Connecticut River Conservancy

Clean water. Healthy habitat. Thriving communities.

15 Bank Row, Greenfield, MA 01301
413.772.2020 · www.ctriver.org

April 24, 2020

Honorable Kimberly D. Bose Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Wilder Dam Project No. 1892
Bellows Falls Project No. 1855
Vernon Dam Project No. 1904
Turners Falls Project No. 1889
Northfield Mountain Project No. 2485

Connecticut River Conservancy submits battery storage analysis information in support of operational changes

Dear Secretary Bose,

The Connecticut River Watershed Council, Inc. (CRWC), now doing business as the Connecticut River Conservancy (CRC) is a nonprofit citizen group established in 1952 to advocate for the protection, restoration, and sustainable use of the Connecticut River and its four-state watershed. We have been participating in the relicensing of the five hydropower facilities on the Connecticut River since the beginning of the process in late 2012.

Earlier in 2020, CRC commissioned Synapse Energy Economics to look into the economic feasibility of transitioning Vernon Dam to a run-of-river facility paired with battery storage to capture some of the peak energy prices while allowing for operational changes to minimize daily surface water fluctuations. Similarly, in late 2019, a team of Dartmouth engineering students looked at the potential of adding battery storage to all three facilities in VT and NH. CRC has enclosed the results of both of these analyses.

Attached are:

1. Battery Storage Feasibility Study for Hydroelectric Plants at Wilder, Bellows Falls, and Vernon. Thayer School of Engineering at Dartmouth
2. Battery Storage and Hydro Power: Storage Options for Run-of-River Hydro for Vernon. Synapse Energy Economics

CRC is submitting the attached to be included in the record for consideration of operational alternatives. Run-of-river is widely accepted as a preferred alternative to meet Water Quality Standards and is routinely set as an operational requirement. The attached studies illustrate that run-of-river operation for these facilities is reasonable and feasible (40 C.F.R. § 1502.14).

We hope that these are useful to FERC in considering options going forward for all five facilities referenced in this letter that are currently undergoing relicensing. CRC has limited resources to provide research and development such as this, but feel that it is worthy of additional analysis. CRC would be interested in a more comprehensive analysis that examines all four dams and the pump station to ascertain if integration of advanced battery storage provides an alternative to enable additional operational changes.

This information has also been shared with Great River Hydro and FirstLight for their consideration. We have included that communication below.

Sincerely,

Kathy Urffer
River Steward, VT/NH
kurffer@ctriver.org
(802) 258-0413

Andrea F. Donlon
River Steward, MA
adonlon@ctriver.org
(413) 772-2020 x205

Attachments:

- Battery Storage Feasibility Study for Hydroelectric Plants at Wilder, Bellows Falls, and Vernon. Thayer School of Engineering at Dartmouth
- Battery Storage and Hydro Power: Storage Options for Run-of-River Hydro for Vernon. Synapse Energy Economics
- Email communication to Great River Hydro dated March 23, 2020
- Email communication to FirstLight dated March 25, 2020

Battery Storage and Hydro Power

Storage Options for Run-of-River Hydro for Vernon

Prepared for the Connecticut River Conservancy

February 4, 2020

AUTHORS

David White, PhD
Max Chang
Caitlin Odem

Synapse
Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

1. INTRODUCTION

The Connecticut River Conservancy (CRC or the Conservancy) engaged Synapse Energy Economics (Synapse) to analyze the possibility of changing the currently cycling/peaking operation at the Vernon hydro facility (Vernon or the Facility) on the Connecticut River to true run-of-river mode[1]and quantify the addition of a hypothetical battery storage installation.

A change to true run-of-river operation would reduce energy and perhaps capacity market revenues for Great River Hydro, LLC, the owner of the Facility. Our estimates of the conversion of the Vernon hydro facility to true run-of-river operation would likely have only a moderate effect (3 to 10 percent reduction) on the energy market revenues, which currently represent about half of the current total plant revenues (or from 1 to 5% of the total plant revenue). We estimate that the other revenue streams for Vernon would likely remain much the same with the change in operations. We believe that the key consideration is the capacity revenue from the New England Forward Capacity Market (FCM), which represents the power generated on peak load hours. To maintain the plant's capacity values and thus capacity revenues, it may be necessary to relax true run-of-river operations at those times.

Our analysis also quantifies the addition of battery storage to Vernon. Battery storage has the potential to produce energy, capacity, and ancillary revenues that could make up for revenues lost due to switching to full run-of-river operations. A battery storage system at the Vernon site would provide additional capacity value and other revenues not dependent on the water flow. In addition, it would have an energy price arbitrage value based on the hourly differences in daily prices. That is, batteries could charge during periods of low energy prices, and then discharge and sell the stored energy when the prices are higher.

We estimate that currently a 10 MW, 2-hour battery storage system cost would range from $4.9 to $9.8 million. This would result in positive net revenues at the lower cost level but negative net revenues for the higher costs. Battery costs are trending downward, which will improve the economics of battery storage in the medium-term future (beyond 2025).

Finally, the change in operations would likely also result in a more natural riverine environment and produce ecological benefits for the Connecticut River Valley. This report does not investigate and discuss those benefits.[2]

[1] Where water outflow equals water inflow on a continuous manner.

[2] See: https://www.ctriver.org/our-work/making-hydropower-cleaner-and-greener/

2. Objectives

This report investigates the economic feasibility of battery storage for the Vernon peaking hydropower dam in the context of operating the plant in a true run-of-river mode. The specific goals are as follows:

- Evaluate the economic impacts of the Facility switching to full run-of-river mode.
- Update Synapse's 2018 evaluation of revenue projections for the Vernon dam that would encompass a 20-year energy storage project.[3] The update includes current projections of energy, capacity, and ancillary services revenue for the dam based on our understanding of current market rules.
- Consider battery storage alternatives to ensure revenue stability for the Vernon facility if it were converted to full run-of-the river operations. Synapse's analysis includes sequencing, sizing, and placement of energy storage alternatives. This includes a revenue impact analysis of 1, 2, and 4-hour battery storage of different sizes.
- Produce a survey of battery cost estimates based on public sources. Identify possible incentives and/or grants that may be available. We understand that the Vernon facility, located in Vermont, provides renewable credits in Massachusetts.
- Develop energy storage options relative to a "business-as-usual" operation of the Vernon dam to quantify revenues to be replaced by a battery storage alternative. This analysis provides a preliminary alternative framework of current dam operations in order to engage stakeholders and to serve as a pathway for future more detailed analyses on the remaining dams on the Connecticut River.

[3] Peterson, P., D. White. 2018. *Connecticut River Relicensing Revenue Findings: A review of current Federal Energy Regulatory Commission hydroelectric facilities filings*. Synapse Energy Economic, Inc.

3. HYDRO OPERATIONS

3.1. Vernon Characteristics

This analysis focuses on the Vernon facility on the Connecticut River in Southern Vermont. The findings for Vernon are generally applicable to similar hydro facilities, although the specifics will differ.

As a starting point for analysis, we incorporated data for the Vernon facility. The following table using data from Great River Hydro's relicensing application shows the *pro forma* revenues from energy production, capacity, and ancillary services, based on 2016 prices and 10-year average generation.[4]

Table 1. Valuation of the annual output of the Vernon

Revenue Source	Value	Percent
On-peak Energy	$2,680,181	29%
Off-peak Energy	$2,264,803	25%
Forward capacity	$1,953,600	21%
Real-time reserves	$259,478	3%
Volt-ampere-reactive support	$15,029	~0%
Renewable energy credits	$2,020,000	22%
Total value	$9,193,091	100%

Capacity (based on 2017 CELT) (MW)	**32.0**
Generation (MWh) [5]	162,557
Capacity factor	**58.0%**

Source: Calculated by Synapse using 2016 Federal Energy Regulatory Commission (FERC) and ISO-NE data.

Although the facility's total revenue per MWh of output was $56.55/MWh ($9,193,091 ÷ 162,557 MWh). The energy revenues only represented a little more than half of that, or $30.42/MWh ($4,944,984 ÷ 162,557 MWh). For comparison, the ISO-NE all-hours market energy price in 2016 was $29.62/MWh[6] which gives a very modest premium of 3 percent. Thus, the dam's energy revenue premium associated with the timing of the plant's generation appears to be fairly modest. We note that Vernon's capacity factor (actual generation divided by maximum possible generation) is fairly high at 58 percent. We observe that the facility's off-peak energy revenues are close to those of on-peak revenues.

[4] Vernon Final FERC Application, Appendix D, Table D-1, page D-3. May 1, 2017. All Great Hydro Relicensing documents for Vernon are available here: http://www.greatriverhydro-relicensing.com/overview/documents/. We also note that the 2016 energy prices used in this valuation table were 36% lower than the average for 2010-2016.

[5] Nine-year average generation. Vernon Final FERC Application, Appendix B, Section B2.1, page B-4. May 1, 2017.

[6] ISO New England (ISO-NE) is the independent system operator for New England. These are its 2016 locational (day-ahead) market prices. Available at https://www.iso-ne.com/markets-operations/iso-express. Energy prices were at a low in 2016 and increased to $33.0/MWh in 2017 and to $43.6/MWh in 2018.

These factors suggest the plant is really more of an intermediate or cycling, rather than a peaking, facility. In other words, the plant generally runs over many hours in the course of a day and not just during the highest priced periods

Vernon also has substantial renewable energy payments resulting from the 2008 installation of new replacement turbines that provide an additional 16 MW of total capacity. That Generation uprate was eligible for Massachusetts RPS Class II Renewable Generation Energy Certificates (RECs). In 2016, the RECs from the 16 MW of incremental generation were worth $25 per MWh. This will likely decrease in the future, but by how much is uncertain. The 2018 AESC report for example projects these REC prices to decline to about $6 per MWh in 2025.[7] In addition, the older existing turbines became eligible for Tier 1 of the Vermont Renewable Energy Standard (RES) in 2017. These credits are currently valued at about $10/MWh— equivalent to another $800,000 per year.

Vernon does not operate independently but is rather part of a jointly managed system that includes the Fifteen Miles Falls Project[8] followed down river by the Wilder, Bellows Falls, and Vernon facilities.[9] As stated in the Vernon pre-application filing:

> The Project is operated in conjunction with other TransCanada hydroelectric generating facilities on the Connecticut River, in a coordinated manner hydrologically, that takes into consideration variations in demand for electricity as well as natural flow variations due to seasonal snow-melt or precipitation events that occur within the Connecticut River watershed. [10]

Although Vernon has a reservoir, the effective storage capacity of this reservoir is only about 10 hours at full generation, which limits timing flexibility even on a daily basis.[11] The joint operation constrains the operation of the individual facilities and also complicates what is meant by run-of-river. The river flow coming into Vernon is determined by the operation of the upstream dams and thus not truly natural. There are a number of ways that the run-of-river criteria could be defined (1) outflows matching inflows in a given hour, (2) uniform flow over a 24-hour period, (3) stable reservoir elevation, or something else? We believe those are issues to be explored and to be worked out in any future agreement regarding the Connecticut River.

---

[7] Table 58, "Avoided Energy Supply Components in New England: 2018 Report", Synapse Energy Economics, October 24, 2018. https://www.synapse-energy.com/project/aesc-2018-materials

[8] The Fifteen Miles Falls Project includes the Comerford, Moore and McIndoes Falls sites with both generation and considerable storage capacity.

[9] Vernon Pre-Application FERC filing, Table 2.5-1 Connecticut River operations summary, page 2--29. Oct 30, 2012. In 2017, Great River Hydro, LLC acquired all of TransCanada Hydro Northeast assets that include the four hydro facilities.

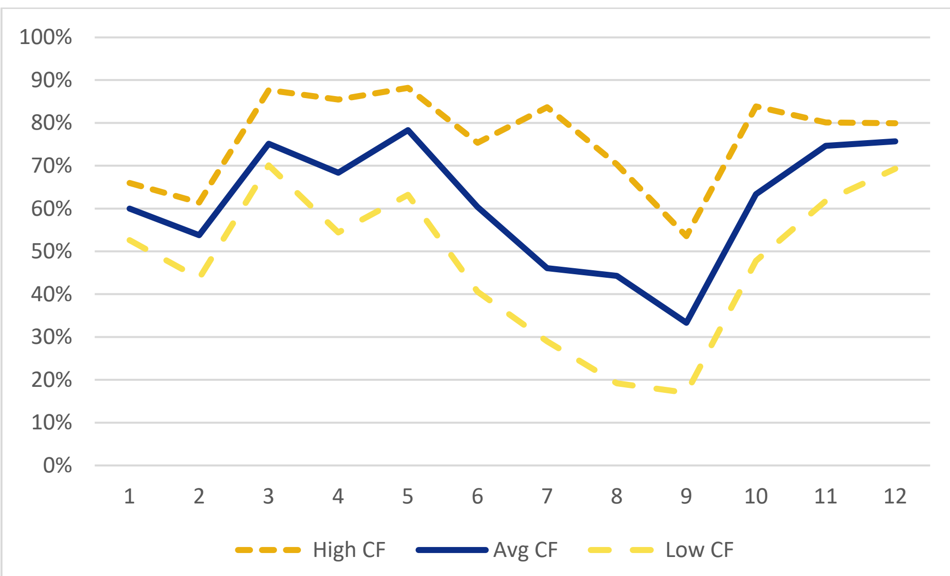
[10] Ibid, page 2--28.

[11] Derived from Vernon Pre-Application FERC filing, Table 2.1-1 Project Summary, page 2-4 and Table 2.5-2 Project Discharge Capacity, page 2-32. Oct 30, 2012.

3.2. Energy Revenue

As a general matter, the energy generation of a hydroelectric plant is dependent on river flow, which varies substantially on many scales: hourly, daily, monthly and annually. Over the period from 2008 through 2012 after the installation of the new turbines, the Vernon annual capacity factors varied from 57 to 69 percent. The monthly variations can be even more substantial as shown in Figure 1. While we do not have the hourly or daily generation data, the high capacity factors lead us to believe the monthly variations may be the limiting factor for true peaking operation for much of the year. While the lowest priced hours might be avoided, in many months Vernon will be generating energy for most hours of many days. In addition, there are minimum flow requirements that require operation in even during the lowest priced hours. The following figure shows that capacity factors are high in the spring and late fall; they are lower in mid-winter (January and February) and lowest in summer and early fall. These generally mirror seasonal river flows. Even the lowest monthly capacity factor of 30 percent represents at least seven hours of generation.

Figure 1. Vernon historical monthly capacity factors (2008–2012)



Source: Calculated by Synapse using FERC filing generation data.

As stated before, the Vernon facility is operating in more of a cycling than a peaking mode. But if it were converted to true run-of-river (inflow = outflow for any given hour), we would expect some loss of energy revenues. Using the above monthly average capacity factors and the 2018 hourly energy prices, we have conducted an initial calculation of what that penalty might be. Based on public data, we estimate that Vernon's energy revenue loss associated with true run-of-river operation could be as much as 10 percent, although a number of operational factors that limit operational flexibility might lower that impact. For example, the minimum flow of 1,250 cubic feet per second (cfs) required in the existing license (roughly equivalent to about 2 MW) would limit the ability to fully maximize energy revenues.[12] Based on the FERC filing materials for 2016, that penalty value looks closer to 3 percent. We also reviewed a report from the University of Massachusetts, that looked at the benefits of flexible generation versus an inflow-equals-outflow (IEO) policy that is equivalent to run-of-river.[13] The UMass study showed a penalty of 6.4 percent for IEO operation looking at the top 10 percent of energy prices.[14] Another UMass study calculated the IEO penalty to be 1.9 percent for Vernon.[15] The precise economic impacts will depend on the specifics of a run-of-river plan that is implemented for that section of the river, but the effects on energy revenues appear to be modest. One could conduct a more detailed and comprehensive analysis with data available to Great River Hydro.

3.3. Capacity Revenue

In the 2016 FERC filing, Vernon's capacity was rated at 32 MW. In the most recent ISO-NE Capacity, Energy, Loads, and Transmission (CELT) report, the effective capacity for the facility has been upgraded to 34.9 MW, about 9 percent.[16] This translates to more capacity revenue. For 2019, this represents capacity payments of approximately $3.6 million, which is considerably above the 2016 payments of $1.9 million in Table 1. Capacity prices vary from year to year, and payments will be $2.6 million in 2020 based on forward capacity auction results.

The proposed change in dam operation to run-of-river would mean that the dam's capacity rating would be based on the five-year average performance. This impacts the amount of future capacity revenue since ISO-NE's categorization of generators directly affects how and what amount they are paid for capacity. A full run-of-river operational mode would likely result in a reduced capacity value and revenues. However, a modified run-of-river mode allowing for greater generation during times of peak demand might result in minimal impact on capacity values and revenue. This is something that needs exploration with the dam operator and ISO-NE. It would be a material change for Great River and something new for ISO-NE.

---

[12] Vernon Pre-Application FERC filing, Table 2.1-1 Project Summary, page 2-4. Oct 30, 2012.

[13] S. Pfeifle, R. Lotter and R. Palmer. 2019. "Investigating the Integration of Flexibility into Dam Operation Planning," University of Massuchetts at Amherst.

[14] Id., Figure 1.

[15] T. Chatty, S. Gachuhi, E. Stoikou and M. Laser, 2019. "Battery Storage Feasibility Study for Hydroelectric Plants."

[16] See ISO-NE 2019 Capacity, Energy, Loads, and Transmission (CELT) Report, https://www.iso-ne.com/system-planning/system-plans-studies/celt The Plant capacity can be measured in a number of ways, the nameplate or design capacity being one of those. The CELT capacity is based on what can be delivered in specified peak demand hours.

3.4. Renewable Energy Credit Revenue

The renewable energy credits generated by the dam, which are substantial, do not depend on the timing of the generation and thus would not be affected by a change in the run-of-river operation. RECs are earned for every MWh of generation.

3.5. Other Revenues

We have identified two ancillary revenue streams in the FERC materials: real-time reserves and volt-ampere-reactive support. These revenue streams could be affected by switching to full run-of-river operations. The real-time reserve payments might be reduced if ramping is restricted.[17] There are likely minimal impacts on the very modest volt-ampere-reactive support payments.[18] Again, Great River Hydro would likely have the best sense of these effects.

3.6. Future Revenue Projections

Future revenues depend on many uncertain factors such as fuel prices, market structure, environmental requirements, and so forth. In our analysis, we first calculate the likely Vernon revenues in 2020, both as currently operated and in a hypothetical run-of river mode.

Table 2. Estimated 2020 hydro revenue forecast ($1,000)

Categories	Current Mode	Run-of-River Mode
Energy	$6,431	$5,932
Capacity	$2,696	$2,696
MA RPS	$2,280	$2,280
VT RPS	$929	$929
Other Services	$300	$300
Total Revenue	$12,637	$12,138
Difference		-$500

Note: From the Synapse workbook "Plant Revenue Projections Version 3.xlsx." A five-year average energy price of $36.4/MWh was used for the 2020 energy revenue calculations. We assume no change in Other Services revenue although that might change depending on the specific run-of-river mode. Calculated by Synapse using FERC and ISO-NE data.

[17] For specifics see: https://www.iso-ne.com/markets-operations/markets/reserves.

[18] For specifics see: https://www.iso-ne.com/markets-operations/markets/voltage-support/.

We then project those numbers forward at the inflation rate of 2 percent to give a reasonable forecast of future revenues.[19] For consistency we will use that same forecast to evaluate battery storage. This gives a comparable basis for evaluating the battery storage benefits. In a more thorough, but more time-consuming analysis, a range of forecasts could be considered.

Table 3. Projection of future hydro revenue (million nominal $)

Year	Current Mode	Run-of-River Mode	Difference
2020	$12.6	$12.1	-$0.50
2025	$14.0	$13.4	-$0.55
2030	$15.4	$14.8	-$0.61
2035	$17.0	$16.3	-$0.67
2040	$18.8	$18.0	-$0.74

Source: Calculated by Synapse using FERC and ISO-NE data.

In conclusion, our analysis shows that operating Vernon in true run-of-river mode would likely have only a modest effect (3–10 percent) on the 2020 annual energy revenues (approximately $500,000). This represents four percent of the plant's total revenues. More uncertainty exists around the capacity revenues. Those may require deviations from true run-of-river operations to generate at higher levels during periods of peak system demand.

[19] A more sophisticated approach could be considered, but there is always considerable uncertainty in long-range price forecasts.

4. BATTERY STORAGE BENEFITS

Battery storage's primary benefit is the ability to store electricity from times when it is readily available and cheap to times of high demand when it is more expensive. It also has the benefits of providing additional capacity and a variety of grid services to improve system operation.

4.1. Services from Battery Storage

Batteries provide the capability of storing electric energy and then providing it when it is more valuable. The following is the list of grid services provided by battery storage:

Capacity (resource adequacy)

The FERC governs wholesale energy markets and has recently focused its attention on the role of energy storage in wholesale power markets. In April of 2019, FERC approved revision to ISO NE's Market Rule 1, which governs the operation of New England's wholesale electricity markets and includes detailed information on pricing, scheduling, offering, bidding, settlement, and other procedures related to the purchase and sale of electricity.[20] The approved revision allows energy storage to participate in the real-time energy markets.[21] This revision follows FERC Order No. 841 issued February 18, 2018 requiring the removal of market barriers for electric storage in the capacity, energy, and ancillary service markets.[22] Any sizable stationary storage system is able to participate in the real-time energy market, provided the system has been approved through the ISO's interconnection process.

Resource adequacy is a term used in the electric industry that refers to the amount of installed capacity needed to meet the anticipated peak demand and the required reserve margin for electricity on a regional grid. In most regions with wholesale energy markets, capacity markets have been created to achieve resource adequacy goals.

Ancillary services

Ancillary services are critical services required by grid operators to ensure that the grid operates within the standards established by the regional reliability authority. In New England, the independent system operator for the region (ISO-NE) is tasked with controlling and operating the electric power system for all of New England. In addition, ISO-NE operates wholesale energy markets, including markets for several ancillary services.

---

[20] ISO New England. *Market Rule 1.* Available at: https://www.iso-ne.com/participate/rules-procedures/tariff/market-rule-1.

[21] Utility Dive. *FERC allows storage to access New England real-time energy markets*. March 2019. Available at: https://www.utilitydive.com/news/ferc-allows-storage-to-access-new-england-real-time-energy-markets/549436/.

[22] Federal Energy Regulatory Commission (FERC). *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*. Feb 15, 2018. Available at: https://www.ferc.gov/whats-new/comm-meet/2018/021518/E-1.pdf.

Frequency response regulation

ISO-NE defines regulation services as "the capability of specially equipped generators and other energy sources to increase or decrease output or consumption every four seconds."[23] Generators that participate in this market allow for their assets to be automatically controlled by the ISO-NE and instantaneously responsive to automated signals to balance variations in demand and system frequency. Generators providing this service have received payments ranging historically from $28 to $204 dollars per kilowatt per year in compensation through wholesale ancillary services markets.[24] The frequency response regulation market has been the most important market for grid-scale battery application. According to the U.S. Energy Information Administration (EIA), 88 percent of installed storage capacity in the United States was providing frequency regulation in 2016.[25] This service is most needed in locations with significant load variability.

Reserves

Reserves serve as insurance for grid operators in the case of an unexpected forced outage of a power plant or transmission facility. The reserve market in ISO-NE is broken into two segments: the forward reserve market and real-time reserve pricing.[26] The forward reserve market has two auctions, one for the summer and one for the winter. In the forward reserve market, the ISO is ensuring it has assets committed to providing insurance for grid operation and uses an auction to compensate generators for this service. The clearing price for the ISO-NE Summer Forward Reserve Auction for 2019 was $1,899/MW-Month[27] and the ISO-NE Winter Forward Reserve Auction for 2019–2020 was $799/MW-Month.[28] This means generators that have sold capacity in this market will be compensated per MW capacity they have committed to reserves on a monthly basis for the duration of the season. The generator then bids into the real-time energy market but can only bid at the pre-determined real-time reserve price for the capacity the generator has committed to the reserve market. It is possible for stationary storage systems to participate in this market. Furthermore, ISO-NE's current energy security proposal would restructure how this market works, potentially getting rid of the forward reserve market.[29]

---

[23] ISO-New England (ISO-NO). *Regulation Market.* Available at: https://www.iso-ne.com/markets-operations/markets/regulation-market.

[24] Rocky Mountain Institute (RMI). Technical Appendix A. Available at: https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_RMI-TheEconomicsOfBatteryEnergyStorage-Appendices.pdf.

[25] U.S. Energy Information Administration (EIA). *U.S. Battery Storage Market Trends*. May 2018. Available at: https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf.

[26] ISO-New England (ISO-NO). *Forward Reserve Market and Real-Time Reserve Pricing.* Available at: https://www.iso-ne.com/markets-operations/markets/reserves.

[27] ISO-New England (ISO-NO). *Forward Auction Summary.* Available at: https://www.iso-ne.com/static-assets/documents/2019/04/fr_auction_sum2019.pdf.

[28] ISO-New England (ISO-NO). *Forward Auction Summary.* Available at: https://www.iso-ne.com/static-assets/documents/2019/08/fr_auction_winter2019-20.pdf.

[29] ISO-New England (ISO-NO). *Energy-Security Improvements Key Project.* Available at: https://www.iso-ne.com/committees/key-projects/energy-security-improvements/.

Voltage support

Transmission and distribution lines require power support to enable electricity to continuously flow through the lines.[30] Voltage support takes the form of generators dispatching reactive power to the grid to ensure the voltage always stays within an acceptable range. When a generator dispatches reactive power, they cannot dispatch the same amount of real power into the energy market. Because the generator could lose money by providing the ISO with voltage support, they are contracted and compensated for the service provided.

Black start

Generators that provide black start services are tasked with the critical ability to restore power to the grid in a partial or complete outage of the system.[31] The ISO contracts and compensates generators with the ability to provide this service at strategic locations on the transmission and distribution system to help restore power. In order to participate in providing the ISO with black start services, generators must be able to dispatch power to the grid at the correct grid voltage with no assistance from the grid itself. Generators that meet this standard are contracted individually by the ISO to provide this service.[32] Black start generators are often fossil fuel resources, but battery storage also has the capability to provide this service to the grid with the correct configuration.

Transmission & distribution investment deferral

There is growing interest in using distributed energy resources as alternatives to upgrading transmission and distribution infrastructure, known as non-wires alternatives (NWAs) to traditional T&D investments. T&D investments can be extremely expensive and energy storage has been identified as an important technology for NWA to defer such investments.

Stationary storage has already been proven to be effective in deferring transmission and distribution upgrades.[33]

Wholesale energy arbitrage

Energy storage can participate in energy arbitrage at the wholesale level. Wholesale energy arbitrage involves the purchase of wholesale electricity at times and locations where the locational marginal price

[30] ISO-New England (ISO-NO). *Voltage Support.* Available at: https://www.iso-ne.com/markets-operations/markets/voltage-support.

[31] ISO-New England (ISO-NO). *Blackstart Service.* Available at: https://www.iso-ne.com/markets-operations/markets/black-start-service.

[32] ISO-New England (ISO-NO). *Billing, Settlements, and Tariff Reports.* Available at: https://www.iso-ne.com/isoexpress/web/reports/billing/-/tree/schedule-16---blackstart-standard-rate-report

[33] Perter Maloney. *Storage for T&D deferral works, Arizona Public Service finds in Tonto National Forest*. Utility Dive. November 2017. Available at: https://www.utilitydive.com/news/storage-for-td-deferral-works-arizona-public-service-finds-in-tonto-natio/511485/.

(LMP) of energy is low (typically during nighttime hours) and sale of electricity back to the wholesale market when and where LMPs are higher.[34]

4.2. Economic Benefits of Battery Storage

For this analysis we looked at the economic benefits of a grid-connected battery storage system located at the Vernon site. For the purposes of our analysis, we chose to quantify the benefits of a 10 MW utility-scale battery storage system.[35] We chose 10 MW for several reasons: (1) 10 MW is an easy quantity for calculations; (2) it represents the lower size end of a utility-scale system, (3) the anticipated revenues are comfortably more than what would be lost by true run-of-river operation at Vernon; and (4) a 10 MW system could be scaled incrementally. Battery storage at other locations and especially "behind the meter" would have additional benefits.

Table 4. Example battery storage configuration

Category	Value	Notes
Capacity rating	10 MW	Nominal
Storage capacity	20 MWh	2 hours
Charge/Discharge Efficiency	90 %	Lazard high end value
Energy revenue	$170,000 per year	Based on arbitrage of 2018 hourly prices
Capacity revenue	$773,000 per year	Based on 5-year average $77,259/MW
Ancillary revenue	$77,000 per year	Typical 10 percent of capacity revenues
Estimated total revenue	**$1,020,000 per year**	

Source: Calculated by Synapse using FERC and ISO-NE data.

The primary revenue stream is from the capacity market and is determined by the maximum power that can be delivered to the grid. Additional hours of storage capacity would increase the energy revenues but have little effect, beyond some minimum level, on the other revenue streams. In fact, there are diminishing energy arbitrage returns as the number of hours are expanded since the average price differences are reduced. The following table shows how that would vary with different storage levels. For example, additional storage duration would increase the total arbitrage revenues but at a lower net rate.

[34] RMI Storage Economics.https://rmi.org/wp-content/uploads/2017/03/RMI-TheEconomicsOfBatteryEnergyStorage-FullReport-FINAL.pdf.

[35] See also: U.S. Energy Information Administration (EIA). 2018. "The design and application of utility-scale battery storage varies by region," *Today in Energy*, February 28. https://www.eia.gov/todayinenergy/detail.php?id=35132.

Table 1. 2018 arbitrage value of energy storage

	Storage Capacity		
	1 Hour	2 Hour	4 Hour
Arbitrage Value ($/MWh)	$24.2	$23.0	$20.1

Source: Calculated from ISO-NE Vermont hourly prices for 2018.

Increasing the hourly storage capacity of the system shows only a modest revenue increase. Our 1-hour storage calculation assumes that the capacity and ancillary revenues are not affected by the lower storage duration, all of which depends on future ISO-NE market rules.

Table 2. Table 6 – 10 MW battery system revenue

	(Million Nominal $)	
Year	**1-Hr**	**2-Hr**
2020	$0.9	$1.0
2025	$1.0	$1.1
2030	$1.2	$1.3
2035	$1.3	$1.4
2040	$1.4	$1.5

Source: Calculated by Synapse using ISO-NE data.

However, it appears likely that two hours of storage capacity will be necessary for a resource to qualify for the capacity market. A proposed or existing storage device will be evaluated for capacity based upon maximum output over 2 hours if it is connected to the grid directly and is registered as an Energy Storage Facility. That is, as a Generator (capital G) it has the same audit period as any other generator.[36]

This economic analysis is based on current market conditions. However, there may be future changes. Specifically, the addition of more non-dispatchable wind and solar renewable energy to the New England system could increase the daily price range and also the arbitrage value of storage.

Additional hours of storage would provide additional energy arbitrage revenues but have little effect on the capacity revenues, which are substantially greater.

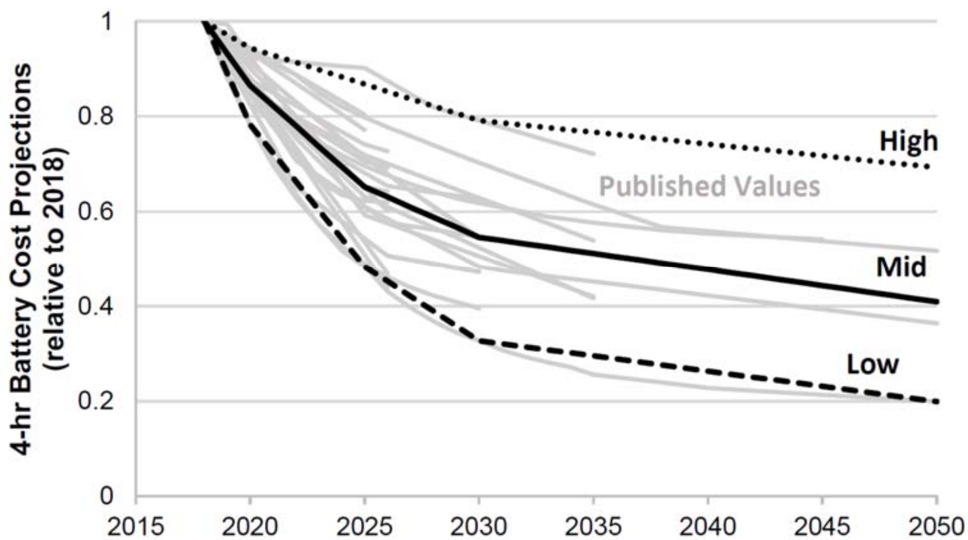
To summarize, our illustrative 10 MW (20 MWh) of battery storage could provide revenues in the NE-ISO markets of about 1 million dollars per year that would increase gradually over time.

[36] As per the FERC Compliance ruling. https://iso-ne.com/static-assets/documents/2019/11/er19-470-000_11_22_19_order_on_order_841_compliance_filing.pdf.

4.3. Battery Storage Costs

Initial costs can be substantial. However, battery storage costs have been undergoing a rapid decline. A recent study by NREL projects substantial future cost reductions.[37]

Figure 2. NREL battery cost projections



Source: NREL Report, Figure ES-1.

The key economic consideration is the lifetime cost. Storage lifetime costs, with low ongoing expenses, can be quite moderate. A recent analysis of the lifetime cost of storage was released by Lazard in November of 2019.[38]

Using the capital cost ranges on page 7 of the Lazard report, the capital cost for a 10 MW 1-hour battery storage system would range from $2.8 to $5.1 million, and the 2-hour storage costs would range from $4.9 to $9.8 million as detailed below.

But more relevant are the levelized costs on page 5 of that report which gives the 20-year Unsubsidized Levelized Cost of Storage Comparison – Capacity ($/kW-year). For a wholesale system (in front of the meter) the levelized cost (for 2-hour storage) ranges from $121 to $221 per kW-year. In our example, a 10 MW 2-hour storage facility translates to levelized costs of $1.2 to $2.2 million per year. The cost for a 1-hour system ranges from $66 to $114 per kW-year for levelized costs of $0.66 to $1.14 million per year. This shows a positive revenue margin for a system with a 1-hour storage capacity, assuming that

[37] Cole, W. and A. Frazier, "Cost Projections for Utility-Scale Battery Storage," National Renewable Energy Laboratory, June 2019.

[38] "Lazard's Levelized Cost of Storage Analysis – Version 5.0", November 2019, https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf.

full capacity-based revenues can be secured for the system. The net revenues are less for a two hour storage system, but still positive with the low cost estimate.

Table 7. 10 MW battery system levelized revenue and cost comparison (M$)

Category	1 Hour	2 Hour
Revenue	$1.41	$1.52
Cost - Low	$0.66	$1.21
Cost - High	$1.14	$2.21
Net Revenue		
Low Cost	$0.75	$0.31
High Cost	$0.27	-$0.69

Note: The revenues from a 10 MW 1-hour battery storage system roughly offset the revenue losses associated with run-of-river operation.

It is likely that the future cost of battery storage systems will decline as in the past. The 2019 Lazard Cost of Storage Analysis report says the following:

- *LCOS v5.0 reveals significant cost declines across most use cases, despite industry concern about rising costs for future deliveries of lithium-ion systems due to higher commodity pricing and challenges related to storage module availability.*
- *Observed cost declines have been most pronounced for lithium-ion technologies over the past year, while more limited cost improvements were observed in advanced lead and flow battery technologies.*
- *Cost declines were more pronounced for storage modules than for balance of system components or O&M.*
- *Year-over-year cost declines were less pronounced than those observed in LCOS v4.0, albeit there is notable variance between use cases (e.g., compared to LCOS v4.0, the rate of cost declines for Commercial & Industrial systems increased, while that of Wholesale systems decreased).*
- *The previously observed trend of growing cost disparity within use cases continued, as the gap between the lowest-and highest-cost systems increased, on a relative basis, vs. LCOS v4.0.*[39]

We also note a recent Dartmouth student study that looked at the battery storage feasibility for Wilder, Bellows Falls, and Vernon.[40] That study considered a range of battery technologies and had similar overall findings, although the energy arbitrage value they calculated was much less.

[39] "Lazard's Levelized Cost of Storage Analysis – Version 5.0", November 2019, https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf.

[40] T. Chatty, S. Gachuhi, E. Stoikou and M. Laser, "Battery Storage Feasibility Study for Hydroelectric Plants at Wilder, Bellows Falls and Vernon", Thayer School of Engineering at Dartmouth, 2019.

4.4. Battery Storage Incentives

Various incentives could reduce the cost of a battery storage system and thus improve the economics.

Although there are presently incentives for behind-the-meter battery storage, especially coupled with solar photovoltaic systems, our limited research did not identify any current incentives for independent grid-connected battery storage.

5. HYDROELECTRICITY AND BATTERY INTEGRATION

Any storage system installed at Vernon will likely require separate metering, especially if the storage system draws power from the grid for charging. There may however be some economies in sharing existing transmission lines. The details depend on the configuration and location and would have to be worked out on a site-specific basis.

When the batteries are being charged they can either use the hydro generation or draw power from the grid, or some combination. The value of the hydro generation and the cost of the grid purchases are the same based on the locational market price at that specific time. Other than possibly using some hydro generation to charge the batteries, there is little need for interaction between and integration of the two systems.[41]

[41] There might be efficiencies and economies in some situations of closer electrical and operational integration between the hydro generators and the battery storage system. That might be a case in the design of new solar or wind systems and integrated battery storage, but we are unable to find any hydroelectric examples.

6. CONCLUSIONS

The change of Vernon to true run-of-river operation would reduce energy, and perhaps capacity market revenues for Great River Hydro, LLC, the owner of the Facility, and Battery storage has the potential to produce both energy, capacity, and ancillary revenues that could make up for lost revenue from switching to full run-of-river operations. Our estimates of the conversion of the Vernon hydro facility to true run-of-river operation indicate only a moderate effect (3 to 10 percent) on the energy market revenues, which currently represent about half of the current total plant revenues. We estimate that the other revenue streams for Vernon would likely remain much the same with the change in operations. We believe that the key consideration is the capacity revenue from the New England Forward Capacity Market (FCM) representing the power generated on peak-load hours. To maintain the plant's capacity values and thus capacity revenues; it may be necessary to relax true run-of-river operations at those times.

Our analysis also quantifies the addition of battery storage to Vernon. As indicated above, battery storage has the potential to produce both energy, capacity, and ancillary revenues that could make up for lost revenue from switching to full run-of-river operations. A battery storage system at the Vernon site would provide additional capacity value and other revenues not dependent on the water flow. In addition, it would have an energy price arbitrage value based on the hourly differences in daily prices. Batteries could charge from Vernon's turbines during periods of low energy prices, and then discharge when energy prices are higher.

Current energy storage costs indicate that the value proposition for a 10 MW energy storage system would be economic at the lower range of costs, but likely would not be so at higher costs. However, we anticipate that energy storage costs will continue to decrease improving the economics of battery storage systems.

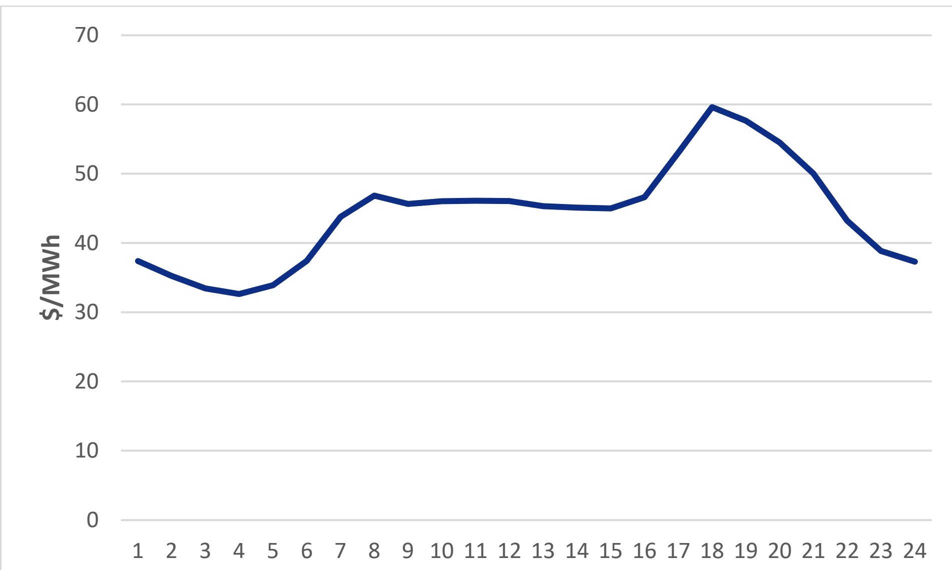
We estimate that currently a 10 MW, 2-hour battery storage system cost would range from $4.9 to $9.8 million. This would result in positive net revenues at the lower cost level but negative net revenues for the higher costs. The trend in battery cost is decreasing, which will improve the economics of battery storage in the medium-term future (beyond 2025).

APPENDICES

A. Energy Arbitrage

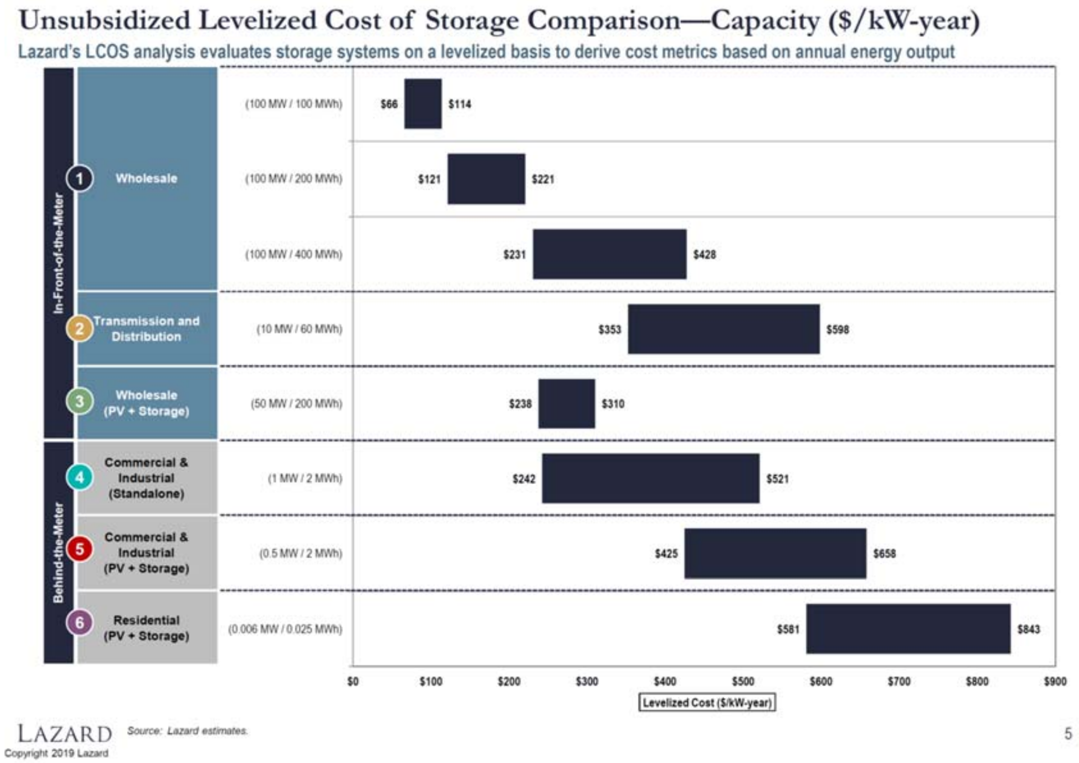
A battery storage system allows arbitrage of daily energy prices. The system can charge when prices are low and then discharge and sell the power when prices are higher. New England prices are generally lowest in the early hours of the morning and highest in the early evening, although the specifics vary from day to day. The following graph shows the hourly average Vermont energy prices for 2018. The low point was $32.6/MWh at 4 am and the highest priced hour was 6 pm at $59.6/MWh, for a difference of $27/MWh. A storage system operating at a 90 percent efficiency could thus achieve an average net revenue of about $24.3/MWh on a daily basis. For comparison the average energy price in 2018 was $44.2/MWh.

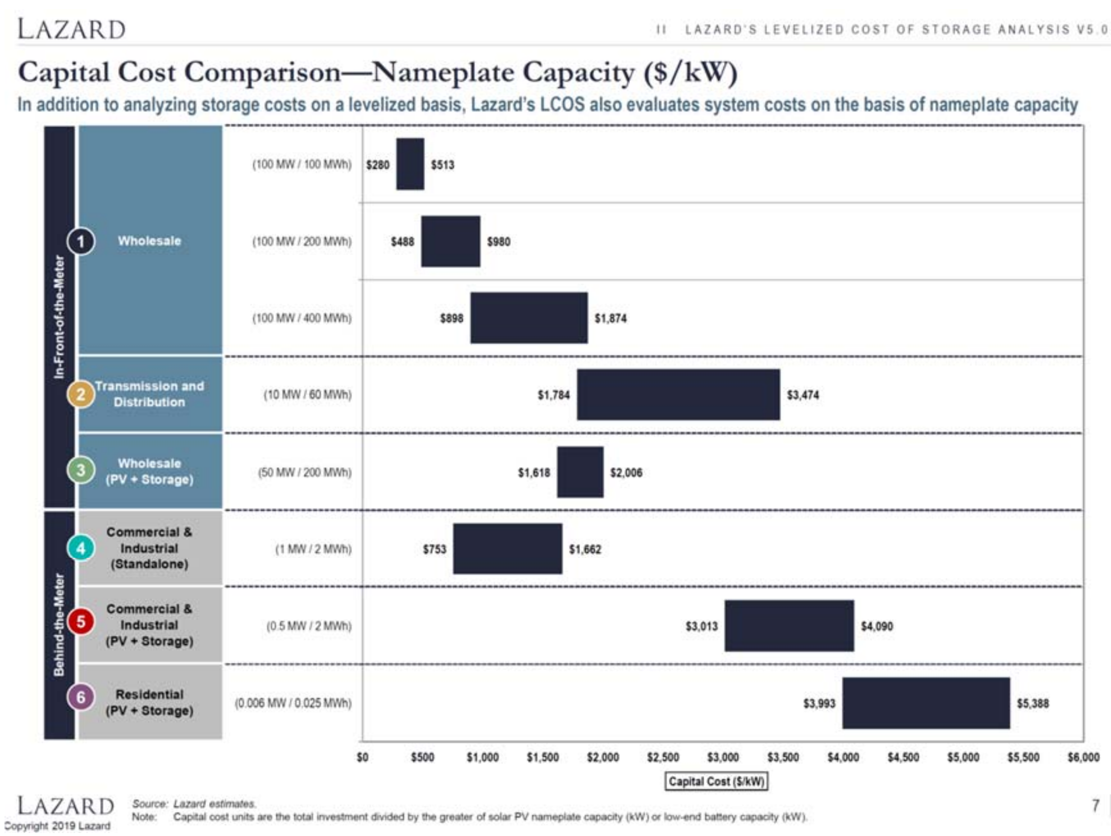
Figure A-1. Vermont 2018 average hourly energy prices



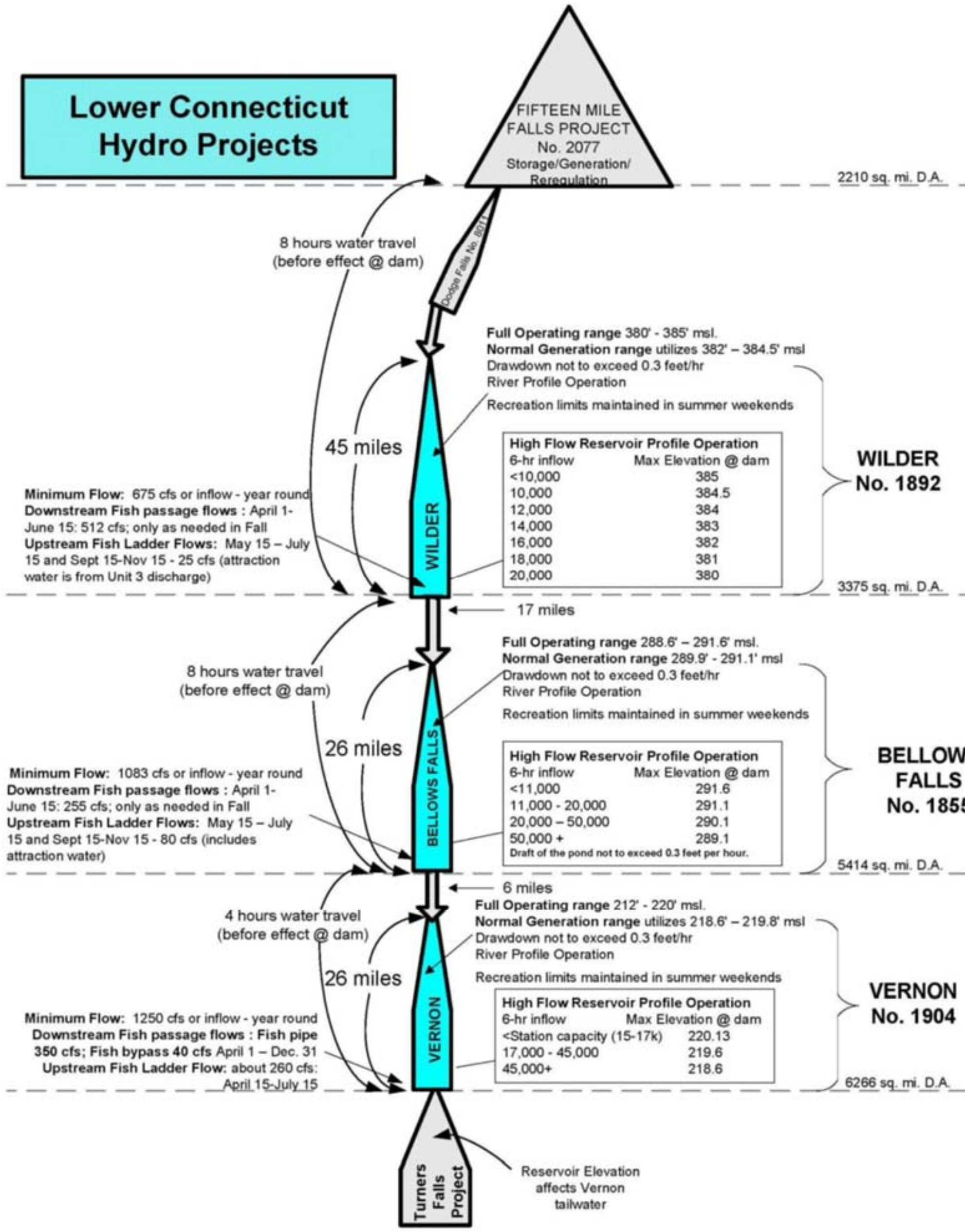
However, this just represents the energy arbitrage in a recent market year. It is expected that, with increased penetration of renewable generation, the daily hourly price range will increase—with prices being very low in some hours of excess generation. In such circumstances the energy arbitrage value of storage resources would be greater.

B. Lazard's Cost of Storage





C. Connecticut River Hydro Operations



Source: Vernon Pre-Application FERC filing, Table 2.5-1 Connecticut River operations summary, page 2--29. Oct 30, 2012.

Battery Storage Feasibility Study for Hydroelectric Plants at Wilder, Bellows Falls, and Vernon

ENGS 174: Energy Conversion Term Project Report

Teja Chatty, Shishi Gachuhi, Evelina Stoikou

Prof. Mark Laser

Table of Contents:

1. Driving questions

This study aims to evaluate the feasibility of integrating a battery storage system (BSS) with the hydropower plants at Wilder, Bellows Falls, and Vernon as an alternative to the current stored hydropower system. The driving questions guiding this study are:

- Should the hydropower plants integrate a battery storage system?
- What type, size and configuration of battery storage must they employ?
- How much would the battery system cost?
- What are the technical and economic barriers?
- What are the policy and tax benefits associated with this transition?

2. Background

2.1. Basics of hydropower

Hydropower plants are located in areas that have large rivers with a natural drop in elevation. In the case of peaking plants, river water is stored in a reservoir behind the dam and is allowed to flow out of the reservoir into the penstock when required to meet peak energy demand. This is in contrast to hydroelectric plants that operate as run-of-river where electricity is generated during the natural flow regimes.

When the dams reach capacity, the gates open and water flows down a penstock. The potential energy in the stored water is therefore converted to kinetic energy. At the bottom of the penstock is a turbine where the high velocity water rotates the rotor of the turbine generating mechanical energy. The turbine turns a shaft in an electric generator converting mechanical energy to electromagnetic energy. Electricity produced is then fed into the grid system for transmission to industrial, homes, offices etc.

Peaking Hydropower Plants

Energy demand varies greatly throughout the day and seasons. The conventional power sources such as fossil fuel plants and nuclear plants are not efficient for meeting short spikes in electricity demands during peak hours. This is because they require long startup times. Peaking hydropower plants, on the other hand, have the ability to generate electricity almost instantly to meet peak energy demands. They collect water behind the damn throughout the day and when energy demand is high, water is allowed to flow through the penstock to the turbine-generator, thereby generating electricity to meet peak demands. For this reason, hydropower plants are mostly operated as peaking plants.

One of the main challenges with peaking hydropower plants is that the daily pool elevation changes of the river put an enormous strain on the river, land, and ecosystem [1]. Riverine species are not adapted to the constant disturbances of the river or to the sudden flow and high velocity flow that is associated with hydro. The constant elevation and drop of the river may result in reduced abundance, diversity and productivity of riverine species over a long period of time. Studies have shown a reduction of biomass of between 40 - 60% in disturbed areas compared to undisturbed areas [1]. In addition, elevation and dropping of the river level may lead to a change in the morphology of the river which can result in further damage to the ecosystem.

2.2. Battery storage for hydropower plants

Peak electricity demands can only be met by energy sources that can inject into the grid instantly. This can only be achieved by the use of storage systems such as peaking hydro power or battery storage. Although peaking hydropower is the most popular form of energy storage, accounting for 95% of utility-scale energy storage, its impacts to the ecosystem cannot be ignored. Alternative forms of storage, such as battery storage have the potential to mitigate the long term effects of daily pool level elevations that are required with peaking hydropower plants. [2]

This can be made possible by coupling a run-of-river hydropower plants with a battery storage system. The combined system can provide both base load and peak load services. The run-of-river system would generate electricity that would feed directly into the grid providing base load services without causing damage to the ecosystem. When the energy demand is low, the electricity generated from the run-of-river plant would be used to charge the battery system instead of feeding directly into the grid system. When electricity demand peaks, the battery system would respond instantly and discharge into the grid thereby meeting peak energy demands.

2.3. Examples of deployment of BSS for hydroelectric power plants

Cordova, a small town located 150 miles southeast of Anchorage, Alaska, is pioneering the integration of a lithium-ion energy storage system (ESS) into a hydropower microgrid. The microgrid run by Cordova Energy Cooperative Inc. (CEC) covers the base load demand with a 6 MW run-of-river, and a 1.25 MW run-of-river hydro generators. CEC's hydropower costs around \$0.06/kWh, while diesel generation can cost as high as \$0.60/kWh. CEC meets about 78% of its annual demand with hydropower alone. A grid-scale ESS enables CEC to reduce its reliance on imported diesel and makes its energy system more holistic and resilient. [3]

This case might be different from that of the Connecticut River Conservancy (CRC), because CEC tries to incorporate battery storage as an energy storage system for the run-of-river hydropower plants. The CRC on the other hand is comparing the feasibility of peaking hydro storage with battery storage.

3. Connecticut River Conservancy

The Connecticut River Conservancy (CRC) is an agency that advocates for the Connecticut River watershed while collaborating with partners across Connecticut, Massachusetts, New Hampshire, and Vermont. One of CRC's main roles is to advocate in the Federal Energy Regulatory Commission (FERC) process that regulates hydropower facilities in the Connecticut River basin.

The five major hydro plants on the Connecticut River account for more than 30% of hydropower generation in New England. The way that most hydro plants work is through 30-50 year licenses that determine minimum flow requirements, impoundment levels, fish passages and operating regimes. Therefore, advocating for the rivers during the re-licensing period is really important to find the best balance between power, environmental, and recreational needs. [4]

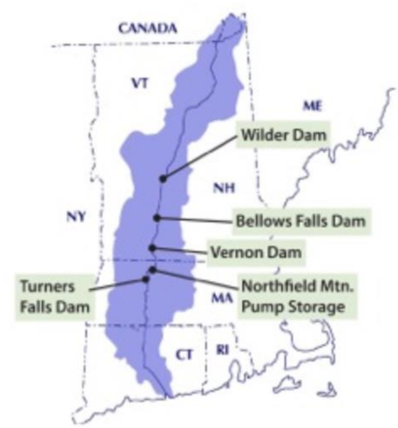


Figure 1: The five major hydro plants in the Connecticut River basin

CRC is concerned with the effects of the peaking hydro plants on the river, land, and ecosystem and this study will examine the feasibility of using battery storage systems in the three main hydro plants in Vermont: Wilder, Bellows Falls, and Vernon. The hydro plants are owned by Great River Hydro, formerly known as TransCanada, and have a total installed capacity of 108.8 kW. Information about their power generation is included in Table 1. [5]

Table 1: Information for hydro plants in study

	Wilder	Bellows Falls	Vernon
Installed capacity	35,600 kW	40,800 kW	32,400 kW
Power generating units	2x 16,200 kW 1x 3,200 kW	3x 13,600 kW	4x 2,000 kW 4x 4,000 kW 2x 4,200 kW

4. ISO energy markets

Wholesale Energy Markets are energy markets where electricity is bought and resold before reaching the end customer. This is carried out by utilities, Independent Power Producers (IPP) and electricity marketers. Wholesale electricity markets are based on competition, supply and demand. In the power grid, supply must meet demand exactly and this balance is regulated by Independent System Operators (ISO) and Regional Transmission Organizations (RTO) through organized markets. The ISO also regulates competition by electricity generators. The ISO manages the energy markets, forward capacity markets, and ancillary markets. [6]

The hydroelectric plants bid into the day ahead market, forward capacity market, reserve markets and. The revenue from the day-ahead and forward capacity markets are their primary sources of revenue. The day ahead market consists of on-peak and off-peak prices. The ISO dispatches the power source that has the lowest cost first and increases supply by dispatching resources of higher prices until demand is met . All power producers that are called upon are paid a uniform price referred to as the clearing price. This price is set by the last power producer that met electricity demand. Forward capacity markets (FCM) exist to ensure that the grid can meet future demand. Power producers bid into the FCM three years in advance to the commitment period and are paid based on the capacity they bid basis regardless of whether they are called upon or not. These markets are integral to understanding the financial impact of converting a peaking hydroelectric plant to a run-of-river plant.

5. Battery system options

5.1 Battery basics

A battery contains one or more electrochemical cells, connected in series or parallel to achieve a desired voltage and power. The anode is the electronegative electrode from which electrons are generated to do external work. The cathode is the electropositive electrode to which positive ions migrate inside the cell and electrons migrate through the external electrical circuit. The electrolyte allows the flow of ions, for example, lithium ions in Li-ion batteries allow flow from one electrode to another. The electrolyte is commonly a liquid solution containing a salt dissolved in a solvent. The electrolyte must be stable in the presence of both electrodes.

Electricity in an AC system cannot be stored as such, and needs to be converted to electrochemical, electromagnetic, potential or kinetic energy. Any energy storage technology is characterized by the amount of energy that can be stored in the device, and the rate at which energy can be transferred into or out of the system.

5.2 Battery selection

Key factors to consider when selecting the battery type for a given scenario include but are not limited to: power rating, energy rating, lifetime, power density, energy density, response time, round trip efficiency, capital and operating costs, and technological maturity. The following table compares various energy storage systems and lists their applications and advantages/disadvantages:

Table 2: Comparison of energy storage technologies [7], [8]

Energy Storage Technologies	Power rating (MW)	Capacity (MWh)	Lifetime (years)	Cycle Efficiency (%)	Advantages	Disadvantages	Power Applications	Energy Applications
Lead-acid batteries	-	-	5-15	75-90	Low power density, low capital cost	Limited lifetime when deeply discharged	Fully suitable and capable	Feasible but not economical or practical
Lithium-ion batteries	0.001-0.1	-	5-15	80-95	High power & energy densities, high efficiency	High production cost, requires a special charging circuit	Fully suitable and capable	**Feasible but expensive**
Sodium-sulfur batteries	0.05	0.4	10-15	80-85	High power energy	**Safety concerns**	Fully suitable and capable	Fully suitable and capable

					density, efficiency			
Flow batteries	0.05-15	120	10-20	75-85	**Independent power & energy ratings**	Low capacity	Suitable	Fully suitable and capable
Pumped hydro	<3000	Depends on size	**40-60**	65-85	High capacity	Special site requirement	Not feasible or economical	Fully suitable and capable

We note from the table that: pumped hydro storage has the longest lifetime compared to any of the electrochemical battery options. Li-ion batteries currently achieve the highest efficiencies, while flow batteries offer the flexibility to vary the power and energy ratings independently. Although Sodium Sulfur batteries currently make up the highest percentage of electrochemical batteries deployed at utility scale, it brings with it safety concerns that still need work. [8]

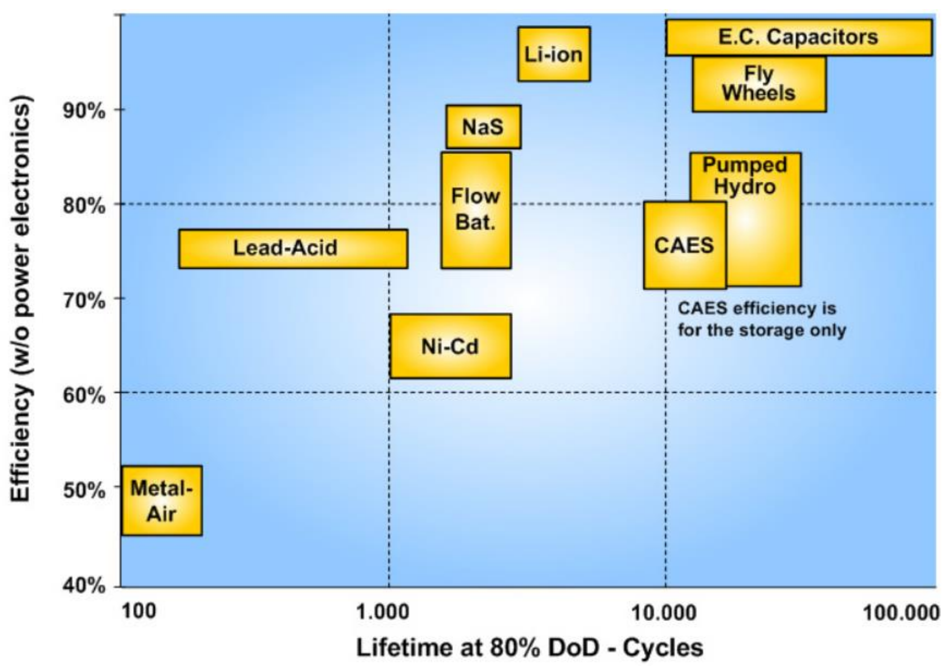


Figure 2: Graph comparing energy storage systems on their efficiency and lifetime [9]

Based on trends in recent deployment, declining prices, high efficiency and decent lifetime, we decided to select **Li-ion batteries** for our further analysis. [10] The image below showcases the battery components of utility scale storage system [11], [12].

Figure 3: Battery system components [13]

6. Methodology

For this study, we analyzed generation data from the hydropower plants, made assumptions applicable to the context, and used results from the flexibility study conducted by UMass to guide our scenarios for integration of battery storage. The following subsections detail our approach and analyses.

6.1. Generation data analysis

Monthly generation data for the years 2000-2011 of the three hydro plants was provided to us by CRC. The average of generation from this data was used as an estimate for future generation output for each hydro plant, as shown in Figures 4-6.

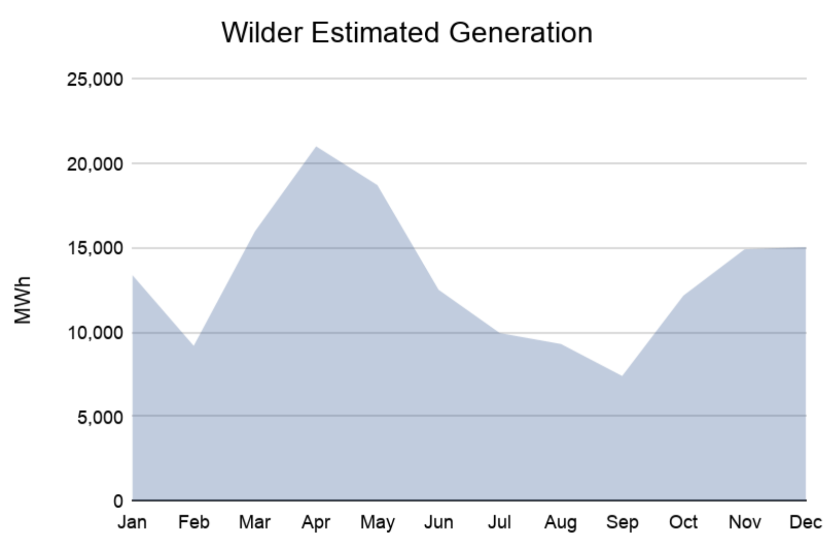


Figure 4: Monthly average generation for Wilder Dam (2000-2011)

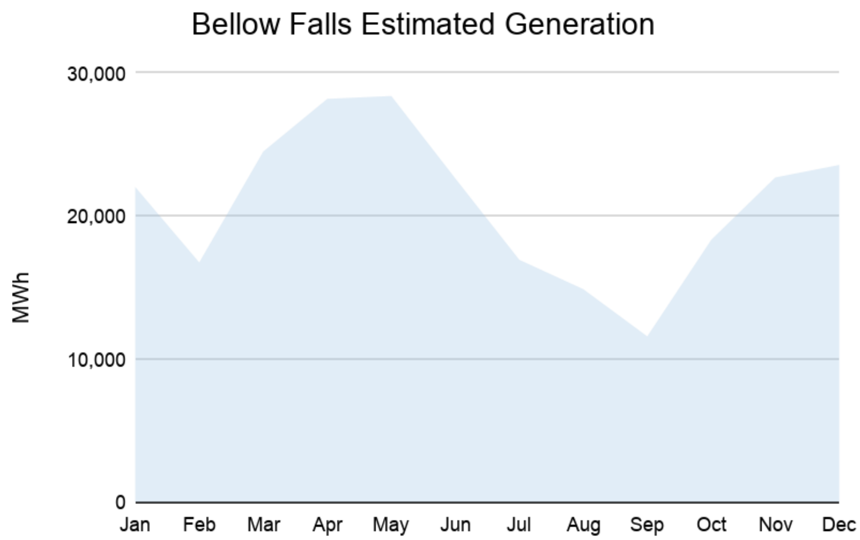


Figure 5 : Monthly average generation for Bellow Falls Dam (2000-2011)

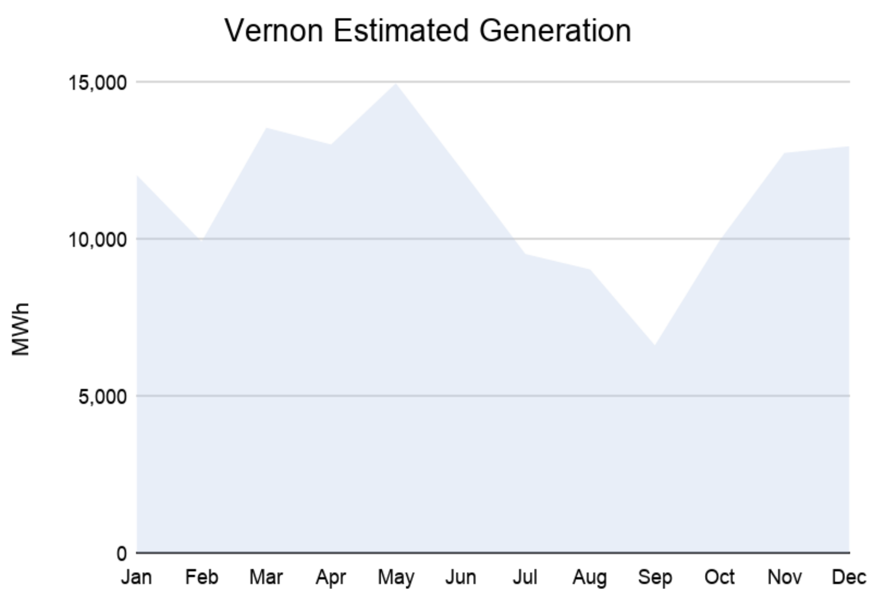


Figure 6: Monthly average generation for Vernon Dam (2000-2011)

The standard deviation for generation output of the plants for across the years was found to be relatively low, confirming that the average would be an appropriate estimate for future power generation. Figure 7 shows that the generation trends remain similar across years.

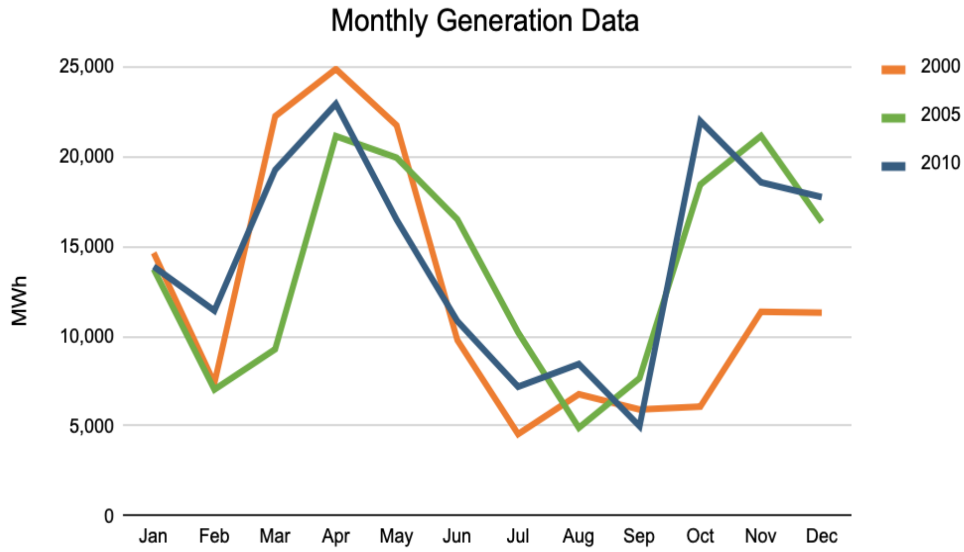


Figure 7: Generation trends for the years 2000, 2005 and 2010

6.2. Revenue and pricing considerations

For our estimation of revenue for various scenarios studied, we used public information on loads, pricing and market information provided by Great River Hydro and ISO New England.

We started with the Federal Energy Regulatory Commission (FERC) revenue reportings for the three hydro-plants. Figure 8 showcases the revenue generated from on-peak and off-peak energy, forward capacity markets, real-time reserves, volt-ampere-reactive support, and renewable credits.

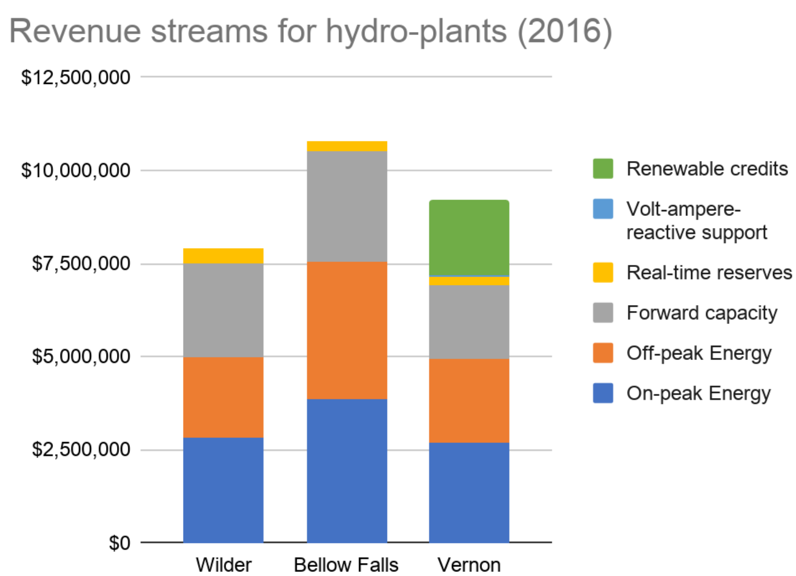


Figure 8: Revenue streams for the three hydropower plants

Energy prices for each dam (in $/MWh) shown in Table 3 were calculated by dividing the total revenue by the total generation. We found this value to be within margin of error of the average price documented in publicly available data. The capacity and ancillary revenue were calculated by dividing the corresponding revenues by the total capacity (MW) and generation (MWh) respectively. The % on-peak energy and % off-peak energy were determined to be proportional to the revenues associated with on and off peak energies documented.

Table 3: Energy and revenue calculations

	Wilder	**Bellow Falls**	**Vernon**
Energy Price ($/MWh)	30.67	30.5	29.95
Reference Year Average Price	29.62	29.62	29.62
Capacity Revenue ($/MW)	51,313	67,936	34,546
Ancillary Revenue ($/MWh)	2.47	1.14	1.66
% on-peak energy	**57%**	**51%**	**54%**
% off-peak energy	**43%**	**49%**	**46%**

We then used the monthly generation data to estimate the average generation per day, under the assumption that the plants operate every single day of the month. The percentage on-peak and off-peak energy estimated from revenue was used to calculate the average share of on-peak and off-peak generation per day. The following graph summarizes the maximum and minimum on-peak and off-peak generation on average per day.

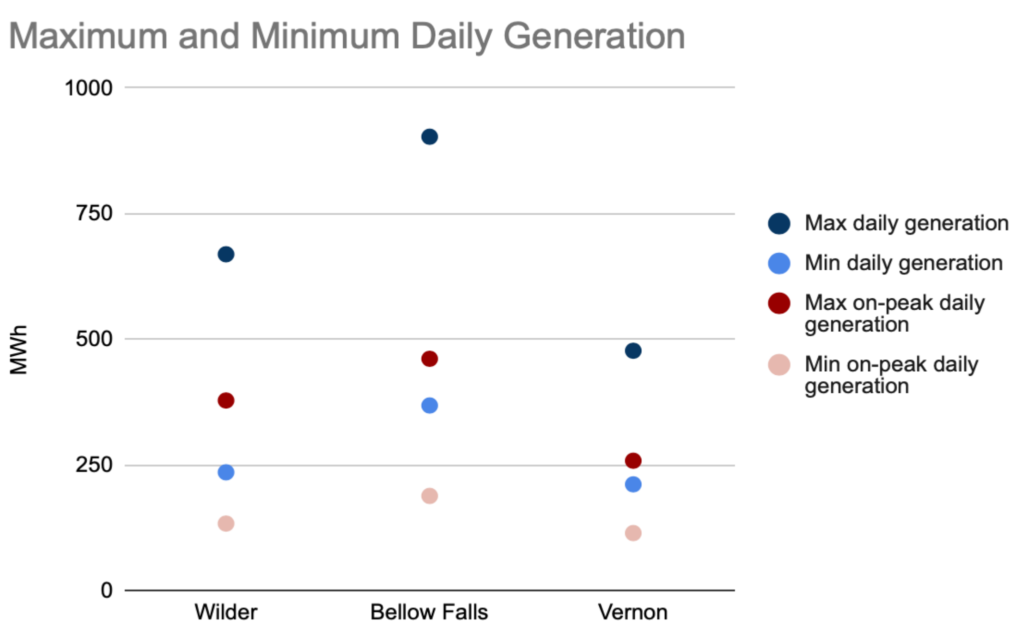


Figure 9: Maximum and minimum daily generation averages for each dam

6.3. UMass flexibility study scenario

The scenario considered in this study is based on a flexibility study conducted by a research group at the University of Massachusetts Amherst. Their research was titled “Investigating the Integration of Flexibility into Dam Operation Planning”. In their analysis, they considered change in revenue when the river’s inflow equals outflow (IEO) versus when there is a percentage deviation from the IEO condition. The IEO constraint equates the inflow to the outflow on any given day.

We work with the revenues corresponding to the seasonal minimum flows obtained from this analysis, as an estimate of the percentage losses of revenue and flow encountered when the dam transitions to operate as run-of-river. The table below shows the percent loss in revenue across nine years for each dam.

Table 4: Revenue and percentage losses associated with seasonal minimum flows

Dam	9 Year Revenue Baseline ($)	Seasonal Min Flows ($)	Percent loss
Wilder	92,496,909	90,210,371	-2.47%
Bellows Falls	136,793,775	134,278,255	-1.84%
Vernon	82,509,892	80,939,211	-1.90%
TOTAL	311,800,576	305,427,838	-2.04%

6.4. Integration of the Battery Storage System

The assumptions and calculations of revenue and percent losses associated with transitioning to run-of-river in comparison with the business-as-usual, led us to identifying and sizing a battery storage system (BSS) best suitable for the scenario. The BSS would charge when energy prices are low and generate when the prices are high, making a revenue from arbitrage. This would supplement the revenue made from letting the dam generate electricity by run-of river thereby making up for losses associated with the transition from stored hydro.

The following subsections discuss the assumptions made and calculations performed to identify the right size and configuration of the battery storage system to meet the revenue requirements.

6.4.1 Battery Operations

Our battery system will be charged between 12:00 am and 5:00 am where energy demand and prices are low. Each battery requires 5 hours to charge to full capacity. With a depth of discharge (DoD) of 80%, they can discharge for 4 hours [14]. Batteries will discharge during peak hours between 7:00 am and 10:00 pm.

6.4.2 Revenue calculations

The battery systems will charge during off-peak hours when the day-ahead energy prices are low and will discharge during on-peak hours when electricity prices are high. In 2017, the average on-peak prices were $37.63 /MWh while the average off-peak prices were $28.95/MWh in Vermont. These average prices were necessary to determine the revenue lost from operating as a run-of-river hydropower plant as opposed to a peaking hydroelectric plant. The following figure displays the variation in on-peak and off-peak prices throughout the year for 2017. [15]

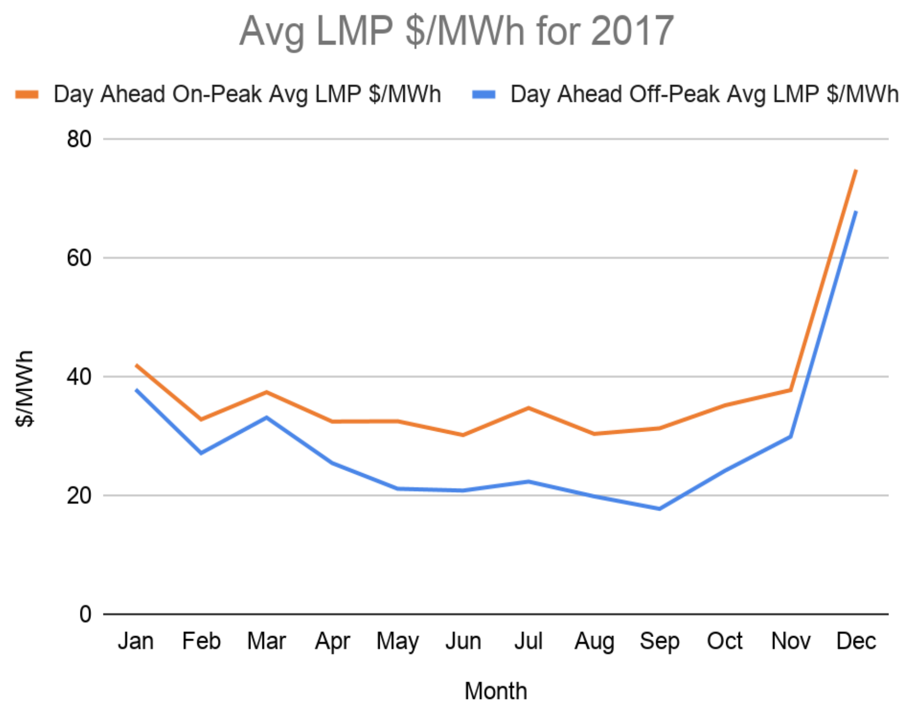


Figure 10: Day-ahead on-peak and off-peak pricing per month [6]

Using the average on-peak and off-peak energy prices in 2017, we determined the revenue streams from load shifting are as follows:

- Revenue lost from charging the battery system for 5 hours between 12:00 - 5:00 am totals to **$144.75/MWh**
- Discharging the battery during 4 peak hours during the day would result in a revenue of **$150.52/MWh**
- This results in a net increase in revenue of **$5.77/MWh**. We make a simplifying assumption that this net increase in revenue is uniform throughout the year.

The battery size will be determined in accordance with the net revenue in order to meet the revenue lost when transitioning to run-of-river. Table 5 below shows the generation (MWh) losses in a year and the resulting revenue losses per day. The battery capacities required to recover these losses through load shifting are shown in the table below. [16]

Table 5: Battery sizing

Dam	Generation (MWh)	Energy Revenue	Percent loss	Generation lost	Revenue Lost/Day	MWh battery to recover lost revenue
Wilder	163,145 MWh	$5,004,205	-2.47%	-4,029 MWh	$388.64	**58.69 MWh**
Bellows Falls	247,388 MWh	$7,544,867	-1.84%	-4,551 MWh	$380.34	**65.92 MWh**
Vernon	165,104 MWh	$4,944,984	-1.90%	-3,136 MWh	$257.41	**44.61 MWh**

6.4.3 Battery Sizing

By selecting a duration of 4h for the battery system and in order to meet the capacity required to recover the lost revenue, the battery systems for the hydropower plants would need to have the following specifications.

Table 6: Estimated battery specifications to meet revenue requirements

Dam	Power	Capacity	Duration	Revenue from FCM Battery
Wilder	15 MW	60 MWh	4h	$840,351.33
Bellows Falls	16.25 MW	65 MWh	4h	$943,839.74
Vernon	11.25 MW	45 MWh	4h	$638,774.16

How does changing from peaking to RoR change the amount of capacity that the plant can bid into the Forward Capacity Markets? Incorporating a battery storage system has the potential to increase the overall capacity of the hydropower plant. If a 60 MWh battery system with a 4-hour duration is incorporated, this will result in an increased capacity of 15 MW. The hydropower plant can bid this additional capacity into the forward capacity market resulting in increased revenue as shown in Table X above based on the average FCM price of $57,274/MW. [16]

6.4. Battery size, manufacturers and configuration

The table below lists existing battery storage system options in the market by prominent companies for utility scale applications. The exact costs were not always available as the manufacturers only respond to business quotes. Therefore, we employed the capital costs estimated by Lazard for our financial analysis detailed in the subsequent section.

Table 7: Table with major lithium-ion manufacturers and battery specifications [17], [18], [19], [20],

Manufacturers		**Unit options**	**Power rating**	**Capacity rating**
	BYD	1	250 kW	1 MWh
		2	500 kW	1 MWh
		3	1 MW	1 MWh
		4	1.8 MW	800 kWh
	Fluence	Advancion	2-100+ MW	
	GE	Energy RSU-4000	1.2 MW	4.18 MWh
		Mid-Power	0.96 MW	3.7 MWh
		High Power	0.72 MW	2.5 MWh
	SAFT Intensium	Max + 20M	2.5 MW	1.09 MWh
		Max + 20P	2.8 MW	0.7 MWh
	Samsung SDI	E3-M090	-	122 kWh
	TESLA	Powerpack	50 kW	210 kWh
		Megapack	-	3 MWh

7. Financial Analysis

Battery systems are purchased in units with preset energy, and power ratings. Our calculations are therefore based on battery specifications of Energy RSU-4000 battery system from General Electric. This is a 4.18 MWh battery storage system, with a maximum power of 1.2 MW.

The number of units, energy, and power outputs from these battery systems is shown in Table 8 below. GE does not disclose the costs of these units, therefore, we used the capital cost projections for lithium-ion battery technology provided by Lazard, as seen in Figure 11 below. This cost for 2019 is approximately $500/kWh.

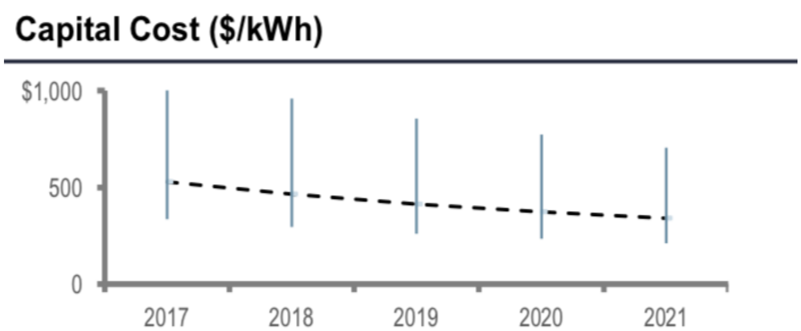


Figure 11: Levelized cost of battery storage options [21]

Table 8: Estimated capital cost of deploying the battery storage system

Dam	# of RSU-4000 batteries	Capacity	Cost ($500/kWh)
Wilder	14	58.52 MWh	**$29.26 M**
Bellows Falls	16	66.88 MWh	**$33.44 M**
Vernon	11	45.98 MWh	**$22.99 M**

8. Tax incentives and policy

8.1. Energy storage tax incentive and deployment act

A new legislation introduced in the House of Representatives by Congressman Mike Doyle, seeks to modify the federal tax code to include energy storage as an eligible technology for Investment Tax Credit (ITC). Currently the ITC under Section 48 and 25D of the Internal Revenue Code allows project owners to receive federal tax credits for designated renewable energy generation equipment. This code has covered Solar PV projects since its inception in 2006. In March 2018, the IRS clarified that battery storage may also receive credits if it receives a majority of its energy from solar panels. Standalone storage has not been eligible for ITC [22].

This bill has been taken forward when Senators Dianne Feinstein, Martin Heinrich, and Cory Gardner introduced the bi-partisan Energy Storage Tax Incentive and Deployment Act of 2019 in the Senate. A past bill introduced by Sen. Heinrich in 2016 for standalone energy storage never passed the committee.

Highlights of the energy storage tax incentive and deployment act:

- Business energy investment credit for energy storage: For commercial applications, the bill provides the same tax incentive as currently available for solar energy in section 48 of the IRS code. All energy storage technologies would qualify, including batteries, flywheels, pumped hydro, thermal energy, compressed air, etc. To qualify for the ITC, the system must have a storage capacity of at least 5 kilowatt-hours. The credit allowed is the same as currently available for solar energy, including the phase down. The IRS currently allows a limited ITC for energy storage when it is installed in conjunction with a solar or wind energy system. The bill would extend the ITC for any energy storage project in all applications, including consumer-owned, grid-connected, or off-grid.
- Residential energy property tax credit for energy storage: For residential applications, the bill provides homeowners the same credit as currently available for solar energy in section 25D. However, only battery storage is eligible for the residential ITC, and the system must have a storage capacity of at least 3 kilowatt-hours.

8.2. Structure of existing federal tax incentives for energy storage

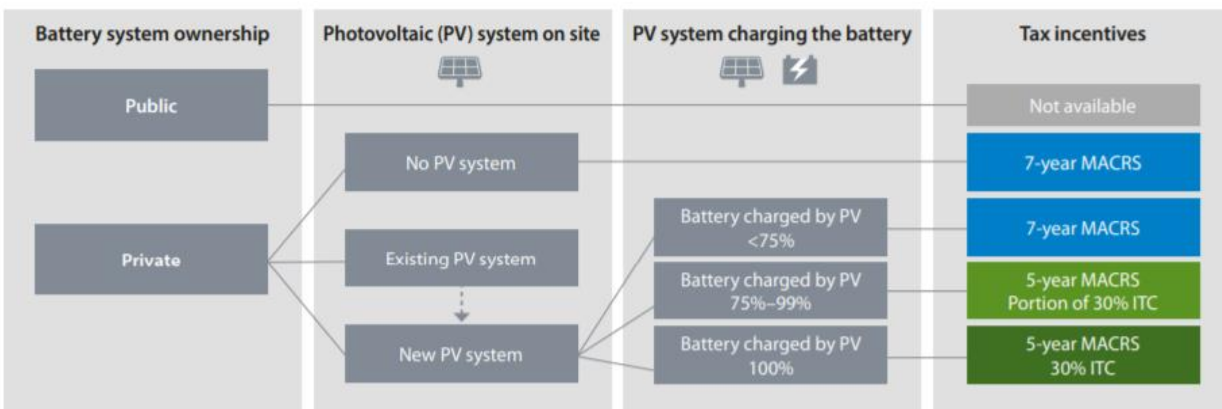


Figure 12: Incentives for battery systems

In the current system, Investment Tax Credit (ITC) and the Modified Accelerated Cost Recovery System (MACRS) depreciation deduction may apply to energy storage systems such as batteries depending on who owns the battery and how it is used. If the battery is owned by a public entity such as a public university or federal agency, they are not eligible for tax-based incentives. If owned by a private party, battery systems may be eligible for some benefits [23].

Modified Accelerated Cost Recovery System:

- Without a renewable energy system installed, battery systems may be eligible for a 7-year MACRS depreciation schedule: an equivalent reduction in capital cost of about 20%.
- If the battery system is charged by a renewable energy system by more than 75% of the time on an annual basis, the battery should qualify for the 5-year MACRS schedule, equal to about 21% reduction in capital costs.

Investment Tax Credits:

- Battery storage systems charged by a renewable energy system for more than 75% of the time are also eligible for Investment Tax Credits (ITC). This is currently 30% for systems charged by PV which will be declining to 10% from 2022 onwards.
- Battery systems charged by a renewable energy system for 75-99.9% of the time are eligible for that portion of the value of the ITC.
- For example, a system charged by renewable energy 80% of the time is eligible for the 30% ITC multiplied by 80%, which equals a 24% ITC instead of 30% (the tax credit is vested over 5 years, and recapture can apply in unvested years if the percentage of renewable energy charging declines).
- Battery systems that are charged by a renewable energy system 100% of the time on an annual basis can claim the full value of the ITC [23], [22].

9. Ownership options for the battery system

Except from tax incentives and policy, the hydropower plants can avoid the high capital costs of the battery system by having a different company own and operate the battery system. The third-party company would incur the initial high capital costs of the batteries and would operate the system. At the same time the hydro plants would have an agreement with that company and receive compensation for having the battery in their property.

One example where a battery system is owned and operated by a third-party is that of Arsenal's Emirates Stadium in London. Pivot Power was the company that installed the system and it will operate it for the next 15 years. Their 3MW battery will generate income by providing services to National Grid to help it balance supply and demand, which will be shared between Pivot Power, Downing LLP and Arsenal. [24]

10. Scope for future work

Further investigation ought to be carried out to accurately determine the financial impact of converting the peaking plants to run-of-river hydropower plants. We suggest:

- Evaluating the impact of run-of-river operations on the capacity that the hydropower plants can bid into the **forward capacity markets**. This will accurately determine the overall change in revenue from operating as run-of-river plant.
- Varying the **battery size** to lower the net present cost of the battery system. A larger battery system will result in increased on-peak and capacity revenue streams, however, the battery system will have higher initial capital costs.The battery system size can be optimized for the lowest net present costs.
- Performing a detailed **financial analysis** that will include the return on investment (ROI) and payback time for the battery system.
- Identifying the **optimal time** to install the battery system taking into account tax incentives that might become available in the future as well as declining cost of batteries.

11. References

[1] O. Moog, “Quantification of daily peak hydropower effects on aquatic fauna and management to minimize environmental impacts,” *Regulated Rivers: Research & Management*, vol. 8, no. 1–2, pp. 5–14, 1993.
[2] S.-H. Chen, “Circulating hydroelectricity generating and energy storing apparatus,” US20090160192A1, 25-Jun-2009.
[3] “Cordova’s Microgrid Integrates Battery Storage with Hydropower | Transmission & Distribution World.” [Online]. Available: https://www.tdworld.com/energy-storage/cordova-s-microgrid-integrates-battery-storage-hydropower. [Accessed: 18-Nov-2019].
[4] “Cleaner and Greener Hydropower – Connecticut River Conservancy.” .
[5] “Great River Hydro, LLC Relicensing » Wilder Project FERC No. 1892.” .
[6] “ISO New England - Energy, Load, and Demand Reports.” [Online]. Available: https://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/whlsecost-hourly-newhampshire. [Accessed: 27-Nov-2019].
[7] I. Hadjipaschalis, A. Poullikkas, and V. Efthimiou, “Overview of current and future energy storage technologies for electric power applications,” *Renewable and Sustainable Energy Reviews*, vol. 13, no. 6, pp. 1513–1522, Aug. 2009.
[8] M. Aneke and M. Wang, “Energy storage technologies and real life applications – A state of the art review,” *Applied Energy*, vol. 179, pp. 350–377, Oct. 2016.
[9] “Energy Storage Technologies for Electric Applications.” [Online]. Available: http://www.sc.ehu.es/sbweb/energias-renovables/temas/almacenamiento/almacenamiento.html#Comparative. [Accessed: 27-Nov-2019].
[10] F. S. Barnes and J. G. Levine, *Large Energy Storage Systems Handbook*. CRC Press, 2011.
[11] G. J. May, A. Davidson, and B. Monahov, “Lead batteries for utility energy storage: A review,” *Journal of Energy Storage*, vol. 15, pp. 145–157, Feb. 2018.
[12] H. C. Hesse, M. Schimpe, D. Kucevic, and A. Jossen, “Lithium-Ion Battery Storage for the Grid—A Review of Stationary Battery Storage System Design Tailored for Applications in Modern Power Grids,” *Energies*, vol. 10, no. 12, p. 2107, Dec. 2017.
[13] “Batteries 101 Series: How to Talk About Batteries and Power-To-Energy Ratios | State, Local, and Tribal Governments | NREL.” [Online]. Available: https://www.nrel.gov/state-local-tribal/blog/posts/batteries-101-series-how-to-talk-about-batteries-and-power-to-energy-ratios.html. [Accessed: 27-Nov-2019].
[14] T. Vandervort, “Strawman: NAESB ‘On-Peak’ and ‘Off-Peak’ Periods,” p. 2.
[15] “Forward Capacity Market.” [Online]. Available: https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/. [Accessed: 27-Nov-2019].
[16] “How Resources Are Selected and Prices Are Set in the Wholesale Energy Markets.” [Online]. Available: https://www.iso-ne.com/about/what-we-do/in-depth/how-resources-are-selected-and-prices-are-set. [Accessed: 27-Nov-2019].
[17] “ENERGY,” *BYD USA*. .
[18] “Energy Storage Global Leader | Fluence - A Siemens and AES Company,” *Fluence*. [Online]. Available: https://fluenceenergy.com/. [Accessed: 27-Nov-2019].
[19] “Industrial Grid Energy & Battery Energy Storage Solutions | GE Power.” [Online]. Available: https://www.ge.com/renewableenergy/hybrid/battery-energy-storage. [Accessed: 27-Nov-2019].
[20] “Introducing Megapack: Utility-Scale Energy Storage,” 29-Jul-2019. [Online]. Available: https://www.tesla.com/blog/introducing-megapack-utility-scale-energy-storage. [Accessed: 27-Nov-2019].
[21] M. Wilson, “Lazard’s Levelized Cost of Storage Analysis—Version 3.0,” p. 49, 2017.
[22] M. F. Doyle, “All Info - H.R.2096 - 116th Congress (2019-2020): Energy Storage Tax Incentive and Deployment Act of 2019,” 04-Apr-2019. [Online]. Available: https://www.congress.gov/bill/116th-congress/house-bill/2096/all-info. [Accessed: 27-Nov-2019].
[23] E. Elgqvist, K. Anderson, and E. Settle, “Federal Tax Incentives for Energy Storage Systems,” p. 1.
[24] “3MW battery to power Emirates Stadium.” [Online]. Available: https://www.arsenal.com/news/3mw-battery-power-emirates-stadium. [Accessed: 27-Nov-2019].

From: Kathy Urffer
To: "John Ragonese"; "Jennifer Griffin"
Cc: Jeff Crocker (jeff.crocker@vermont.gov); Eric Davis (Eric.Davis@vermont.gov); "Simard, Betsy"; "Harris, Hannah"; Melissa Grader (Melissa_Grader@fws.gov); Lael Will (Lael.Will@vermont.gov); Matt Carpenter (matthew.carpenter@wildlife.nh.gov); Gregg Comstock (Gregg.Comstock@des.nh.gov); Katie Kennedy (kkennedy@TNC.ORG); afisk@ctriver.org; Andrea Donlon
Subject: Battery information
Date: Monday, March 23, 2020 1:33:00 PM
Attachments: image001.png
Vernon Hydro and Battery Storage Report_2.4.2020.pdf
ENGS 174 Final Report - Teja Shishi Evelina_.pdf

John and Jennifer,
I hope you and your families are all doing well in this bizarre time!
Thank you for sending over the information on markets and for being willing to engage in the coming conversations. I honestly really appreciate your efforts and transparency.

During our meeting last month I said that I would send over the battery study information. Attached are:

1) The final paper done by the three engineering students at Dartmouth
2) Synapse report which focuses on Vernon as a case study.

I hope these are useful to you as you consider options going forward. We also plan to submit these to FERC to be added to the docket.

Take care!

Best,
Kathy

~ ~ ~ ~ ~ ~ ~ ~ ~ ~ ~

Kathy Urffer
River Steward
Connecticut River Conservancy, formerly *Connecticut River Watershed Council*
PO Box 6219 | Brattleboro, VT 05302 | www.ctriver.org
802-258-0413 | kurffer@ctriver.org

Clean water. Healthy habitat. Thriving communities.
Connecticut River Conservancy

CLICK HERE TO BECOME A MEMBER

From: Andrea Donlon
To: Donald.Traester@firstlightpower.com; "Marc Silver"; "Mark Wamser"
Cc: Andy Fisk; Kathy Urffer
Subject: Battery reports - CT River Conservancy
Date: Wednesday, March 25, 2020 4:31:03 PM
Attachments: Vernon Hydro and Battery Storage Report 2.4.2020.pdf
ENGS 174 Final Report - Teja Shishi Evelina .pdf

Dear Don and Marc,

I hope this finds you healthy and well, and thank you for being on one of the front lines of providing essential services while the global community tries to slow the spread of this virus.

Earlier in 2020, CRC commissioned Synapse Energy Economics to look into the economic feasibility of transitioning Vernon Dam to a run-of-river facility paired with battery storage to capture some of the peak energy prices. A team of Dartmouth engineering students also looked at a similar question in late 2019. We recently shared these reports with Great River Hydro and some of the stakeholders in that relicensing effort, and will be submitting these to FERC to add to the docket. As a courtesy, we are sending them to you before they go to FERC.

Attached are:

1) The final paper done by the three engineering students at Dartmouth.
2) Synapse report which focuses on Vernon as a case study.

I hope these are useful to you as you consider options going forward. We only had enough grant money to look at a single facility, and we chose Vernon, but would have been interested in looking more in depth at the four dams on the CT River going through relicensing. We'd be happy to discuss more if desired.

Take care, Andrea

____

ANDREA DONLON
River Steward
Connecticut River Conservancy, formerly *Connecticut River Watershed Council*
15 Bank Row | Greenfield, MA 01301 | www.ctriver.org
413-325-4426 (mobile) | adonlon@ctriver.org
[For the time being, the best way to call me is cell phone # above or home land line: 413-625-8178]
Office number: 413-772-2020 x205
Pronouns: she/her

Clean Water. Healthy Habitat. Thriving Communities.