September 1, 2023

FirstLight Power Comments: Massachusetts 2022-2023 Energy Storage Study Stakeholder Session Two

Company Overview

FirstLight is a leading clean power producer, developer, and energy storage company serving North America. With a diversified portfolio that includes over 1.6 GW of operating renewable energy and energy storage technologies and a development pipeline with 2,000+ MW of solar, battery, and offshore wind projects, FirstLight specializes in hybrid solutions that pair hydroelectric, pumped-hydro storage, utility-scale solar, large-scale battery, and offshore wind assets.

Our mission and vision is to accelerate the decarbonization of the electric grid by owning, operating, and integrating large-scale renewable energy and storage assets to meet the region's growing clean energy needs and to deliver an electric system that is clean, reliable, affordable, and equitable.

FirstLight's clean energy facilities in New England produce over 690,000 MWh of emissions-free generation, reducing the region's carbon footprint by more than 780,000 tons annually. In addition to our clean energy generation facilities, we also own and operate the 1168 MW Northfield Mountain pumped hydro storage station and 29 MW Rocky River pumped hydro storage station, respectively the largest and third largest energy storage facilities in New England, 2 MW of solar PV, and 1.5 MW of behind-the-meter battery storage in Massachusetts. Our facilities represent over a billion dollars of private investment in the region, employ nearly 200 people, and support our communities in Massachusetts with more than $15 million in local property taxes every year.

Subject: Comments on the modeling for the cost-effective deployment and utilization of both new and existing mid-duration and long-duration energy storage

I. Background

The Clean Energy and Climate Plan for 2050 (CECP), released in December 2022, found that to meet economy-wide green-house-gas (GHG) emission reduction targets by 2050, a 93%

reduction in electric sector emissions is required.[1] The CECP (Phase Scenario) forecasts a substantial increase in electric load in Massachusetts, from approximately 55 TWh to 127 TWh between 2020 and 2050. Over the same period, the CECP forecasts the addition of 23.5 GW of solar, 23.4 GW of offshore wind, and 18 GW of storage within the Commonwealth, 7 GW of which is from long-duration energy. As required under Section 80, DOER and MassCEC with the help of its consultant, E3, are conducting a study to examine how mid- and long-duration energy storage could potentially benefit the grid and ratepayers, including through improving grid reliability. A second stakeholder session was held on August 16, 2023, to preview work to date and raise several areas for discussion and feedback. The presentation laid out the workplan and objectives of the study, summarized modeling assumptions and methods.

II. Study Approach

The study assumes the CECP Phased Scenario loads and resource mix. The study will use E3's Renewable Energy Capacity Planning Model (RECAP)[2] to assess how the reliability (taking a resource adequacy view) of the system changes as additional mid- and long-duration storage is added. The DOER/E3 presentation is not clear on these details, but ostensibly the model begins with the resource mix, including storage, from the Phased Scenario and adds increments of storage with increasing duration until the system meets reliability criterion (1-day-in-10-years). We are concerned that this approach will limit available insights into the potential benefits of having mid- and long-duration storage as resources in the emerging clean energy portfolio – including the existing pumped storage facilities. The approach starts with a fixed portfolio, so eliminates all real-world uncertainty associated with the timing of resource entry and exits, transmission and distribution expansion, and load growth. Further, the Forward Capacity Market addresses resource adequacy needs and the ISO-NE ancillary services and dispatch will maintain reliability. The real question is whether reliance purely on ISO-NE market signals will deliver the full benefits possible from existing and new electric storage. In addition, the modeling also appears to ignore the impact of location, transmission, and gas constraints on storage benefits, particularly in load pockets. Additionally, it is not clear how flexible demand is treated in the modeling.[3]

The core question of this study is to what extent the inclusion of flexible and responsive resources like mid- and long-duration storage under contractual arrangements maximizing the benefit for Massachusetts' consumers will allow the power system to decarbonize in a more

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[1] https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050#:~:text=Also%20on%20December%2021%2C%202022,greenhouse%20gas%20emissions%20in%202050.

[2] https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/#:~:text=E3's%20Renewable%20Energy%20Capacity,energy%20storage%2C%20and%20demand%20response.

[3] The CECP identifies "innovative load flexibility" as a key balancing resource (CECP at p. 75).

cost- effective way and what procurement requirements DOER should establish for mid and long-duration storage to contribute to greenhouse gas emission limits, promote offshore wind energy and other renewables, transport energy from periods of low energy demand to high energy demand and enhance reliability at the minimum ratepayer cost. Because the proposed model holds the portfolio static, except for resource adequacy, there is no clear way to measure these benefits.

Ideally, the study would use a capacity expansion model that builds out a least cost portfolio of resources to achieve the state's decarbonization goals and reliability standards. The approach that DOER/MassCEC proposes takes energy and capacity prices from the New England Avoided Energy and Supply Cost (AESC) study, which extends through 2032, extrapolating values out to mid-2050. In the wholesale market, wholesale energy and capacity prices are a consequence of the resources in the market. To the extent that the CECP phased buildout case and the AESC assumptions are not aligned, the market revenues will not reflect the supply and demand conditions. Performing a proper capacity expansion would ensure that the cost revenue tradeoffs are explicitly and intuitively linked.

Further, as evidenced by the operation of existing Northfield Mountain Pumped Storage facility, the ISO-NE market signals result in under-utilization of electric storage. At NMPS, approximately 75% more storage throughout is possible. This could be captured by contract terms that incentivize additional electric storage throughput where the savings to consumers exceed the cost of supplying the service. Under existing market rules, the reliance on energy arbitrage pricing often places electric storage at the energy market margin during discharge. Contractual arrangements that meet round-trip electric costs could decrease the marginal cost of electricity during electric storage discharge periods.

III. Technical Comments

A. Dispatch of Battery Classes by Duration

The study appears to acknowledge that 100-hour duration batteries (LDES) can provide significant capacity value to the New England portfolio, stating: "*If CECP 2050 is realized, New England portfolios will have abundant renewables, particularly offshore wind, for storage to charge from; in these portfolios, almost 20 GW of LDES can replace "perfect" firm capacity without sacrificing reliability in 2050.*"[4] However it appears that the LDES, despite its inefficiency relative to the other storage classes, is used to serve daily peak rather than being held for capacity during shortage events. Storage is modeled in three different durations, 4-hour, 8-hour, and 100-hour storage, which in 2050 serves primarily to flatten peak load, shifting

[4] Charging Forward: Energy Storage Toward a Net Zero Commonwealth – Stakeholder Session #2: Study Update and Draft Results – Slide 42

surplus solar generation from midday to the evening peak period.[5] Based on the graph presented it appears all classes of storage, 4-hour, 8-hour, and 100-hour, participate in discharging to serve the evening peak period it appears that the LDES provides the bulk of the discharge needs during the Summer Week in July.[6] This seems counterintuitive as LDES is assumed to be less efficient than either the 4- or 8-hour duration batteries, and therefore more likely to seek capacity payments rather than wholesale market revenues via price arbitrage.

As the period of discharge does not seem at all aligned with the duration of the LDES it would be helpful to understand if the introduction of an additional storage class, 12-hour or 16-hour duration, would reduce the usage of LDES for addressing the needs of daily peak load. This would enable the LDES class of batteries to be available for longer duration periods when intermittent generation is low.

Furthermore, there are existing LDES storage assets in the Commonwealth that do not appear to fit within any of the studied classes. It would be useful to understand how these existing resources are modeled and if possible, to model them as representative of real-world operations as possible. This is important to be able to understand the benefits they bring to the system in 2023, 2030, 2040 and 2050. The benefits provided to the ISO-NE system by existing LDES assets is very important as the forecast model does not consider real world delays common to the development of new storage assets such as supply chain disruption, construction delays or any of the other types of delays common to developing grid-scale assets. Existing LDES assets are ideally positioned to act as a buffer for the ISO-NE system in the event there are delays in the development of new resources and therefore should be modeled and considered in detail. These resource have already provided valuable grid services for years and any future LDES resources that are constructed should not erode that value.

Additionally, it would be helpful to understand why the LDES class of batteries appears to be used to address daily peak load as compared to how other capacity resources, thermal unit for example, are dispatched and the revenue streams realized by each of the resource classes assumed to be contributing to available capacity.

B. Capacity Market Revenues

The study states that "*The strong diversity of benefit between LDES and offshore wind, driven by the availability of offshore wind to recharge LDES during challenging winter weeks, is essential to realizing the high-capacity value of storage.*"[7]Based on the presentation, battery resources are expected to receive a value stream from the capacity markets in 2023.[8] Capacity prices are

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[5] Ibid – Slide 28.
[6] Ibid – Slide 28.
[7] Ibid – Slide 42.
[8] Ibid – Slide 12.

an input to the model and based on historical pricing with adjustments, which may understate the cost of capacity on the system given the assumed increased level of intermittent resources and reduced level of dispatchable thermal assets.[9] Given the importance placed on batteries, especially LDES, in 2050 to provide capacity to the system, it would be helpful to understand how the expected capacity payments evolve over time for each class of battery, and the drivers behind the changes in capacity revenue. How is the value of capacity calculated over time in the model? Are there differences in locational value? What are the capacity prices used in the model and are they sufficient to incentivize LDES or thermal asset owners to provide the required capacity? Given the uncertainty regarding the level of future capacity pricing it would be helpful to have a series of sensitives around the datapoint to assess the relative importance of the changes in assumed values and provide perspective.

C. Study Assumption: Thermal Capacity Available in 2050

The study assumes the CECP Phased Scenario loads and resource mix, which has 15 GW of gas fired thermal capacity available in 2050[10]. However, by 2050 plant operators are faced with an environment of reduced capacity factors, and therefore energy market revenues as cheap intermittent resources combined with energy storage provide the bulk of the energy required. However, thermal units are assumed to provide capacity, which means plant operators will be required to keep their units in peak operating conditions with fuel on hand to satisfy their obligations to the capacity market. Are the modeled capacity payments received by these generators sufficient to incentivize them to operate in this manner, which is a departure from how gas fired generation has historically been dispatched? If not, would increasing capacity payments to this level produce a different set of incentives for LDES?

Furthermore, in the event that modeled capacity payments were lower than the level required to incentivize the assumed operation of thermal units, would the value of existing LDES assets increase as they would be ideally positioned to provide the required capacity to the system.

D. Study Assumption: Firm Capacity Available from Import Markets

The study assumes the CECP Phased Scenario loads and resource mix, which assumes firm imports increase from 16 GW in 2030 to 23 GW in 2050.[11] In addition to which, the model results for the 2050 Winter week appear to rely heavily on imports to meet load, especially over the evening peak period.[12] The surrounding import markets – New York, Atlantic Canada and

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[9] The State of Energy Storage and its Future Role in the Commonwealth – Stakeholder Session #1: Study Overview, Approach and Early Insights – Slide 20.
[10] Ibid – Slide 29.
[11] Ibid – Slide 29.
[12] Charging Forward: Energy Storage Toward a Net Zero Commonwealth – Stakeholder Session #2: Study Update and Draft Results – Slide 29

Hydro Quebec – all having their own electrification and decarbonization programs, suggesting their systems will likewise require firm capacity during periods of low renewable generation or high winter load and very likely not have an excess of firm capacity to export. This dynamic is further exacerbated by the correlated nature of offshore wind production for New York, New England and Atlantic Canada which suggests historical sources of import energy maybe less able to export to the Commonwealth during periods of low offshore wind generation. Additionally, these regions are also likely to experience similar weather patterns which when paired with increased electrification may lead to a decrease in the availability of imports during high load hours caused by either extreme cold or warm.

E3 has indicated the intention to run a no imports sensitivity scenario which will provide valuable insight into the ability of the system to maintain reliability during peak load periods using internal resources. The results from this scenario will be beneficial to exploring what additional incentives, via the capacity markets or some other mechanism (for example, programs similar to the current Winter Reliability Program), would be required to provide the resiliency needed for the ISO-NE system during a cold weather event when imports were not available. Furthermore, this scenario should show how reliant the ISO-NE system is to new and existing LDES assets to meet winter and summer peak loads in the event of an unavailability of imports.

E. Study Assumption: Solar Generation Capacity Factor

The study appears to assume an aggressive generation profile for Solar resources, with the weighted-average hourly capacity factors as high as 40% in January and above 60% in the summer months.[13] It would be useful to understand the assumptions regarding technology and location that produce this solar generation profile. Additionally, the benefits of 4-hour and 8-hour storage appear to primarily be derived from the ability to shift this solar generation from midday to evening peak hours, it would be valuable to see the effect of assuming a more modest solar output on the value streams for these storage resources and the system as a whole.

F. Study Assumptions: Battery Degradation

The study provides an example of a charge/discharge profile for a 50MW 4-hour lithium-ion battery in both 2023 and 2040, which appear to show the battery cycling (one full charge and one full discharge) daily.[14] If this frequent cycling is the typical operation for a battery resource it would be beneficial to understand how degradation is modelled for future lithium-ion battery storage, and how this would impact the value streams of new SDES and LDES assets.

[13] Ibid – Slide 24.
[14] Ibid – Slides 13&14.

Additionally, there are existing LDES assets on the ISO-NE system (such as pump storage systems) that would not suffer from the degradation/cycling problem, and if degradation rates are not modeled these assets would have an understated value to the ISO-NE system relative to new SDES systems that do suffer degradation. Furthermore, it would be beneficial to understand if the relative value of the short duration energy storage (SDES) and LDES are sensitive to the degradation of high cycling batteries.

IV. General Comments

As stated previously, the core question of this study is to what extent the inclusion of flexible and responsive resources like mid- and long-duration storage will allow the power system to decarbonize in a more cost- effective way and what procurement requirements DOER should establish for mid and long-duration storage to contribute to greenhouse gas emission limits, promote offshore wind energy and other renewables, transport energy from periods of low energy demand to high energy demand and enhance reliability at the minimum ratepayer cost. In considering development of mechanism to incentivize the optimal resource mix to enhance reliability and minimize ratepayer costs, existing LDES systems should be considered in parallel with future LDES systems, in order to ensure new development is not favored at the expense of existing LDES systems. This is of vital importance as existing LDES systems are in place to provide a buffer of capacity and resource shifting capability on the system at any time, which serves as a hedge for the uncertainty surrounding the development and timing of new resources. Existing systems must not be rendered obsolete or uncompetitive by incentive structures aimed at developing additional storage resources.

Additionally, the study acknowledges that in 2050 LDES can provide up to 20GW of firm capacity to the ISO-NE system. Efficient use of existing storage assets on the ISO-NE system are vital to the transition to a decarbonized ISO-NE system as these assets will be required to pioneer the transition from traditional price arbitrage to providing capacity for system stability purposes. At NMPS, approximately 75% more storage throughout is possible beyond the economics signaled by the ISO-NE markets. This additional potential could be captured by contract terms that incentivize additional electric storage throughput where the savings to consumers exceed the cost of supplying the service. Under existing market rules, the reliance on energy arbitrage pricing often places electric storage at the energy market margin during discharge. Contractual arrangements that cover round-trip electric costs could decrease the marginal cost of electricity during the additional electric storage discharge periods that would deliver benefits to Massachusett's consumers. It would be very helpful to understand how the exiting LDES assets on the ISO-NE system can contribute to firm capacity over the study period, and how their capacity revenues evolve. It will be important to appropriately incentivize asset owners to operate their LDES assets in such a way that it provides the maximum benefit to the ISO-NE system while minimizing ratepayer costs.

V. Conclusion

As we've seen in recent years in places like Texas in 2021 the lack of reliable, dispatchable electricity can have a devastating impact on our communities as a whole. Further, the increasing climate volatility we're seeing every year underscores the need to accelerate our efforts to decarbonize our economy. It is clear that optimizing the use of all energy storage resources into the future is critical to our efforts to fully decarbonize the electric grid and maintain reliability on the system. The General Court recognized these issues with its passage of Chapter 179 of the Acts of 2022 (An Act Driving Clean Energy and Offshore Wind) and the Commonwealth is now poised to take the next critical step in that process. It is vital that this study capture the potential value that both new and existing mid- and long-duration storage can provide to the system with optimized usage.

Thank you for the opportunity to submit these comments for your consideration.