacity market), but this value is less than the value captured by a utility-owned storage device for which the primary function is to decrease congestion on the grid, provided that new transmission infrastructure can be avoided as a result.

Reduction of Renewable Energy Curtailment

Solar and wind development is growing rapidly in remote areas far from population centers, meaning the transmission infrastructure to get the renewable energy from its source to the state's load centers is not fully built out. In its 2023-2042 System and Resource Outlook (Outlook)[13], the New York Independent System Operator (NYISO) found that future renewable energy generation in several regions of New York may not be deliverable to end consumers because of congestion on the transmission system, and in particular on local, low-to-medium voltage (<345 kV) networks. Often when transmission lines are congested, cheap renewable energy from one node cannot be delivered to another node, driving up energy prices on the load side of the congested line, and risking curtailment of the renewable generation, which also increases renewable procurement costs for the state with having to replace that curtailed renewable energy. As shown in Figure 6, the NYISO Outlook identified 13 regions in the state where a high penetration of renewables and a lack of transmission capacity would lead to significant curtailment risk, including many areas that overlap with National Grid's service territory (including parts or all of X1-X3, Y1, and W1-W3).

Figure 6: "Curtailment Risk" Pockets Identified by the NYISO



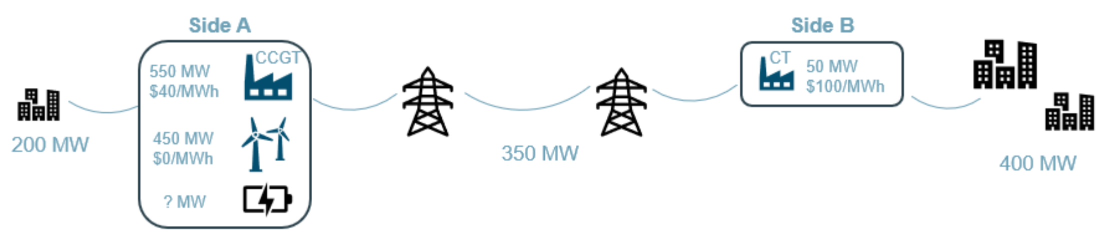
According to the NYISO, by 2035 a minimum of 2 terawatt-hours (TWh) per year of renewable energy in a low-demand scenario and up to 4 TWh per year in a high demand scenario are projected to be curtailed due to limitations of the transmission system near renewable energy production. This high level of renewable energy curtailment would not only increase energy market costs by wasting large amounts of low-cost generation, but it would also make achieving the state's CLCPA targets more difficult and costlier as the state would need to procure additional clean energy to replace the generation from curtailed renewables.

---

[13] NYISO. *2023-2042 System & Resource Outlook*. July 23, 2024. https://www.nyiso.com/documents/20142/46037414/2023-2042-System-Resource-Outlook.pdf

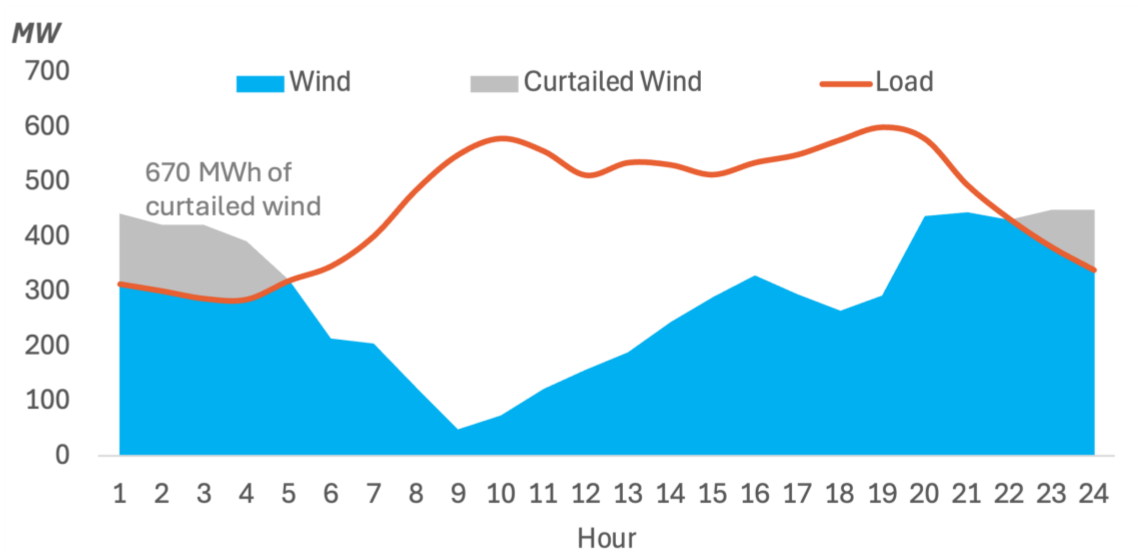
Utility-owned storage devices are well-positioned to provide transmission services by alleviating renewable energy curtailment. By shifting renewable energy throughout the day, a battery can allow more solar and wind power to be generated and delivered to end consumers, even in congested areas. Much like other forms of congestion, market price signals may not be sufficient to incentivize a merchant storage operator to fully alleviate curtailment, and thus excess curtailment may not be solvable by market solutions alone. Since market prices can be zero or even negative when renewable energy is being curtailed, charging a merchant-owned asset would be more profitable if curtailment is not fully alleviated. However, a utility-owned storage asset seeking to minimize system costs and maximize renewable generation would be sited and operated in such a way as to minimize renewable curtailment, even if that meant that zero or negative priced hours were reduced. As illustrated in Figure 7 below, storage devices can charge at times of high congestion, soaking up renewable energy and dispatching it when the line is no longer congested.

Figure 7: Curtailment Reduction Scenario with Generator-Side Storage as Transmission



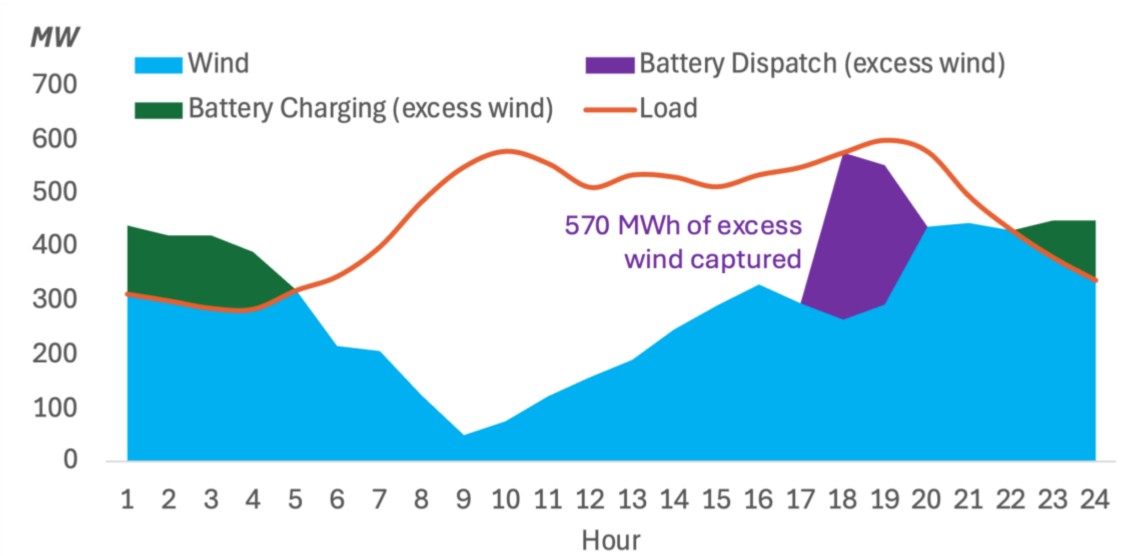
Prior to the utility-owned storage device charging with would-be curtailed wind generation, the price at the generator node would be zero or even negative in hours when the wind would be curtailed, as the wind generation outweighs the demand (and any transmission capability) in those hours. In the illustrative scenario shown in Figure 8, that would be in hours 1-5 and 22-24.

Figure 8: Wind Curtailment Reduction Scenario: Curtailment before Storage



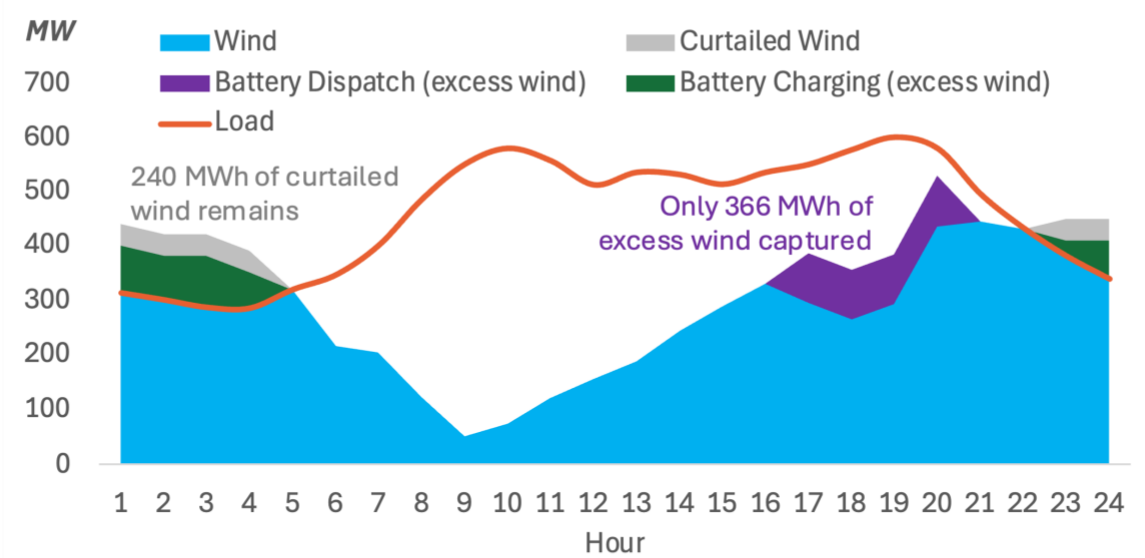
However, with the presence of a storage device, the utility could charge the storage device to eliminate wind curtailment in some hours, which would also lead to a flatter daily price curve, bringing the early morning prices slightly above zero but with the potential to lower prices significantly during peak hours. Figure 9 shows how wind curtailment could be eliminated and shifted to higher demand hours.

Figure 9: Wind Curtailment Reduction Scenario: Utility-Owned Storage



On the other hand, a merchant-owned storage device, seeking to maximize price spreads, would be incentivized to leave some wind curtailment in place, as illustrated in Figure 10. Similar to the dispatch pattern of a merchant-owned storage device in Figure 2, the merchant-owned battery demonstrated in Figure 10 would seek to charge over a longer period of time in the early morning, keeping a small amount of wind energy curtailment and thus keeping prices lower. This behavior would waste more renewable energy as compared to the utility-owned device in Figure 9, which would operate to fully reduce curtailment.

Figure 10: Wind Curtailment Reduction Scenario: Merchant-Owned Storage



Economic Valuation of Renewable Energy Curtailment Reduction

In most cases, when congestion is mitigated in a post-2030 New York grid, renewable energy curtailment will also be reduced. Since congestion management and renewable energy curtailment reduction often coincide, these two valuation streams cannot be "stacked" without the risk of double-counting potential benefits. However, the results of the analysis to reduce curtailment can still be utilized to calculate a related but separate benefit stream of reducing curtailment, which will allow more energy to be used by customers and the creation of more total Renewable Energy Credits (RECs) associated with that clean energy. In turn, the generation of additional RECs will also allow the state to avoid having to replace the curtailed renewable energy to meet renewable goals. The curtailment reduction benefits of two hypothetical storage sites are evaluated and summarized in Table 1.

Table 1: 2030 Renewable Energy Curtailment Reduction of Illustrative UOS

Site	Capacity *(MW)*	Duration *(hrs)*	Curtailment before Storage *(MWh/yr)*	Curtailment Reduction *(MWh/yr)*	Energy Benefit *($/kW-yr)*	REC Benefit [14] *($/kW-yr)*	Total Benefit *($/kW-yr)*
Site 1	170	4	88,580	42,716	1.76	8.02	10
Site 2	400	4	1,965,311	439,235	17.43	35.04	52.47

[14] This assumes roughly a $32/MWh REC value in 2030 (2030$).

Grid Stability Services

The transition to a grid reliant primarily on renewable energy sources such as wind and solar will require new tools and methods for grid operators to maintain system stability. For decades, fossil fuel-based power generators have provided the bulk of operating reserves, regulation services, and voltage support to the grid. However, as thermal power plants retire, and more variable resources like wind and solar are added to the grid, battery energy storage systems can provide utilities a rapidly dispatchable power source that can respond to sudden changes in system load or generation, and provide the frequency regulation and voltage support services needed.

There are several benefits to using storage as transmission for grid stability. Adding storage could simultaneously accelerate the retirement of emitting dispatchable resources like natural gas-fired power plants, as well as defer the development of high-cost emissions-free dispatchable resources (DEFRs) such as hydrogen combustion power plants or nuclear facilities. A utility-owned storage device would be better equipped than a merchant-based storage device given the ability to be directly controlled for the benefit of the transmission system in the utility control room, which could deploy the asset to further enhance grid stability.

Contingency Management

Contingency management is often thought of as another use case for utility-owned storage as transmission.[15] The potential benefit of using a storage device for contingency management is that it could allow for increased utilization of existing transfer capabilities because less capacity would need to be reserved for contingencies. This use case would beget production cost savings and the potential deferral of investment in new transmission lines. However, this may require procedural changes to use utility-owned storage for contingency management given current utility practices that seek to avoid the use of remedial action schemes in New York, which can be seen as potentially introducing new operational challenges and complications for reliability and asset health.

Engineering Review

Bridging the Technical Gap between Demonstration and Full-Scale Projects

The battery storage industry in New York is relatively nascent. For perspective, New York has a total of 369 MW of installed battery capacity[16] while California has over 10,000 MW.[17] Bridging the gap from early stages of adoption to a fully mature industry requires an investment in building the technical expertise to efficiently operate and maintain battery systems in a way that optimizes value

---

[15] NY-BEST. *Storage as Transmission Asset Market Study*. January 2023. https://cdn.ymaws.com/ny-best.org/resource/resmgr/reports/SATA_White_Paper_Final_01092.pdf

[16] https://www.nyserda.ny.gov/All-Programs/Energy-Storage-Program/Storage-Data-Maps/Statewide-Energy-Storage-Projects

[17] https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-energy-storage-system-survey

to the grid. The E3 team conferred with utilities in New York and across the country with experience building utility-owned energy storage, as well as trying to build their human capital and expertise to operate the systems, who conveyed the challenges and lessons learned, which provided important background for the discussion in this section.

Battery storage operations require new technical expertise from utility control room operators due to its dispatchability as both a load and a generator and its unique control platforms. Operators must establish standard protocols for battery operations to effectively transfer battery operations knowledge in case of employee turnover and to help train new technical team members to accommodate a growing storage fleet. They must also establish standard in-house operational interfaces that can be transferrable between battery projects regardless of the technology provider to avoid replicating the technical learning curve when bringing more capacity onto the system. Battery demonstration projects in areas with little grid-scale battery storage capacity can often experience maintenance difficulties because there are not enough trained technicians in the area to warrant prioritizing visits to a small demonstration project. But in other regions with larger, more readily available fleets of technicians, battery asset owners have been able to develop contracts to incentivize system performance and availability through guarantees that may not be viable options for smaller, more isolated projects.

Overcoming these operational and maintenances challenges, which have been observed across many utilities to date, may require an outsized initial investment in building relevant technical expertise relative to the size of new pilot projects demonstrating the transmission benefits of UOS. These internal investments currently face a “Catch-22”; it is difficult to justify scaling up such infrastructure for small-scale pilot projects alone, but the lack of internal infrastructure also has led to significant operational and maintenance issues at current pilot projects that limit their effectiveness and their ability to encourage future larger storage projects.

If the PSC were to enable utility ownership of storage, we recommend that these challenges be considered. For example, the PSC could consider providing assurance through demonstration phases that UOS will have opportunities for larger more meaningful contributions to the state’s 6 GW battery storage deployment target, provided that operational milestones are achieved and the assets are performing transmission functions as expected without undue impact on the market. Such assurance could be tied to “stage gates,” aligning with certain milestones achieved by demonstration projects. This would in turn allow utilities to make investments in training and the requisite internal infrastructure that would be commensurate with the scale of a long-term program in which utility-owned storage plays a key role in addressing future transmission system needs.

NERC System Performance Requirements

North American Electric Reliability Corporation (NERC) sets standards called Transmission System Planning Performance Requirements[18] that system planners must comply with to prove their system reliable under a wide range of hypothetical operational scenarios. There is some debate as

[18] https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf

to the operational requirements of storage within these NERC requirements. If interpreted such that battery storage must hold capacity in reserve in case of a contingency event, it would hurt its economic value proposition because the battery would have to be oversized relative to the economic and policy-based need in order to reserve capacity for reliability purposes. That additional reserved capacity comes with incremental capital costs without being able to provide additional system benefits; however, this capacity may not be necessary to comply with the intent of the requirement given the significantly faster response times of storage assets. A priority for grid planners could be to ensure dynamic response to contingency events complies with NERC standards to enable the full battery capacity to be optimized for other economic and policy-based use cases while contributing towards system reliability.

System Planning and Operations of Storage as Transmission

Wires Solutions vs. Storage as Transmission

Through the NYISO Comprehensive System Planning Process (CSPP), the NYISO conducts transmission system planning by combining numerous inputs such as demand growth expectations, reliability planning, interregional planning, and interconnection studies. Under the CSPP, the New York State utilities are required to generate their own Local Transmission Owner Plan (LTP). The projects identified by utilities in their LTPs are reviewed by the NYISO and their cost effectiveness is compared against regional transmission projects, informing the transmission plan ultimately described in the CSPP.

National Grid uses power flow analysis to identify transmission system needs and the proposed solutions for those needs that are detailed in its LTP. Any storage as transmission solution would go through the same process as a traditional wires solution to meet a local system need identified by the LTP. Power flow modeling looks at snapshots in time during periods of high system stress (e.g., high system load or during and after some contingency event). However, as system needs evolve under higher penetrations of renewable energy, these snapshots may or may not capture the role that battery storage can play in meeting local transmission system needs.

One key aspect that would aid in the assessment of batteries in transmission planning is an expansion of production cost modeling capabilities in NYISO's transmission planning analysis. This production cost modeling could be used to identify additional hours beyond those considered in conventional power flow snapshots — e.g. combinations of higher or lower demand with higher or lower renewable output — that may present challenges on the local transmission system. The exploration of system needs within a production cost framework would allow a transmission planner to better profile the needs of the system, instead of only exploring a limited number of bookend snapshots, which is often the case in most analyses today. Given the vast interchange of power that flows through (not just into or out of) the National Grid network in New York, this will be important to have the capability to explore the full value of battery storage given how its load changes, in addition to the loads of other neighboring regions. Further, storage as transmission projects would benefit from the consideration of storage in production cost modeling as not only merchant entities responding to market revenue signals, but also devices placed on the transmission grid for the purpose of providing transmission system services.

Real-time operation of utility-owned storage

One of the chief advantages of utility-owned-storage is that the operation of the battery could be dispatched for the benefit of the transmission system by the utility control room, allowing the utility to predictably schedule the operation of the battery in a way that maximizes the benefits to the local transmission network, which would not necessarily be aligned with how a battery is dispatched for the purpose of maximizing market revenue. Utility ownership would allow fully operational control and flexibility by the utility. Other utilities with experience with operating storage that were interviewed in the development of this report, relayed that this type of flexibility for responding in real time to contingency events and grid stability needs have generally experienced challenges under other contractual arrangements with third-party ownership, due to the lag time between a utility requesting dispatch and the third-party responding being too long to deliver maximum value for these use cases. The degree to which ownership would be more valuable here would depend on the nature of the utility contract with the third party. A merchant battery owner operating a battery would only be responding to market price signals (energy and ancillary services) which do not always align with what is most efficient for the transmission system.

When operated by a utility, a four-hour battery storage resource can also reserve battery capacity for different use cases. For example, a utility could operate a battery in which three-hour's worth of capacity is used to reduce transmission congestion and minimize renewable energy curtailment while 1 hour is reserved for grid stability services by pre-empting contingency events before they occur. This value stacking adds to the flexibility and overall value of the battery.

Review, Approval, and Cost Recovery of Utility-Owned Storage

Development Lead Time (in comparison to wires solutions)

Another central advantage of using a battery as a transmission device is the speed with which the battery can be built and become operational, in comparison to a traditional wires solution. Traditional wires solutions can take up to 10 years from early stages of planning through to commercial operation [19] while storage systems can be completed in under 5 years, when construction and environmental permits have been received.[20]

[19] https://ifp.org/how-cost-allocation-works-for-transmission-lines/

[20] This conservative estimate was based on the total timeline for utility-scale solar development. Storage may be significantly faster due to its smaller footprint considering environmental reviews constitute a significant amount of solar development timelines. https://ei-spark.lbl.gov/generation/utility-scale-pv/project/innov/#:~:text=Typically%2C%20a%20utility%2Dscale%20solar,interconnection%20(REF%3A%20SEIA).

Approval

FERC, through the *Nevada Hydro III (2018)* project, established a precedent that SATA and SATOA needs to be established through a system operator transmission planning process, which means that a SATA or SATOA device would require approval from the NYISO. Thus far, the NYISO has considered energy storage to be a generation asset ineligible for cost-of-service rate recovery, despite its ability to perform as a transmission asset. However, the NYISO is studying how to amend market rules to enable SATA and SATOA to operate in New York and is planning to issue a Market Design Concept Proposal that covers the following issues:

- Evaluating storage as transmission in the Comprehensive System Planning Process (CSPP),
- Operating considerations including dispatch conditions and mitigation of market manipulation,
- Scheduling and dispatch control, and
- Treatment of market revenues.

The use cases that the NYISO is exploring for storage as transmission could signal what may ultimately be allowable in NYISO. The use cases that the NYISO has explored in September 2023 included the following:

- N-1 Contingency: 200 MW / 200 MWh battery at Shore Road 345 kV substation.
    - Allow system operators time to react to N-1 contingency, keeping the line under rating and reducing congestion.
- Voltage Support Service: 50 MW / 50 MWh battery at Oswego complex near Edic 345 kV Substation
    - Provide voltage support to maintain a consistent Central East interface transfer capability when generators in Oswego area are out of service.
- Reduced Local Capacity Requirement: 200 MW / 200 MWh battery in Zone J, Mott Haven 345 kV substation
    - Increase transmission security limits in Zone J to improve reliability and reduce the installed capacity requirement.
- Curtailment Reduction: Northern New York
    - The assets would charge and discharge daily during set time periods that vary by season, with the storage charging during periods of high renewable generation and discharging during periods of low renewable generation.

Further, as mentioned above, to gain FERC approval a case must be made for why the storage serves a specific transmission function.

Cost Recovery

For a SATOA device, cost recovery of the asset is achieved through transmission rates in the same way a traditional wires investment would be recovered. This type of cost recovery has previous FERC approval in MISO, ISO-NE, and SPP. To qualify for cost recovery through transmission rates, the storage asset must only be used in transmission reliability events or as pre-support, or transmission services. It must not earn market revenue. For a SATA device, cost recovery is still achieved through transmission rates. However, any net revenues that are collected by the utility on the wholesale markets by dispatching the battery are also passed on to customers in terms of rate reductions. In other words, the cost that is passed on to customers as transmission rate increases is partly made up by rate decreases from the recurring net revenues earned by the battery's dispatch.

Summary

FERC has indicated that tariff filings that allow storage to operate as a transmission asset must enable storage to meet a transmission need that would otherwise not be solved by market solutions. Utility-owned storage systems operated as transmission assets meet this condition due to both the differing economic incentives between utilities and merchant storage owners and the utility's connection to control center operations. Utilities are incentivized to maximize system benefits to economically justify rate-based cost recovery of storage assets. This means utilities can site and operate the battery to eliminate the price impacts of congestion and renewable curtailment that burden their customers. On the other hand, merchant projects benefit from and are disincentivized from eliminating the price impacts of congestion and curtailment. Additionally, utilities can operate battery storage systems in real time from the control room to respond to grid instability signals, providing stability services as an additional benefit to other economic transmission benefits.

Deploying utility-owned storage requires technical and engineering considerations around reliability requirements and battery operations and maintenance, as well as coordination with regulatory agencies around their requirements for reliability. There are also challenges in establishing the technical capabilities for utility operations and the service providers they contract to provide and maintain storage technologies. Investing in building these technical capabilities may require assurance that utility-owned storage capacity will grow beyond small demonstration projects.

Production cost modeling shows that the value that a utility-owned storage system provides in deferring a traditional transmission solution that would otherwise be built to address congestion is greater than the market revenues a similarly sized merchant project can capture from wholesale market participation. This value proposition holds true even when storage charging and discharging schedules are fixed rather than fully responsive to price signals, a design choice ensuring that utility-owned storage has minimal market impacts.

Utility-owned storage can be deployed to help New York achieve its climate and storage deployment goals while providing a uniquely valuable resource in addressing transmission needs like congestion reduction, renewable energy deliverability, and grid stability. Utility-owned storage is a distinctive solution because it can deliver these transmission benefits that are not efficiently addressable by market solutions and can be more easily deployed and right-sized to meet system needs than traditional wires solutions.