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TO:
Tom Ferguson, Ph.D.
Energy Storage Programs Manager, Renewable and Alternative Energy Division
Massachusetts Department of Energy Resources

RE: Mid- and Long-Duration Energy Storage Strategy Study

Dear Dr. Ferguson,

Please accept these comments on the Mid- and Long-Duration Energy Storage Strategy Study.

I lead the UMass Energy Policy and Rivers group, part of the UMass Energy Geographies and Politics Project. The UMass Energy Geographies and Politics Project consists of professors, student researchers, and alumni who work on electricity policy, markets, politics, sustainability, and environmental justice. The UMass Energy Policy and Rivers group brings special expertise on energy markets and policies related to hydropower and rivers, and related river and community impacts, policy, and regulatory processes. In the Energy Policy and Rivers group I also work with a river NGO advisory group who help guide on issues and interface with clean energy policy in Massachusetts and beyond.

I attended the second stakeholder session, reviewed the enabling legislation, commented on and read the RFP, and read the written comments that came in during the development of the RFP. Having seen the August presentation to stakeholders, my comments in this document are not primarily on the study thus far but rather the policy implications to come. In addition to broad comments on policy coming out of the E3 presentation, I have specific concerns about recommendations in relation to pumped-hydro storage. By extension, I offer some thoughts on how the Commonwealth could begin to weigh and approach the broader environmental, social justice, and cost considerations of various storage technologies and their alternatives. Finally, I added a section reiterating some key points that Regine Spector and I made in our comments on the Study as you were developing your RFP, considerations that are unfortunately absent from this study thus far.

A. General policy implications from the storage study.

1. The data and graphs presented by E3 show very clearly that medium- and long-duration storage have a strong role to play in a future energy transition and grid for Massachusetts and New England. The ability to reduce net peak load on the system from a predicted 50 GW or so to something more like 30 GW would be a major benefit to the region and the climate. This is good news in comparison to the Clean Energy and Climate Plan for 2030, which, as your RFP notes, "did not call for deployment of mid- and long-duration storage and rather models the New England region as relying on continued usage of natural gas-fired generation for firming and balancing applications." ***The Commonwealth and New England will be well-served by carefully crafted regulations, investments, and/or incentives related to medium- and long-duration storage.***

2. The consultants note that during winter reliability events when wind and solar are low for over a week, storage may need to be charged with fossil fuels. Given the fact that all storage is a net consumer of electricity, it will be important for the consultants to calculate what the net GHG emissions would be if storage is deployed during such periods (obviously it will depend on the efficiency of different technologies—and, as the consultants point out, the existing grid context), versus the business-as-usual option we have now of occasional very dirty, and problematic in terms of EJ, peaker plants being brought on line. ***Any kind of incentive program from the Commonwealth related to the use of storage for winter reliability must have the ability to provide nuance that will result in the lowest possible GHG emissions and EJ (especially health) impacts from peaker plants under different weather scenarios, grid contexts, and storage technologies.*** Existing policies like the RPS (clean peak) and PPA procurements might not be able to have that nuance without significant modification. This may be a context in which DOER, the Massachusetts AG's office, and NESCOE need to work carefully with NEPOOL and ISO for market changes (e.g. a carbon price); or it may be a context where markets simply will not give an adequate signal, and DOER and DPU should consider a regulatory approach, perhaps paired with procurements. More on this below.

3. In the stakeholder session Q&A, E3 made a very interesting observation: in their models, load flexibility could play the same role as storage. The policy implication is clear: ***the Commonwealth should find ways to incentivize load flexibility even more than storage, whether with similar instruments or entirely new ones.*** Load flexibility should come first over storage because: a) it does not cost additional net electricity consumption; and b) it will reduce the overall environmental and social impact because it generally requires less resource-intensive deployment of infrastructure or operational impacts compared to storage. Among load flexibility goals, one key one should be ***demand reduction***. This is different from efficiency and conservation and needs to be much more firmly and widely supported by the Commonwealth, as it has wide environmental and social benefits beyond GHG reduction.

4. The study suggests clearly that there may be justification for at least three kinds of storage incentives:
   - Procurements for new storage technologies and infrastructures of varying durations (medium, long, and longer) that could not otherwise get into operation, to cover their initial capital and other costs. The consultants and DOER should make sure, however, that any ratepayer-subsidized procurements are actually needed. Given E3's analysis that different durations of storage will be needed in successive times and tranches, any procurements should be timed accordingly. (A colleague looked at the interconnection queue and suggests there is plenty of storage ready to come on line and incentives may not be needed? Is some of this medium or long duration?—perhaps what is still most needed is help with that queue, and regional transmission planning?)

   - Extending the clean peak standard to cover storage for more than 4 hours—again, *if* and *when* this is needed. ISO energy market price differentials are already doing a good job handsomely rewarding storage when it is especially valuable to the grid. The E3 study suggests these rewards may increase sharply without further incentives as off-shore wind is built (at least at first; see next bullet). (See section B of this document.)

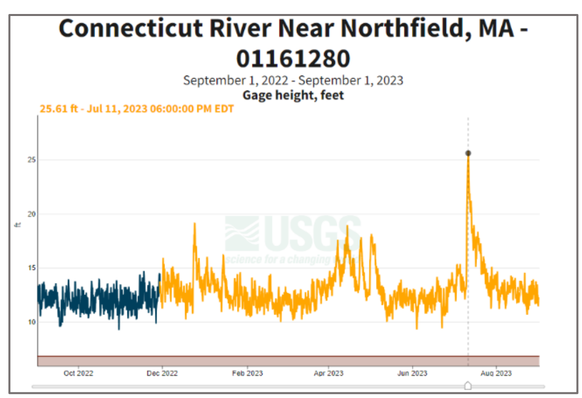
   - A storage capacity market beyond the existing ISO-NE capacity market. Based on the E3 August presentation, it appears that this may be especially important once each tranche of storage roles out (medium, then longer, then longer…) saturates the market, and prices diminish (including for regulation and reserves markets, etc.). At some point there may come a time that it is difficult for each duration of storage to earn enough to stay in operation. Given the critical importance of storage suggested by the E3 models during peak seasons and reliability events, the region will need to have excess storage capacity, for multiple durations of storage. A storage-specific capacity market (or perhaps an effective load carrying capability (ELCC) market??) may be the role of ISO-NE, not Massachusetts, but this study could be used to inform ISO-NE's deliberations on how to deal with storage.

B. Recommendations in relation to pumped-hydro storage, especially Northfield Mountain

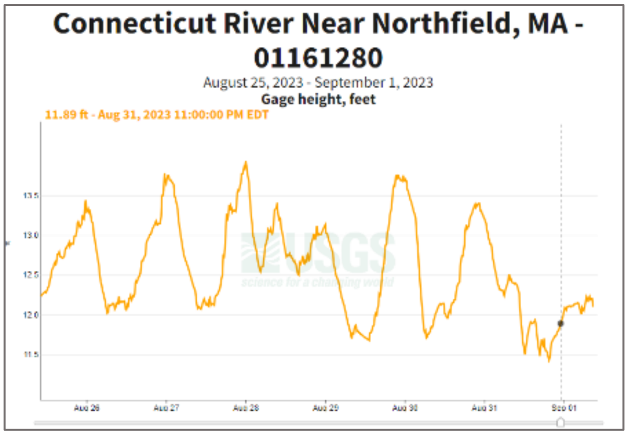
Background: Pumped-hydro storage and river fluctuations

E3's models suggest strongly that the largest existing supply of energy storage in New England, pumped hydro storage, is going to play an important role in the future of New England's energy grid and the energy transition. Both Northfield Mountain and Bear Swamp projects are rated as medium-term under the study definition (8 and 6 hours, respectively), although Northfield might qualify as long-term if its next license allows it to store additional water in its upper reservoir. Together they and the tiny Rocky River project in Connecticut provide about 1800 MW of pumped hydro storage capacity for the New England grid. This is only about 10% of what Massachusetts may eventually need according to E3's models, which means probably about 5% of the region's future needs. Based on this, these projects can certainly not solve the future supply and reliability problems; however, their contributions will be valuable for some time, especially on the early edge of offshore wind development, and continuing until the projected future when storage markets start to saturate. And even then, they may well be worth keeping on line for reliability events.

However, these open-loop pumped storage projects use Massachusetts rivers as their lower "reservoir," and because of this, they have profound environmental impacts. Every time they "charge" (pump) they suck up large volumes of river water, causing river levels to drop. They have the ability to suck up more water flow than the entire river sometimes provides. When this happens, from the downstream dam (Turners Falls) to the water intake, the river can flow backwards. In contrast, when the project generates energy, the opposite happens: water is poured into the middle of the river, river water levels rise dramatically, and the river from the intake to the upstream dam (Vernon Dam, farther away from the intake) can flow backwards. Under both the current and proposed license, pumping and generation at Northfield can cause water levels to fluctuate up to 9 vertical ft/day. Usual daily fluctuations are more like 4-5 feet. Understand that 9 vertical feet, even 4-5 feet, means a far greater horizontal distance, with water sometimes extending up the streambanks, other times not; this width is watered and dewatered repeatedly, day after day. These dramatic fluctuations in river flow, river level, and wetted or dry streambanks threaten higher temperatures and stranding for aquatic organisms in low-water places and times, cause displacement and disorientation during high-flow places and times, and contribute to riverbank and riverbed erosion.



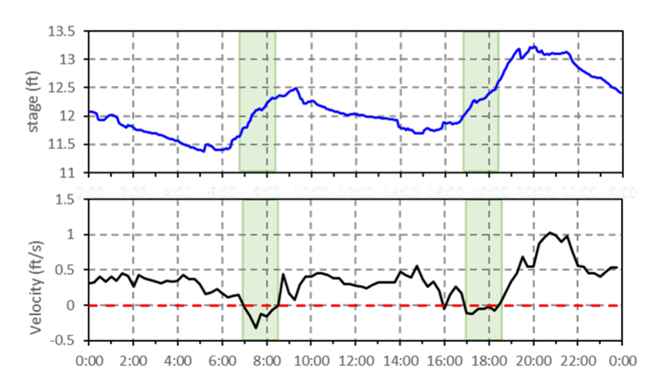
The graph to the right gives some sense of the fluctuations in water level over the last year, although this is about 9 river miles upriver from the Northfield intake / outflow, and not all the fluctuations shown here are caused by Northfield. The water level is shown varying from about 9 feet to about 26 feet. The highest levels, on July 11, correspond to this summer's floods. The daily fluctuations, however, are caused by "hydropeaking"— river flows that vary depending on hydropower production. The hydropeaking shown in this graph comes both from Northfield and several upriver projects, particularly Vernon Dam, the dam directly upstream on the Connecticut River.



A zoomed-in look at a relatively average few days, such as the last week (Aug 25-Sept 1, 2023, captured Sept 1 at about 9:30 AM), gives you some sense of more regular fluctuations. Here the river is going up and down over the course of a few days from 11.5 to 14 feet, so 2.5 vertical feet of variation. At the Northfield intake / outflow location downstream, this would be more extreme, likely closer to 5-6 feet in variance.

One situation when you can directly see the effect of Northfield, even at the USGS gage 9 miles upriver, is when the velocity actually goes negative at the same time the river level ("stage") goes up. Hydropeaking from the upstream Vernon Dam would cause stage *and* velocity to increase, so this increased stage with *negative* velocity is the effect of Northfield overpowering whatever flow is coming out from Vernon. High generation from Northfield has made the river flow backwards for miles, all the way up to the USGS gage.

Nov 3, 2022 - Green bars highlight periods when stage is increasing at Northfield gauge, and velocity is negative.



Beginning with the new license (expected 2024 or 2025) and increasing over the next few decades, Northfield Mountain is likely to cause greater, longer, and more frequent fluctuations in water flow and level in the Connecticut River.

This is because:

(a) The proposed license would allow a larger volume of upper-reservoir storage. The upper reservoir is the artificial lake built on top of Northfield Mountain, that holds the water the Northfield project pumps up from the river, and then later releases. The volume that FirstLight is allowed to store in the upper reservoir is the maximum amount of water the project can store and then release. More upper-reservoir storage will mean an increased length of time Northfield can generate from stored water—extending the current 8 hours it can run at its full capacity to a longer duration, likely exceeding the 10 hours needed to be defined as "long duration" storage under this Study's definitions. At the same time, the physical-hydrological analog of this greater energy storage duration is longer durations of both pumping and release flows, i.e. greater fluctuations in river levels (as well as upper-reservoir levels).

(b) As E3 show, once variable generation like wind and solar become a larger part of the grid, especially off-shore wind, greater variability in ISO market prices will incentivize increased use of storage. Northfield uses about 30% more energy from the grid than it produces so it needs about a 30% price differential to be able to store and release profitably. As the daily price highs and lows become more extreme, Northfield may well end up either pumping or generating most hours of the day in the summer and winter, when E3 models show demand and supply with significantly different timing in daily peaks. This means greater and more frequent fluctuations in river levels.

(c) Regulatory and legislative initiatives in New England states to incentivize energy storage beyond the ISO markets, including the Massachusetts Mid- and Long-Duration Energy Storage Strategy Study, could result in additional incentives for FirstLight to operate Northfield a larger number of hours outside of when it is profitable under the current ISO market structure. If so, these state-based initiatives will extend this hydropeaking further.

FirstLight's commissioned Energyzt 2020 study: A critique

In a 2020 study commissioned by FirstLight, "Northfield Mountain Pumped Storage: Assessment of Contract Benefits in an Increasingly Renewable Region," Energyzt Advisors, LLC, argued that "if Northfield is contracted to provide a guaranteed amount of energy into the day-ahead energy market during high-priced hours each day as opposed to operating as a merchant plant," the region would benefit from carbon emissions reductions, peak price shaving and reductions in cost to load, improved energy security during the winter months, and fast-ramp capability that increasingly will be required for reliability.

More recently, FirstLight quoted that study in its written comments as you were developing the RFP for the Mid- and Long-Duration Energy Storage Strategy Study, saying: "In a study published by Energyzt, LLC in June 2020 (included below), the firm concluded that operating just two of Northfield Mountain's four units more frequently would produce more than $410 million in consumer savings between 2022 and 2030. Additionally the same regimen would reduce carbon emissions by an average of 180,000 metric tonnes annually."

It appears from the study and these comments that FirstLight is poised to recommend that the Commonwealth consider a PPA procurement for Northfield to enter noncompetitive bids into the ISO-NE day-ahead market, 365 days/year. Because this is based on the Energyzt study, it is worth taking a moment to review the study.

Simply put, the Energyzt Study is based on several flawed assumptions, suspect inferences, and incorrect conclusions. Here is a summary of some of the problems in this report. I am happy to detail more if needed.

1. The Energyzt report states that the Northfield capacity factor is 8 percent, suggesting that this is terribly low. However, given the fact that Northfield needs to pump for approximately 12 hours at full power to generate approximately 8 hours at full power (its longest duration at full capacity), its maximum possible capacity factor is about 40%. A low capacity factor is normal for storage. (Hence, presumably, E3's use of ELCC instead of capacity factor.) Indeed, the EIA says that capacity factors for pumped storage around the country range from about 8% to 17%. The same EIA page shows that use of pumped hydro storage is especially low in the spring and fall when demand is generally less. Northfield is on the lower end of this range not because something is wrong, but because on the

New England grid, we rely on gas as our marginal resource most of the time. Much of the time the marginal resource at both low and high price points of the day is gas, and hence the price differential that would make it economical for Northfield to operate simply isn't there. That also means, however, that the most cost-effective resource to generate is not pumped hydro.

2. The Energyzt report states that having Northfield bid into the day-ahead market more, even outside of ISO energy market signals, will lower GHG emissions, and also improve system reliability and security. This is highly unlikely. Of course bidding into the DA market would not necessarily change anything about actual energy use (see #4). But if it did result in changed use out of energy market signals, using Northfield more will not produce more wind or solar energy. Those are currently limited by their absolute volumes on the grid; and their growth—especially that of off-shore wind, which as E3 shows will be the game-changer for the region, is slowed by other factors, like siting, transmission, and interconnection delays. It is likely true that if Northfield consumed more energy during low-demand hours, that a larger portion of that consumed grid energy would be nuclear energy, since in lower-demand times the steady supply of nuclear is a larger portion of the total. But even at those times, the marginal resource is usually gas—and thus it would be gas that would need to be burned in greater amounts to generate the power that Northfield would consume. Then, at the higher demand times when Northfield generated outside of ISO market signals, Northfield would displace mainly… gas generation. Perhaps Northfield would displace somewhat less GHG-intensive gas while using more GHG-intensive gas. But, it would consume about 30% more energy than it produced while it did this. The net result will not benefit GHG emissions.

   There are of course times when Northfield is an incredibly important resource that can displace very high GHG emitting resources like oil. But, those resources are expensive, and Northfield already gets strong market signals to perform at such times. Northfield additionally can provide fast reactions, pumping or generating in a matter of minutes, to stabilize the grid. Both strengths were in evidence, for example, on December 24, 2022, when there was a scarcity event. As FirstLight's CEO exclaimed proudly, Northfield (and other hydro) was a significant contributor to providing reliability—and probably displaced some of the oil that might have been burned. There is no public reporting on the revenues generated by such events but an ISO-NE report on the event shows that energy and ancillary market prices spiked steeply. It is likely that FirstLight earned millions of dollars in a few hours on that single day; existing ISO-NE market signals did their work well.

   When in the future there is ample off-shore wind on the grid, daily low and high prices will diverge. Then, Northfield will operate more—based on ISO market signals, fulfilling exactly the role that the Energyzt report extols. It does not need a Massachusetts contract to do this.

3. The Energyzt report claims that having Northfield bid into the Day-Ahead market outside of ISO market signals will also decrease cost to load and therefore energy cost to the region. This would seem to assume that Northfield will bid low enough into the DA market that it will shift the marginal resource on the grid during the times Northfield is generating. However, this does not take into account the cost of the contract to pay Northfield to do this, which should be subtracted from any cost that benefits the region. It should also be noted that if this actually worked, Energyzt is proposing that Massachusetts ratepayers subsidize those of the other five New England states. The claim also does not take into account the real-time market, when settlement happens—and which might be distorted by Northfield's out-of-market bids and operation. Finally, it does not take into account the fact that if this worked, it would be distorting the competitive energy market to lower prices at times of supply scarcity, when otherwise higher prices should signal a reduction in

consumption. There is a risk of actually increasing consumption because of this distortion. In short, there is a reason that Northfield should not operate when it's not able to do so according to the ISO energy markets: it's not getting the price signal it needs because there is another resource on the grid that can operate more cost-effectively. Massachusetts ratepayers should not pay it to do otherwise.

Policy implications: Pumped hydro storage

In terms of the three policy implications described in Part A, the above analyses suggest:

- There is no justification for a PPA procurement for pumped storage hydropower. It should be noted that this also applies to the suggestion in FirstLight's comments to you as you were developing the study that, "we recommend that Massachusetts closely examine pairing the operation of existing grid-connected energy storage with large-scale offshore wind projects. Such a pairing will enable the Commonwealth to deliver offshore wind when the region, the system and consumers need it most, not limited to periods when the wind is blowing.… [T]here are already more than 1,800 MW of installed energy storage resources capable of pairing with offshore wind facilities the moment the wind generation comes online." Yes, that storage is capable and ready, and will be highly useful once the off-shore wind comes on line. It will be signaled appropriately by ISO-NE energy markets and financially rewarded to extend out the timeframe when that wind benefits the region. Subsidizing pumped storage hydropower further with a contract, however, will neither speed up the wind installation nor improve its use. And, it would mean the Commonwealth's ratepayers would be paying for the same wind twice: once from the wind energy procurements and again when a pumped storage hydro facility is paid to store that wind.
- The clean peak standard will only apply to pumped storage hydro if Northfield is permitted to expand its upper reservoir and the Commonwealth considers this "incremental." If part of what comes out of this study is that the clean peak standard is expanded so longer-duration storage becomes more valuable, DOER should carefully analyze whether this will incentivize greater pumping and generation at Northfield. If so, ***Northfield should be required to fully mitigate—offsite if necessary—the incremental environmental harm to the river.*** If this is too difficult for DOER to add to its policies, then Northfield could be required to pay a percent fee that could become a fund for mitigation.
- The ISO-NE capacity market functions to help keep relatively low-earning generation projects that are necessary for occasional generation on line. Once off-shore wind comes on line, pumped storage hydropower is expected to become high earning. For now though, and in the more distant future once other storage is developed, it is important for Northfield to continue to earn revenue from the capacity market to stay on line for the times it is truly needed. Based on its relicensing applications, Northfield gets ample profit to stay in business for the foreseeable future, although its revenue from the capacity market is expected to decrease. There may be a justification at some point for a storage capacity market to supplement the existing capacity market.

Expanding out more broadly, this view of pumped storage hydropower shows that not only the deployment of this storage technology, but also its changing operational use, has significant environmental impacts. I have not even touched on it above, but changing operations, their environmental impacts, and the financial repercussions, also have broad social impacts: impacts on Native American groups with cultural and historic resources, recreational users, fishers—including fishers up and down the river who supplement their food security with migratory fish that pass through the

Northfield portion of the Connecticut River, the erosion of riverside property owners' lands, access to the river and riverbanks, fiscal implications for local towns, and more. If Massachusetts policy subsidizes increased use of storage, it is subsidizing impacts on all of these. This is of course while your sister agencies are spending other state resident dollars to protect these resources and users.

For this reason, if Massachusetts is to provide incentives for storage, these impacts need to be accounted for in your calculations, your analyses, and your policy. (See also below.)

C. Broader implications: Recommendations

The analysis above about pumped storage hydropower and Northfield in particular point towards ways the Commonwealth could begin to weigh and approach the broader environmental, social justice, and cost considerations of various storage technologies and their alternatives. No storage technology has zero impact, any more than does any generation.

To ensure benefit to the Commonwealth, MassCEC, DOER, and EEA must consider ecosystem impacts and environmental justice implications of all storage options, and include input from stakeholders from local communities. Different technologies have different impacts on local environments and communities. It is crucial that the study develop a list of potential technologies and likely *locations* for development or changed use, provide that information to local stakeholders and EJ groups, and hold hearings that are both local (accessible in person) and have remote options.

These significant "costs" (and some benefits) are not included in traditional economic analysis and should be included in the study report—much as I have begun to do above for pumped storage hydropower at Northfield Mountain. These kinds of interconnections were well recognized in the 2022 Act's provisions on wind energy. These must inform the policies that come out of the report as well.

D. Other general points absent from the storage study.

This section reiterates a couple points not covered above that Regine Spector and I made in our comments on the Study as you were developing your RFP, considerations that are unfortunately absent from this study thus far.

1. The study must consider new and diverse storage technologies and alternatives, not only medium and long-term energy storage. As the now 6-year-old State of Charge report showed, there are many new technologies that offer a wide range of storage options. Additionally, other technologies such as demand response, conservation, and distributed storage (e.g. car batteries) may provide some of the benefits of large-scale and medium- and long-duration storage. Many of these technologies will become even more beneficial in a future of potentially dramatic growth in availability of smaller-scale and distributed energy such as electric cars, busses and transport vehicles, battery walls, and smart grid-enabled metering and price signals. A narrower study focusing on current options and medium- and long-term storage risks recommendations that will keep existing long- and medium-duration storage, which are primarily pumped storage facilities that have dramatically changed the Connecticut and Deerfield Rivers, artificially competitive, possibly obstructing more creative and resilient decarbonization pathways.

2. Overall the goals of this study, and any policy that arises from it, should be:
    1. Contribute to rapid decarbonization in Massachusetts and beyond
    2. Limit over all ecological and social-justice impacts, in Massachusetts and beyond
    3. Limit long-term ratepayer and taxpayer cost
    4. Make tradeoffs visible and comprehensible, and provide for robust participation, to democratize the energy transition
    5. Ensure that expenditures of ratepayers or taxpayers through storage incentives are accountable to public purposes over time
    6. Support other energy system goals including resilience (which may be achieved e.g. through diversification and the development of distributed energy)
    7. Allow for "adaptive management," i.e. changing programs and incentives as technologies, grids, and other factors change

Thank you so much for all your thoughtful care and attention to this Study, and to the Commonwealth.

Sincerely,

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