The Future Role of Hydropower in the Northeastern United States

May 2020–May 2022

Nicholas W. Miller[1] and John M. Simonelli[2]

1 HickoryLedge LLC
2 Flashover LLC

NREL Technical Monitor: Greg Stark

NREL is a national laboratory of the U.S. Department of Energy
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Foreword

This report was commissioned by the U.S. Department of Energy's Water Power Technologies Office and written by hydropower industry experts Nicholas Miller and John Simonelli. It is important to note that the insights and suggestions proposed in this report are solely the opinions of the authors. However, it is equally important to emphasize the deep knowledge and experience they have gained from working with U.S. power systems.

Both authors have over 40 years each of industry experience, specifically in bulk power systems—the network of power plants and transmission lines that create and transmit electricity across regions. They have also dedicated significant portions of their careers to strategizing how to integrate renewable energy into power systems across the world, and their decades of work have earned them prestigious lifetime achievement awards.

Simonelli spent over 40 years in the hydropower industry and served as chairman, vice chairman or member of numerous industry groups, including the North American Electric Reliability Corporation, North American Energy Standards Board, and Northeast Power Coordinating Council, Inc. He retired from ISO New England in 2018 and currently works as an industry expert consultant. Miller is a veteran power systems engineer. He earned several patents for his work as an inventor and technology developer for General Electric. He also helped develop the National Renewable Energy Laboratory's Western Wind and Solar Integration Study. Miller, who has counselled utilities and governments in more than three dozen countries, dedicated his career to finding effective and efficient ways to integrate wind and solar energy into electric power grids. He retired in 2018 and now works as a consultant.

With this report, Miller and Simonelli share their expert opinions on how hydropower can best support the reliable and economic evolution of the New England power system and, more broadly, all U.S. energy grids. It is their intention that the recommendations herein can serve as a guide for the responsible decarbonization of the U.S. energy sector.

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List of Acronyms

AC	alternating current
AGC	automatic generation control
BA	Balancing Authority
CELT	Capacity, Energy, Loads, and Transmission (Report)
DC	direct current
ERS	essential reliability services
FERC	Federal Energy Regulatory Commission
GW	gigawatt
HVAC	high-voltage alternating current
HVDC	high-voltage direct current
ISO	independent system operator
ISO-NE	Independent System Operator New England
NERC	North American Electric Reliability Corporation
NREL	National Renewable Energy Laboratory
PFC	primary frequency control
PSH	pumped storage hydropower
PV	photovoltaics
RoCoF	rate of change of frequency
VSPSH	variable-speed pumped storage hydropower

Executive Summary

This report explores the future role of hydropower in the northeastern United States. The intent is to provide experience-based insights into how hydropower can best support the reliable and economic evolution of the New England power system and, more broadly, all U.S. grids. The potential integration of 10s of Gigawatts (GW) of variable energy resources into the New England system will introduce several reliability and resiliency challenges. Aggressive and creative application of existing and new hydro resources presents opportunities to enhance the reliability, economy and decarbonization on the system.

Today, New England has just under 2 GW of installed conventional hydropower and a similar amount of pumped storage hydropower (PSH), totaling roughly 10% of the region's present capacity. Peak net load, considering behind-the-meter photovoltaics and energy efficiency, will remain at around 25 GW for the next decade. The proposed 15 GW of grid-connected variable renewables to be added in that time, comprising mainly offshore wind energy, land-based wind energy, and solar photovoltaics, represents a radical change in the resource mix. Periods of substantial overgeneration—possibly exceeding 40% of peak load—and potential power ramps on the order of 20 GW over a few hours present major operating challenges. The accompanying displacement of synchronous fossil-fuel generation and loss of their essential reliability services will also be challenging.

Hydropower can assist in remediating several issues; this report explores how it might provide benefits that proportionally exceed its small share of the New England portfolio in a low-carbon future. Hydropower can assist in handling periods of overgeneration, reduce the risk of curtailment of zero-carbon resources, improve market efficiency, and provide valuable essential reliability services.

Opportunities and Recommendations

Hydropower and PSH plants can deliver a broad spectrum of benefits. Recommendations to help mitigate reliability and resiliency concerns include the following:

- Commit and dispatch hydropower with the specific operational objective of reducing the need for Independent System Operator New England (ISO-NE) to uneconomically dispatch the system. ISO-NE can reduce fossil-fuel must-run requirements, meet North American Electric Reliability Corporation frequency response obligation, support voltage and reactive deficiencies, maintain system short-circuit strength to facilitate stable operation with high levels of inverter-based resources, maintain black-start and system restoration capability, meet synchronous inertia reserve requirements, and reduce the need to curtail zero-carbon resources during increasing periods of overgeneration.
- Develop technical and market mechanisms to incent future PSH (specifically, advanced variable-speed PSH), better compensate all types of hydropower that provide essential reliability services, and recognize the benefits of a hybrid development of hydropower (specifically, PSH) with wind and solar energy resources.
- Consider a revised technical approach to planning that explores opportunities for PSH to improve power transfer levels with neighbors and within ISO-NE, and to share PSH's ability to address excess generation and power ramping challenges across Balancing Authority (BA) boundaries.

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1 Introduction

This report explores the future role of hydropower in the northeastern United States. The intent is to provide experience-based insights into how hydropower can best support the challenges facing U.S. grids. The report focuses on the New England region and addresses planning and operating considerations by the Independent System Operator New England (ISO-NE) drawing heavily on the authors' experiences with that system and with broader zero-carbon variable-renewable integration developments across the globe. This discussion is intended to be a practical and reality-based view that addresses both real challenges and opportunities for hydropower to expand its role in the reliable and economic evolution of the New England power system and, more broadly, all U.S. grids. Discussing critical transmission issues goes beyond the scope of this work.

The ISO-NE system is host to many relatively small conventional hydropower projects and two substantial pumped storage hydropower (PSH) projects (Northfield Mt. and Bear Swamp). Conventional hydropower capacity totals just under 2 gigawatts (GW), as does PSH, each being roughly 5% of the present installed capacity. The challenge facing New England is to continue economic and reliable operation of the system with the substantial changes that will accompany the potential integration of tens of gigawatts of variable energy resources. Successful integration of these resources presents opportunities for the future ISO-NE system to be lower carbon, more economic and more resilient. This discussion recognizes that a few gigawatts of hydropower will not be sufficient to address all the expected challenges but focuses on how to appreciate the benefits of existing and potentially new hydropower resources toward a suite of solutions. When one considers the size of the New England region, the varied geography and population density, the existing generation mix, the location on the edge of the massive Eastern Interconnection grid, and historical dependence on hydropower, these all make the region a good candidate for this investigation.

The motivation for this work stems, in part, from the fact that hydropower, while a modest slice of the entire resource portfolio, is somewhat undervalued. Hydropower can assist in remediating several issues highlighted in this report. Even with hydropower representing a relatively small share of the New England portfolio, the potential benefits of using it more effectively are substantial. The report explores how hydropower might be leveraged to provide benefits that proportionally exceed its share in a future low-carbon resource mix.

2 Overview of the New England and Regional Power System

2.1 New England and Regional Hydropower Resources

The 2 GW of domestic, non-pumped storage hydropower is composed of approximately 37% run-of-river power plants and 63% power plants with some daily to weekly pondage capability. Most of these facilities are very mature dating back to the early 1900s. Some have already undergone upgrades and retrofits.

New England also has access to external hydropower resources from multiple Canadian provinces. The region has both 2,000-megawatt (MW) and 225-MW bidirectional, high-voltage direct current (HVDC) interconnections to Hydro-Québec. Those ties were built to facilitate New England access to abundant low-cost hydropower from Quebec, and the expectation is that there will be sufficient hydropower resources in Quebec to maintain energy exports to New England.

Additionally, New England has a 1,000-MW AC tie to the Canadian Maritimes. This tie allows the export of low-cost Canadian nuclear power and hydropower to New England during summer periods when the load in the Maritimes is low and New England load is high. With the increase in hydropower capacity in Labrador/Newfoundland and the addition of renewable resources across the provinces, one can assume there will be ample energy available for continued export to New England. Based on the current market constructs, external resources from the Canadian provinces must compete economically with internal New England resources. It is not prudent to speculate on how competitive these external resources will be going forward as the region shifts to significant amounts of zero-carbon variable resources. The expectation is that hydropower both internal and external to New England will continue to participate in the capacity and energy markets while providing additional value via a wide range of reliability services.

2.2 New England Resource Trends

The 2020 ISO-NE Capacity, Energy, Loads, and Transmission (CELT) Report and Planning Generator Interconnection Queue (dated June 2020), indicate New England is expected to have a small number of resource retirements over the next 10 years (remaining coal, vintage oil burning, and older, less efficient combined-cycle generators). Looking at the potential new resources over the next 10 years, the region is expected to add significant zero-carbon renewable resources. Currently, the interconnection queue contains more than 2,000 MW of battery energy storage, 3,500 MW of grid-connected photovoltaics (PV), 400 MW of grid-connected PV/battery hybrids, 1,000 MW of land-based wind energy, and more than 11,000 MW of offshore wind energy. The hydro fleet will remain relatively static. The total of all potential resources in the interconnection queue is more than 21,000 MW (Table 1). In addition to the utility-scale solar energy shown in Table 1, there is another 3,000 MW or more of behind-the-meter PV proposed.

Table 1. ISO-NE Resource Mix and Forecast. ***Source: ISO New England (2020)***

Resource Type (ratings in MW)	Current Nameplate (per 2020 CELT)[a]	Planning Interconnection Queue (2020–2029)[b]	Planned Retirements	Potential 2029 Resource Mix
Combined Cycle – CC	16,528	2,539	-1,815	17,252
Fuel Cell – FC	32	25	0	57
Gas Turbine – GT	4,219	0	-195	4,024
Hydropower (Daily or Weekly Pondage) – HDP/HW	1,241	99	0	1,340
Hydropower (Run of River) – HW	753	0	-20	733
Internal Combustion – IC	214	0	-114	100
Battery – ES/BAT	21	2,079	0	2,100
Pumped Storage – PS	1,778	0	0	1,778
Photovoltaics – PV	1,457	3,467	0	4,924
Photovoltaics/Battery Hybrid – PVSUN	0	424	0	424
Steam Turbine – ST	10,514	45	-1,127	9,432
Wind (Land-Based) – WT	1,361	1,016	0	2,377
Wind (Offshore) – WT	30	11,381	0	11,411
Total	38,148	21,075	-3,271	55,952

[a]ISO-NE 2020 Capacity, Energy, Loads, and Transmission (CELT) Report, tab 5.1 (ISO New England 2020). CELT is considered the major forward-reporting medium in New England.
[b]Data from the ISO-NE Interconnection Request Tracking Tool as of June 18, 2020
[c]Retirements from ISO New England Status of Non-Price Retirement Requests and Retirement De-List Bid spreadsheet June 18, 2020

From Table 1, one can postulate various scenarios of what inevitably may be retired and built going forward, but almost every combination results in a substantial excess of generating resources installed on the system. It is not the intent of this report to explore all those combinations but to strictly deal with the realities of one possible scenario of excess generating capacity on the future system.

2.3 Load Trends

The ISO-NE load forecast in the 2020 CELT projects a near-zero gross load growth for the region over the next 10 years. Factor in behind-the-meter solar energy and energy efficiency projections, and the forecasted net load over that 10-year period is slightly negative. This summer peak load forecast occurs at 17:00 when the behind-the-meter PV contribution is small because of the decline in sunlight at that hour (Figure 1).

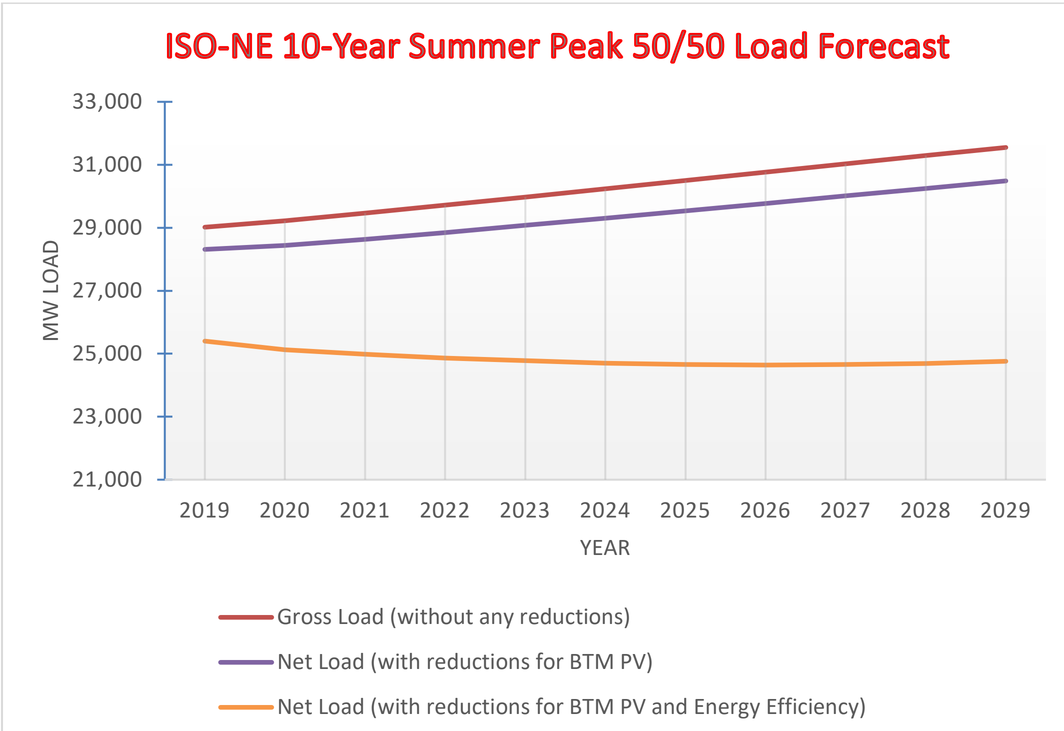

Figure 1. Independent System Operator New England (ISO-NE) summer peak load projections.

Data from the ISO-NE Capacity, Energy, Loads, and Transmission (CELT) Report (tab 1.1, Summer Peak). Load levels represent the megawatts associated with a 50/50 gross peak demand forecast, which is a value within the distribution that peak demand is expected to exceed 50% of the time. It in no way reflects potential extreme weather forecasts. BTM = behind the meter, PV = photovoltaics.

The current absolute minimum system load is slightly more than 8,000 MW and generally occurs in late spring and early autumn. This period may become problematic in the coming decade. Over the last several years, the region has seen a daily load shape that closely resembles the well-documented California Independent System Operator duck curve. The changing load trend is highlighted in the system load duration curve for May 2, 2020, in Figure 2. With significant reductions in daylight minimum load because of PV, there have been increasing incidences over the last 3 years wherein the minimum daytime load has been less than the minimum overnight load. This creates unique operating conditions that deviate from historic conditions. ISO-NE indicates there was one such occurrence in 2018, three in 2019, and thirteen in 2020. Operational challenges are expected to increase over time during light-load periods as more variable zero-carbon resources join the energy mix.

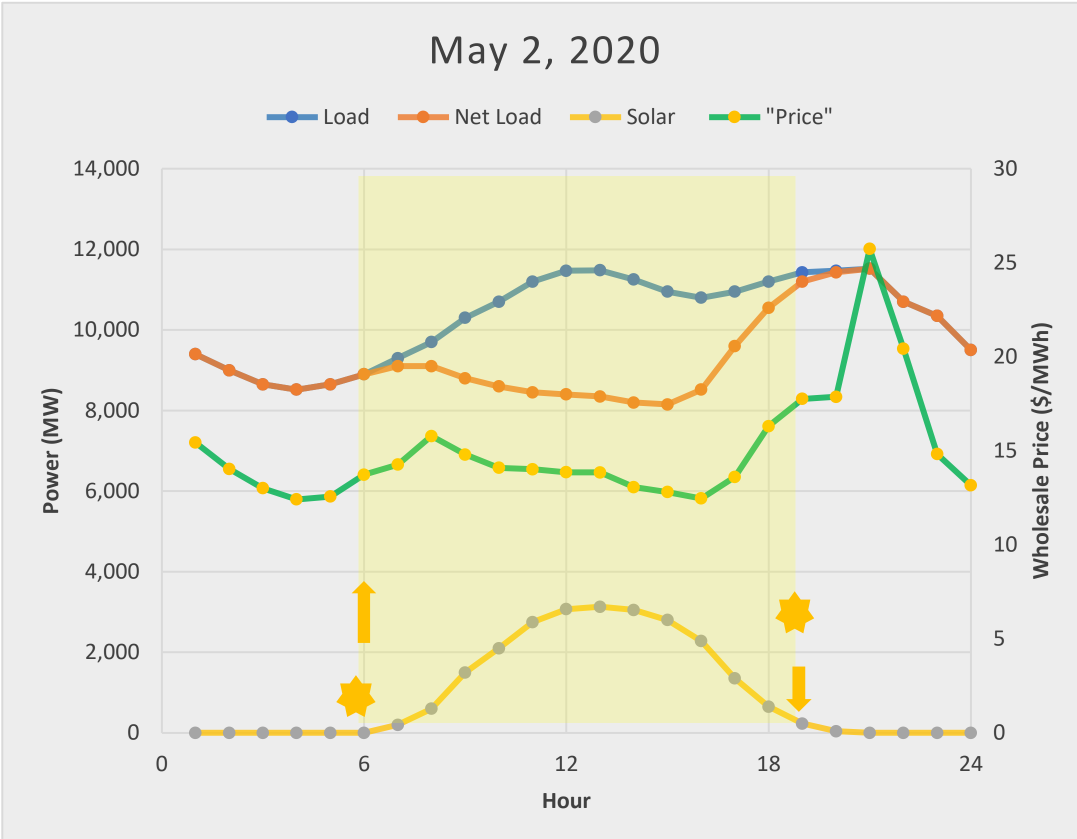

Figure 2. High solar energy day: behind-the-meter PV impact, May 2, 2020. *Data Source: ISO-NE (2021)*

MWh = megawatt-hour.

The wholesale price of electricity is impacted by this change in resource mix. The day-ahead locational marginal price for power in New England for this day is shown in Figure 2 (right-hand scale). Historically, the highest price would have been midday. The substantially higher price during the evening net load peak, shortly after sunset, is a characteristic now being observed in many systems.

2.4 Renewable Targets

The large incremental growth in proposed zero-carbon renewables can be attributed to multistate efforts to reach decarbonization goals in their respective renewable portfolio standards. At this time, a large portion of the solar and wind energy resources in the Generation Interconnection Queue have already entered contractual arrangements with the various New England States. The probability of all proposed resources being constructed is low; however it can be assumed that resources already under contract with various states will have the financial wherewithal to construct the facilities. Figure 3 highlights the steady growth in renewable portfolio standards targets over the next 30 years, as of February 2021, per the U.S. Department of Energy (Barbose 2021). The Maine target of 84% renewable energy by 2030 is the most ambitious.

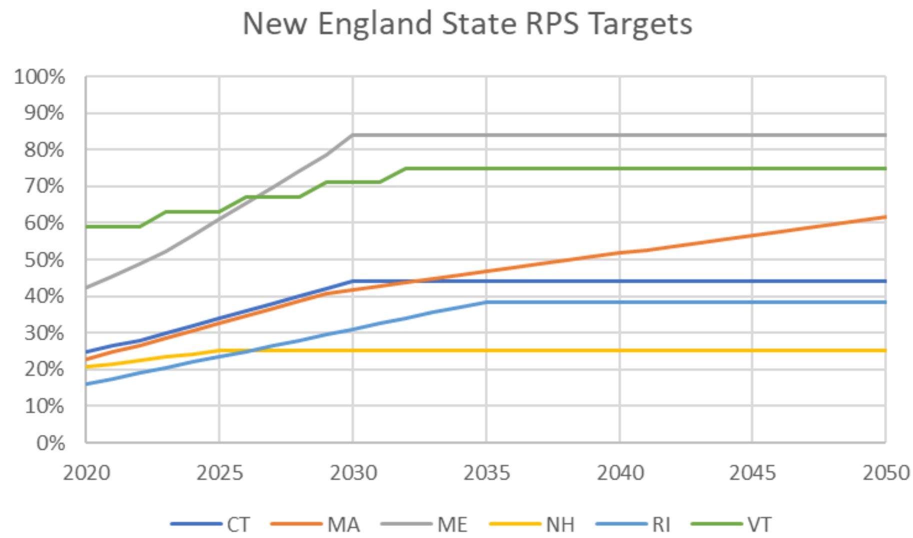

Figure 3. New England renewable portfolio standards (RPS) targets

2.5 Existing New England Transmission

New England is currently interconnected with three neighboring balancing authorities: New York and the provinces of New Brunswick and Quebec, as illustrated in Figure 4. Major existing hydropower facilities are noted in the figure as well.

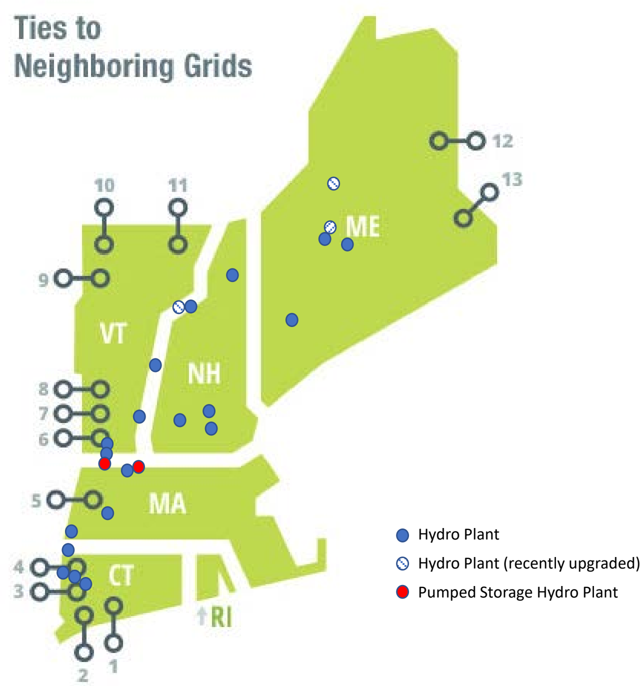

Figure 4. Existing hydropower facilities and connections of ISO-NE to other balancing authorities of Northeast Power Coordinating Council. ***Source: ISO-NE (2021)***

The interconnection with New Brunswick is double-circuit, 345-kilovolt AC, capable of delivering 1,000 MW to New England. The two interconnections to Quebec are both HVDC; one tie can deliver 2,000 MW to Massachusetts, and the other tie can deliver 225 MW to Vermont. These ties primarily deliver imported energy to New England. It is rare for energy to be exported to the Canadian provinces.

The New England–to–New York interconnection is a series of AC interconnections and one HVDC facility. The AC ties can deliver 1,400 MW to New England. These ties are bidirectional, and power routinely flows back and forth between the two regions, depending on market conditions. There is also a single HVDC interconnection between New England and Long Island; generally, energy flows to Long Island.

2.6 Proposed New England Transmission

The ISO-NE transmission interconnection queue contains a significant number of HVDC and high-voltage alternating current (HVAC) proposals. These projects fit into two major categories: interconnections to neighboring BAs and internal New England transmission additions.

Transmission proposals to neighboring Canadian BAs are primarily HVDC and are designed to provide additional import capability into New England. These facilities would allow hydroelectric power and renewable resources from the Canadian BAs to be delivered to New England. The extent of these facilities to operate in a bidirectional mode (allowing exports from New England to the Canadian provinces) has not yet been established. There are also proposals to add additional transmission between New England and New York. This transmission would be both HVDC and HVAC and would be bidirectional.

Various internal New England proposals would improve delivery of renewable energy from northern New England and from offshore wind energy facilities to the load centers in southern New England, alleviate potential transmission constraints in delivering additional external energy from the Canadian provinces, and augment transfer capability on existing congested internal New England regional corridors.

At this time, there is enough uncertainty that one cannot firmly project exactly what facilities will be built. A prime example was the proposed Northern Pass HVDC tie between Hydro Québec and New Hampshire. Northern Pass was approved for construction by ISO-NE yet was unable to garner the necessary state siting approvals. As a result, it was eventually canceled. It is expected that at least some of these proposed transmission projects will eventually be constructed, but it is highly unlikely that all will be built. Any new inter-BA ties that do get built will represent a significant increase in the energy import capability into New England.

2.7 Hydropower's Role in Today's Operation

Currently ISO-NE operates the wholesale electric market in New England, comprising:

- Energy markets for buying and selling day-to-day wholesale electric power:
    - The Day-Ahead Energy Market procures energy the day before delivery.
    - The Real-Time Energy Market balances the dispatch of generation and demand resources in real time to meet the instantaneous demand for electricity.
- Capacity Market for ensuring long-term system reliability.
- Ancillary services market to ensure short-term system reliability:
    - The Regulation Market compensates resources in real time to vary energy output to maintain system frequency.
    - The Forward Reserve Market compensates resources for keeping energy in reserve that can be provided to the system within 10 to 30 minutes to recover from contingency events in real time.
    - Real-time reserve pricing compensates resources for operating in a ready-to-respond state to vary real-time energy delivery/reduction as needed.
    - Voltage support compensates resources for maintaining dynamic voltage-control capability to maintain transmission voltages within acceptable ranges.
    - Black-start capability compensates specific power plants at key locations for their ability to restart the transmission system following a blackout.

Generating resources rated above 5 MW are obligated to offer their resource into the energy market. Participation in the capacity and ancillary services markets is optional. Resources bid into the Day-Ahead and Real-Time Markets wherein they are evaluated by security-constrained dispatch tools.

Operation of all hydropower facilities in New England has been evolving over the last decade. New England has added numerous high-efficiency combined-cycle natural gas resources, which are supplied with low-cost natural gas from the Marcellus Shale fields in Pennsylvania and Ohio. Coupled with growth in zero-carbon renewable resources, the result is energy pricing that has deviated from traditional trends. The example day shown in Figure 2 illustrates the correlation to lower wholesale energy prices associated with the "duck curve." Overall, wholesale prices in New England have dropped recently. There are multiple drivers for this price depression, with the primary driver being the reduction in natural gas prices, which accounts for about 90% of the change (Mills et al. 2019). The report notes that "growth in wind and solar impacted time-of-day and seasonal pricing patterns, growth in the frequency of negative prices was correlated geographically with deployment of wind and solar (Figure ES-2), and negative prices in high-wind and high-solar regions occurred most frequently in hours with high wind and solar output." This impact is expected to grow as these resources increase. Because hydropower resources participate in the wholesale market just like any other resource, hydropower owner/operators have had to adjust their bidding strategies to keep pace with changing price patterns and balance water management, facility safety, equipment wear and tear, spring freshet, and a host of other variables. These challenges will only continue to grow.

2.8 New England Market Pricing Trends

The Internal Market Monitor "2019 Annual Markets Report" provides some insight into two key financial income streams for all resources in the region. Natural gas generators, which supply approximately 45% of total regional energy needs, are the single largest resource type in New England. Because of that market dominance, natural gas prices are a primary driver of the energy price and other supporting markets in the region. The chart in Figure 5 shows the relationship between natural gas prices and the New England cost of energy, net commitment period compensation,[1] ancillary services, capacity, and the regional network load both in total annual market cost and in dollars per megawatt-hour. If future natural gas prices and availability remain relatively stable, the New England markets should remain relatively stable. However, with the introduction of ever-increasing amounts of weather-dependent zero-carbon renewables, it is not clear that natural gas prices will continue to dominate energy prices. In the future, stable natural gas prices may not correlate to stable energy prices, at least not for periods when those resources are not the dominant source of supply. So-called price-formation becomes a challenge, and it is unclear how that will affect all market participants, including hydropower.

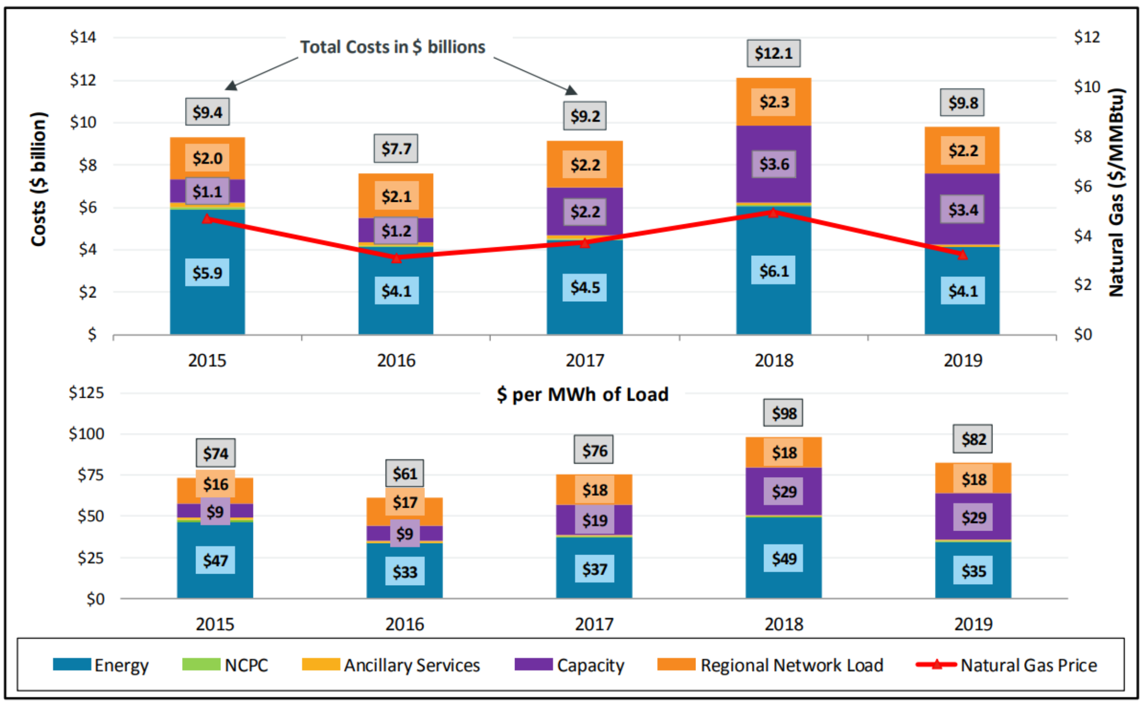

Figure 5. Energy and total costs for ISO-NE. ***Source: ISO-NE (2019)***

NCPC = net commitment period compensation, MMBtu = metric million British thermal unit

[1] Net commitment period compensation is the payment made to a market participant to cover any costs they may incur (make whole) when being run out of merit.

The Forward Capacity Market (Figure 6), which procures the necessary regional capacity to meet load-serving obligations and reserve requirements on a forward 3-year auction basis, has shown a steady decline in clearing prices over the last six auction periods. ISO-NE has struggled to implement changes in the capacity market over the last few years to address distortions and price suppression from resources participating in the auction that have out-of-market revenue streams. This is a somewhat universal issue among many of the market system operators that have capacity markets and has been discussed at the Federal Energy Regulatory Commission (FERC) in numerous capacity-market proceedings.

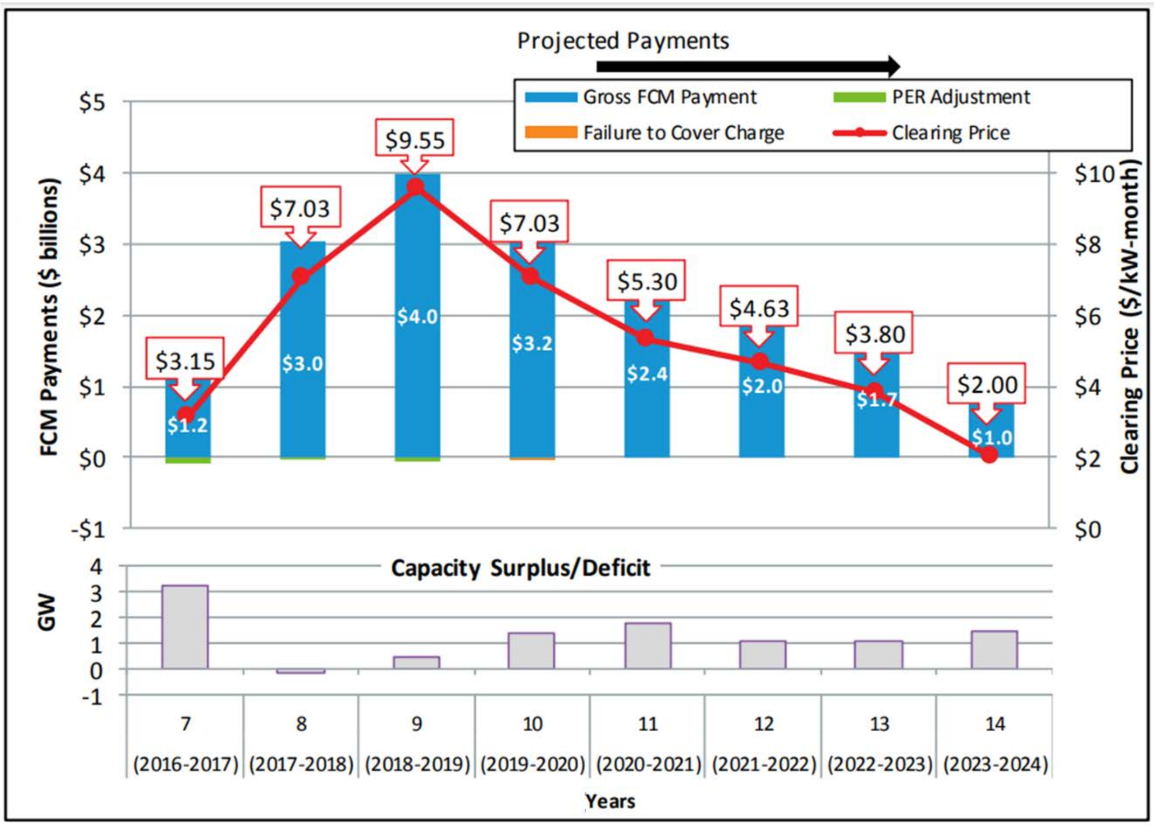

Figure 6. Capacity prices and revenues for ISO-NE. ***Source: ISO-NE (2020)***

CCP = capacity commitment period, FCM = Forward Capacity Market, PER = peak energy rent.

2.9 Dispatching a System With Large Penetration of Renewables

In the future, dispatching the system with ever increasing penetrations of variable renewables will be challenging. Table 2 shows one possible surplus capacity scenario for a typical spring day in 2029. It assumes all planned additions for 2029 based on the 2020 CELT report are constructed. Various resource unavailability assumptions for a typical spring day are factored in. The table shows a potential scenario with an excess of 10,000MW of online capacity that would need to be dealt with.

Table 2. Possible 2029 ISO-NE Resource Mix

Resource Type (power rating and output in MW)	Potential 2029 Nameplate Resource Mix (2020 CELT and New Generation Interconnection Queue)	Potential Available Resources Daytime Spring Light Load
Combined Cycle – CC	17,252	8,626[a]
Fuel Cell – FC	57	29 [a]
Gas Turbine – GT	4,024	2,012 [a]
Hydropower (Daily or Weekly Pondage) – HDP/HW	1,340	1,340 [b]
Hydropower (Run of River) – HW	733	733[b]
Internal Combustion – IC	100	50 [a]
Battery – ES/BAT	2,100	-2,100 [c]
Pumped Storage – PS	1,778	-2,150 [c]
Photovoltaics – PV	4,924	4,924
Photovoltaics/Battery Hybrid – PVSUN	424	-212 [c]
Steam Turbine – ST	9,432	4,716 [a]
Wind (Land-Based) – WT	2,377	428 [d]
Wind (Offshore) – WT	11,411	3,423 [e]
Total Resources	55,952	21,819
Assumed Spring Load Forecast Based on 35% of 24,755 Net Summer Peak With Behind-the-Meter PV and Energy Efficiency		8,664
Assumed Online Reserve Requirements		3,000
Surplus in Available Capacity		10,155

[a]Assume 50% of these resources are unavailable due to scheduled spring maintenance
[b]Assume spring freshet and 100% of hydropower availability
[c]Assume BAT and PS are in full recharge/pump mode
[d]Assume 18% capacity factor for land-based wind
[e]Assume 30% capacity factor for offshore wind

Postulating what a "future" May 2, 2029 day might look like by revisiting a "past" May 2, 2020 day, gives a dramatic view of the challenge (Figure 2). First, assume representative wind production from the proposed 11,411-MW off-shore wind projects based on the National Renewable Energy Laboratory (NREL) National Dataset Toolkit (NREL 2021) for wind plants off the New England coast. Then, factor in the growth in behind-the-meter solar energy and an additional 3 GW of utility-scale solar energy as anticipated (per Table 1). Using May 2, 2020, as a representative spring day, the combined effect of increased behind-the-meter solar energy, utility-scale solar energy, and new offshore wind energy on a typical windy day is shown in Figure 7. Midday, the net ISO-NE load when accounting for these additional zero-carbon resources (absent additional possible production by land-based wind facilities), is about negative 11,000 MW, which is consistent with Table 2. The generation ramp from midafternoon to midevening is almost 20 GW. These are daunting operational challenges.

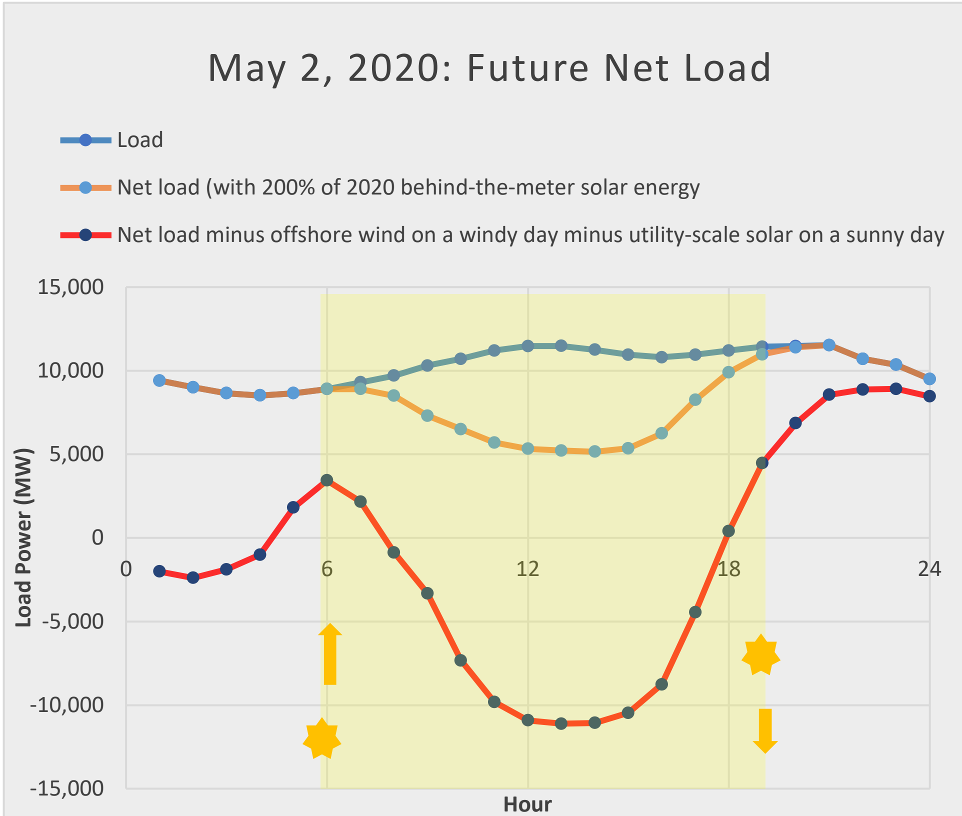

Figure 7. Combined solar power and offshore wind power impact on net load

Another complication would be the potential addition of transmission interconnections with neighboring Canadian provinces. If any number of the proposed interconnections in the current planning queue are built, the import capability of external low-cost hydropower and other renewables will increase. The addition of these external resources to the New England resource mix could exacerbate off-peak operations, negatively impact ramp requirements, increase excess energy periods, and further displace existing synchronous generating resources.

2.10 Essential Reliability Services

Over the past decade, the North American Electric Reliability Corporation (NERC) has studied the need for essential reliability services (ERS), and the impact on ERS as penetrations of zero-carbon resources increase. A report that defines what critical ERS are and why they are important considerations in reliable operation of the bulk power system was published in 2015 (NERC 2015). The report discusses in detail the need for adequate system inertia, primary frequency response, voltage and reactive support, black-start capability, and short-circuit strength (weak grid).

2.11 New England Operational Challenges

ISO-NE will continue to deal with growing operational issues because of the changing resource mix within the region, the increasing penetration of variable renewable resources, and the impact of exceptionally low net-load growth. This is highlighted by the documented growing frequency of the regions' exposure to the duck curve, which introduces several significant operational challenges. Periodic overabundance of zero-cost renewable energy will make it difficult to construct a least-cost dispatch. At times, ISO-NE will have to commit uneconomic resources or conversely decommit economic resources to maintain reliability. Many of the renewable resources will be clustered in remote regions, which may exacerbate congestion on the transmission system, challenging the ability to develop a least-cost security-constrained dispatch. The variability of wind and solar energy can prove to be very demanding in a real-time operating environment when those resources represent a major portion of the supply. These challenges can be greater when the resources are geographically close and may lead to the need for more agile balancing resources.

There can also be significant ramping issues in operations. When large amounts of solar energy resources begin ramping out later in the day, coupled with the increased evening energy demand, substantial amounts of flexible resources must be committed on the system to respond to the rapidly increasing generation/load imbalance. Ramping challenges can also occur during the morning as solar energy and load increase, especially when they are not well-synchronized. These challenges have been well-documented in California and other solar-rich systems. Wind-driven ramping events will be challenging under conditions when a large fraction of the region's power comes from huge offshore wind power plants subject to the variability of the wind.

Another byproduct of increasing the amount of zero-carbon renewable resources on the system is the impact on the current synchronous machine resources in the region. As renewables are added, they will inherently displace existing fossil-fuel synchronous machine resources, forcing their eventual retirement. Unmitigated loss of the present synchronous machine resource base in the region will have a negative impact on the reliability of the system. Their retirement will potentially reduce the primary frequency response within the region, exacerbate weak grid complications in various locations across the system, challenge the voltage and reactive performance of the system, and potentially introduce complications in the regional system restoration plan.

The scale of these challenges is large, and while conventional hydropower is not the only answer, it can play a significant role in mitigating those challenges.

3 Hydropower's Value in Providing Necessary Solutions in a Low-Carbon Future

There are a number of opportunities in which hydropower resources can provide significant benefits for the future decarbonized New England power system. Most of these apply to other similar systems in North America and beyond. The following provides a summary of those opportunities by category.

3.1 Hydropower and the Changing Supply of Essential Reliability Services

With the radical change in generation portfolio, the type, location, and availability of ERS will change. As noted, for example, under conditions wherein the majority of power for New England comes from offshore wind power plants, generation resources that have traditionally supported the grid will be under acute economic pressure to decommit. This leaves holes in the supply of ERS. It is well-understood (NREL 2013) that state-of-the-art inverter-based generation can provide many, if not most, ERS. But there are locational, temporal, and market challenges to be addressed, and some of the holes cannot be filled with even the highest performance inverter-based generation. Hydropower, regardless of type, can make significant contributions in support of ERS.

3.2 Managing Frequency

The ability of the power system to maintain 60 hertz (Hz) is determined by combining synchronous inertia and primary frequency response. In the current New England system, these two critical ERS are primarily provided by existing synchronous resources. The ability of these synchronous resources to provide these services arrests the decline in frequency after a system contingency and returns the frequency to 60 Hz. As synchronous resources retire or are dispatched off the system by the influx of zero-carbon resources, the ability of the region to recover and maintain frequency after contingencies may be jeopardized. The industry recognizes that various renewables, such as solar energy, wind energy, and battery storage, can provide these ERS; however, there is no current requirement mandating the provision of these ERS by renewables in New England (some systems, notably the Electric Reliability Council of Texas, require all generation, including wind and solar energy, to provide these services). Regardless of whether ISO-NE adapts this requirement, the region will continue to rely on the remaining synchronous machine resources, including hydropower, to provide such services.

The NERC Frequency Response Initiative Report (NERC 2012) provides one of the definitive references on the present practices and challenges of frequency control. There is a wealth of new and relevant material published on the topic. Hydropower has and will continue to play a valuable role in managing frequency.

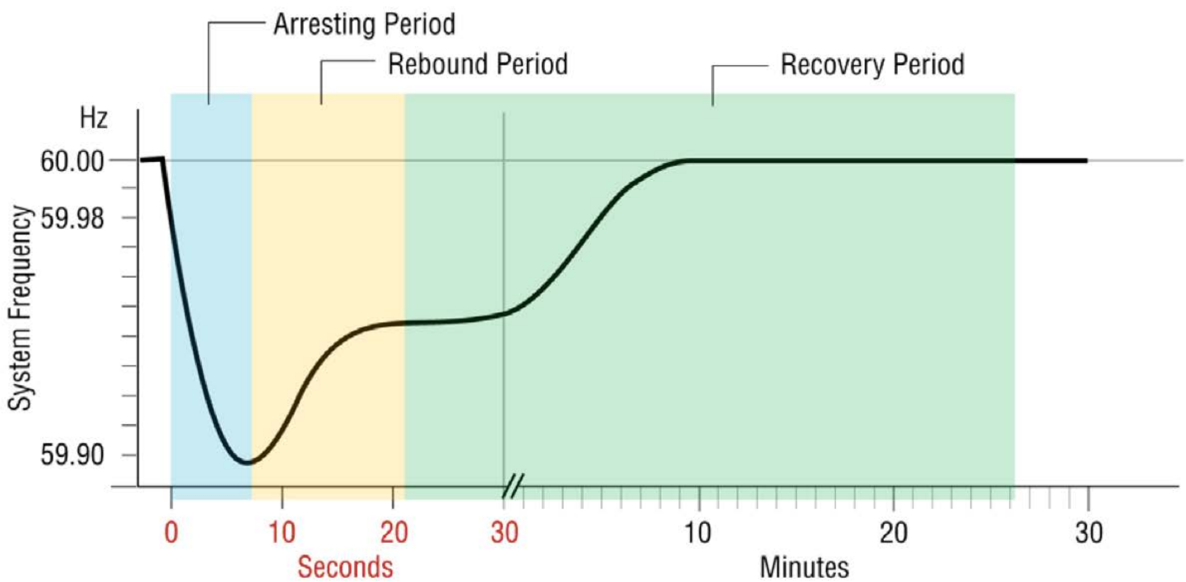

Figure 8. Frequency control time periods. ***Source: Eto et al. (2010)***

Today in ISO-NE, typical synchronous machines, including hydropower generation, are at the center of the temporal sequences shown in Figure 8, with the shaded areas defined as follows:

- The blue shaded area, the "arresting period," refers to synchronous generators providing inertia, which inherently limits the initial rate of change of frequency (RoCoF) after a disturbance. The lowest point in the frequency drop is called the nadir, which occurs around 5 seconds after a disturbance.
- The yellow shaded area, the "rebound period," refers to autonomous primary frequency control (PFC) by governors on droop control, with some units formally holding headroom (as compensated by "spinning reserve" market functions) as well as fast centralized secondary frequency control automatic generation control (AGC) from some synchronous generators that participate in the regulation market.
- The green shaded area, the "recovery period," refers to economic redispatch as tertiary control to rebalance and reposition the system to make it ready for the next event.

The changing resource mix in New England will substantively alter the system behavior in each of these time frames. Hydropower's contribution in each of these time frames will become more valuable, and future investment in newer hydropower technology can increase that contribution. Higher levels of functionality, with particular emphasis on exploiting ways that hydropower would work with, enhance, and enable growing ERS supply from inverter-based resources (IBR) are a key element of that leverage.

3.2.1 Arresting Period: Inertia and Fast Frequency Response

Following a system disturbance wherein load and generation become imbalanced, frequency immediately begins to decline. The RoCoF is dependent on the size of the event (i.e., how many megawatts are lost) and the online system inertia. During the arresting period (blue in Figure 8), online resources must stop the decline in frequency before it reaches levels that will disconnect customers via underfrequency load shedding. Underfrequency load shedding sets a minimum acceptable frequency to protect the system from collapse and is typically set below the frequency nadir for design-basis events. The NERC rules governing frequency response assign a "frequency response obligation" to each BA. The frequency response obligation rules mandate speedy response such that each BA carries its share of the burden to avoid unacceptable underfrequency load shedding actuation across the interconnection. Because hydropower generation is synchronous, it will continue to provide increasingly scarce inertia in the future. Additionally, newer variable-speed pumped storage hydropower (VSPSH) has the potential to offer significant amounts of fast frequency response (FFR), a separate service that acts rapidly to help in the arresting period. Fast frequency response is emerging as a paid ERS in some systems.

3.2.2 Rebound Period: Primary Frequency Response

Primary frequency response from synchronous machines including hydropower and pumped storage, also known as governor response, is an important part of ISO-NE operations. After the arresting period, the system must recover to 60 Hz. This recovery is accomplished by the governor response of the online operating generators (yellow in Figure 8) and by the procurement of spinning reserve (green in Figure 8). The combination is important, because governor response is a finite quantity based on the online unit characteristics, whereas spinning reserve is a quantity predetermined and kept online in reserve. The portion of response that will occur during the arresting period can be calculated; therefore, the needed amount of spinning reserve can be determined. Thus, the arresting needs are addressed, but market differentiation for the resources that act faster is absent.

Only generators that operate at less than their maximum power output, commonly referred to as headroom, can provide primary frequency response service. Today, ISO-NE, unlike the Electric Reliability Council of Texas and Hydro Québec, does not require fast frequency response or primary frequency response from inverter-based wind energy and solar energy generation, even though the ability to provide these services, if required, is mandated by FERC. Therefore, the primary source of these services will depend on the headroom maintained on the online synchronous machines. Hydropower resources operating with headroom can play an increasingly integral part in the region in maintaining adequate fast frequency response and primary frequency response.

3.2.3 Recovery Period: Secondary Frequency Response (Automatic Generation Control and Regulation)

The fastest centralized frequency control function comes from the system AGC. Individual generating units provide this compensated service, receiving signals at about 5-second intervals from the grid operator's energy management system. Non-run-of-river hydropower and pumped hydropower (when in generation mode) facilities participate in this market today. As with primary frequency response, ISO-NE does not use wind and solar energy generation to provide AGC. Not all plants are mandated by FERC to have the capability to accept AGC signals, so while some systems with high levels of wind energy allow them to participate in AGC, ISO-NE does not. The role of hydropower in providing AGC is likely to change somewhat as it becomes (nearly) the sole synchronous resource in operation at times.

3.3 Maintaining Healthy Voltages

Voltages on the bulk power system must be maintained to ensure system reliability and move power where it is needed during normal operations and following contingencies. Managing reactive power resources in the system facilitates necessary voltage control. The complication in this is the localized nature of voltage control: Issues tend to be local in nature, and as such, require local provision of reactive power to address voltage excursions. Currently, reactive power and subsequent voltage control are primarily provided by the existing synchronous resources that are electrically dispersed across New England. As the region sees an increase in inverter-based renewable resources, they can provide voltage support as mandated in FERC Order 827. The potential problem facing the New England system in the future arises from the geographic location of these new inverter-based resources. If one assumes a significant amount of offshore wind energy resources are constructed, based on the dispatch of the system and the load level, those resources become the primary source of reactive power during many hours of the day. This means the provision of reactive support to maintain voltage would be localized at the offshore wind resources, electrically remote from portions of the transmission system. The lack of geographic diversity in reactive power supply may prove to be problematic in keeping the grid voltage healthy. The NERC Essential Reliability Services task force (NERC 2015) noted that this strong locational element makes it difficult to create good markets for voltage support services.

Recognizing these locational challenges, many of the existing hydropower facilities are in more vulnerable locations, such as remote, electrically weak parts of the system. Today, hydropower already plays a key voltage support role in various subareas within the ISO-NE system. Going forward, with more inverter-based resources displacing traditional fossil-fuel synchronous machines, the value of the reactive power capability and geographic/electrical location of hydropower facilities will increase, which might alter the economic calculus.

3.4 The Role of Hydropower in Black Start and System Restoration

History has proven there is a periodic risk of major system blackouts. NERC (2006) requires that systems be prepared to recover from significant system blackouts. The industry commonly refers to the process of taking a system that has been blacked out and returning it to its normal operating condition as “system restoration.” This is a detailed, complex, and rigorous step-by-step process of starting up generating resources, reenergizing transmission and distribution systems, and reconnecting load. System restoration requirements are covered under NERC standards. NERC requires ISO-NE to have a comprehensive plan, detailing how the system would be rebuilt from the top down after a system blackout. “Top down” refers to the restoration priority of facilities on the bulk power system; priority is given to the high-voltage transmission backbone, the off-site power supply to nuclear power resources, and the reestablishment of transmission ties with neighboring reliability coordinators (New York, Quebec, Maritimes). The portfolio of conventional synchronous generating resources that ISO-NE relies upon for putting the grid back together is a combination of existing synchronous resources that include both hydropower and fossil-fuel facilities. There are two types of generating resources involved in system restoration: generators that are capable of black start (i.e., they can bring themselves online without any external energy or voltage support from other resources) and generators that depend on black-start units to provide them with both energy and voltage support for restart. Therefore, those generating resources that are black-start capable are the initial fundamental building blocks of any system restoration plan. The portfolio of conventional synchronous generating resources that ISO-NE relies upon for putting the grid back together includes use of hydropower facilities as well as a variety of fossil-fuel plants. Presently, ISO-NE does not have a requirement for inverter-based renewable resources to provide various black-start services, which may make system restoration problematic during certain future high-renewable dispatch conditions. Hydropower is a key element, especially in the more remote parts of New England. Its value for this service can be expected to grow.

3.5 Hydropower and Declining Effective Short-Circuit Strength

Another key ERS consideration is the strength of the transmission system, commonly referred to as the short-circuit strength of the system. NERC and the broader industry have given substantial attention to the vulnerabilities of inverter-based resources in areas with low "effective" short-circuit strength.[2], which has been documented in several published reports (NERC 2018). Areas with an inherently weak transmission system and few committed synchronous generating resources are susceptible to low effective short-circuit strength. As solar, wind, and battery resources displace existing synchronous machine resources that contribute to system strength, concerns about overall system strength and the ability to stably respond to disturbances will increase. The electronic control logic used by inverter-based generating resources is prone to misoperation when these facilities are connected in areas with low effective short-circuit strength. For example, land-based wind installations in New England are in remote areas of the system where they can take advantage of good wind conditions. Several of these areas also have low effective short-circuit strength. Hydropower units in these areas can help increase the system strength, thereby supporting more reliable operation of the inverter-based resources. At this time, ISO-NE has not conducted a detailed analysis of the potential impact on short-circuit strength of the system as significant inverter-based resources are constructed and synchronous machines are retired.

3.6 Lowering the Floor: Hydropower's Role in Relieving Dispatch Anomalies Constraints

In future ISO-NE operations, the large fleet of wind and solar energy generation should be able to meet many of the system ERS needs if mandated by ISO-NE interconnection requirements or incented by future ISO-NE market development. Clearly, under conditions for which there is an insufficient supply of ERS (of the right type, in the right locations, or for the right price), dispatch anomalies will result in conventional fossil-fuel generation being committed in order to maintain reliability. This out-of-merit commitment leads to inefficiency in the market and subsequent dispatch. Specifically, when there's enough zero-marginal-cost, zero-carbon resources to meet system needs, but the system is security-constrained, there are adverse cost and emissions impacts. The worst anomalies are cases in which ISO-NE would need to keep uneconomic fossil-fuel units dispatched on the system to cover ERS shortfalls, or, conversely, wind or solar energy resources would have to be decommitted to manage overgeneration and other reliability constraints on the system.

[2] Effective short-circuit ratio accounts for the aggregate rating of multiple inverter-based resources in close electrical proximity.

The use of existing and higher functionality hydropower presents opportunities to mitigate some of those constraints. This is a situation wherein the broad capabilities of hydropower have the potential to leverage benefits far beyond the individual hydropower unit megawatt ratings.

Hydropower through optimal water management of run-of-river assets, managing assets with pondage, and appropriate dispatch adjustments to PSH can help eliminate some dispatch anomalies. Several considerations are:

- Hydropower can be held in reserve, thereby increasing overall system spinning reserve, which can provide added value in addressing the variability of the renewable resources and help address ramping issues by providing more system generation flexibility. The result is a reduced dependence on fossil fuel assets. The ability to either store water at critical times or utilize the water to generate power at critical times provides an immense amount of flexibility to system operations and can address a number of operational challenges.
- As discussed in Section 2.10, voltage/reactive support of this system is very localized. There are cases in which fossil-fuel units may be committed as reliability-must-run generation to manage voltage/reactive issues in various areas of the system. Again, effectively managed hydropower assets in those areas can be utilized to mitigate these issues, thereby lessening dependance on fossil-fuel assets. This may also include operating assets that have the capability to operate in synchronous condenser mode. These water management and dispatch decisions can also be used to leverage hydropower assets to increase short-circuit strength as well as help with voltage/reactive issues.
- Novel control of hydropower, aimed at reducing transmission congestion and relaxing stability limits, could also result in fewer dispatch anomalies. This is especially the case for VSPSH, as discussed next.

3.6.1 Variable-Speed Pumped Storage Hydropower

One of the major and most exciting new options for frequency control comes from pumped storage hydropower. The introduction of variable-speed technology creates a spectrum of new and improved performance. Some of these are well-recognized and are documented in (Botterud, Levin, and Koritarov 2014). Unlike conventional pumped storage hydropower (including Northfield Mountain and Bear Swamp in New England – see Figure 4), new VSPSH can provide primary frequency response and fast frequency response during pumping. This could be a huge benefit for system operations. Generally, pumping occurs when other sources of primary frequency response may be limited, such as lighter system load conditions when many synchronous machines are offline and inverter-based generation is high. So, in addition to providing a sink for excess power during high water/wind/solar conditions, VSPSH supplies needed primary frequency response and fast frequency response. Those capabilities are significant advantages that VSPSH provides that can address the decommitment of fossil fueled generation that might otherwise be committed to provide primary frequency response.

VSPSH is especially attractive for this class of control for several reasons. The power electronics that enable variable-speed operation provide higher efficiency in both generating and pumping mode and give wider dispatch range with lower power dispatch. Transient delivery of a large fraction of the machine rating within a second is possible with VSPSH with high precision. This agility also reduces the mechanical and electrical stress associated with load rejections, so VSPSH can “block” essentially instantly, giving huge step response for large disturbances. The latest VSPSH technology is capable of changing modes rapidly (Maruzewski et al. 2016) from pumping to generating. This capability effectively makes the spinning reserve value of VSPSH double the nameplate rating when it is in full pumping mode.

Other creative exploitation of VSPSH agility could introduce transient stability benefits in New England. For example, it is possible that VSPSH in the right location with customized controls could relieve some stability-related transfer limits within New England and with neighboring systems.

3.7 Investing in Existing Pumped-Storage Hydropower and Conventional Hydropower

The PSH operating in New England is highly valuable for system operation and has served the system well for decades. Northfield Mountain and Bear Swamp have recently undergone extensive rebuilds, ensuring their continued contribution to the system for decades going forward. The 1,000-MW Northfield Mountain facility will be 50 years old in 2022 and is relicensing for another 50 years. The Bear Swamp facility will be 50 years old in 2024. It received FERC approval for a 66-MW upgrade to 666 MW in 2008, which is now complete.

Several of the other large hydropower facilities, like Wyman and Harris in Maine and Comerford in New Hampshire (noted in Figure 4), have gone through extensive rebuilds as well. Investment in existing resources to increase output and improve flexibility is possible, but further incentives may be needed for other hydropower facilities to upgrade.

Lowering the minimum power of the hydropower units themselves may have benefits in relieving overgeneration constraints. Investment in the evaluation of hydrodynamic constraints that set minimum power has the potential to allow lower limits if externalities of minimum flow allow. The computational fluid dynamic codes that determine operating zones with risk have advanced (Bechtel and Fabbri 2014), allowing "exclusion" zones to be refined and reduced, and the wear costs of operation in them to be better understood.

Constraints from regulatory classification can be important. Rationalizing investment in existing pumped storage hydropower can follow various paths. In one recent refurbishment (outside of New England), the resource was reclassified so that it was "freed up" to provide more valuable ERS. In that case, the owner approached their regulator and got the plant reclassified as spinning reserve so they could decommit coal at night to reduce wind curtailment, with the PSH providing ancillary services.

3.8 Constraints on Hydropower Operation: Observed Trends

The flexibility of hydropower resources to provide a variety of ERS has been discussed in this report. However, some caution is necessary in projecting the increased or even further use of some attractive features as status quo. Operations that substantively change the power production of a hydropower plant obviously change the water flow. This change in flow imposes mechanical stresses on components of the hydropower plant. More importantly, and often outside the discussion of grid operations, these changes in flow have environmental effects that cannot to be ignored. Concerns about wildlife impact, shore erosion, and oxygenation, to name a few, have been raised in connection with highly variable flows.

Licensing and relicensing of hydropower facilities by FERC require due diligence and stakeholder input on a wide spectrum of concerns. Environmental concerns are rightly front and center. For example, in recent years (Smallheer 2021), during the relicensing of three hydropower facilities in New England, concerns about these effects led to tighter operating constraints on future operation of the plant. As presently proposed, after relicensing, the facility will be prevented from significant cycling, forcing them to essentially operate as run-of-river most of the time. The stakeholders agreed that access to operational flexibility should not be eliminated altogether, so provision was proposed for occasional use of the plant's full flexibility by the grid operator, particularly under emergency conditions. It appears these types of relicensing caveats tend to push the grid operator away from using hydropower in everyday balancing and instead leave it for more extreme circumstances. It is not clear whether these constraints will have substantive effect on the value to the system or the revenue streams to the owners in future. In the context of resource adequacy, the constraints of the example relicensing appear to have sufficient flexibility to not degrade the subject plant's contribution.

3.9 Address the Overgeneration Challenge

The simple examples provided here illuminate serious operational challenges as the penetration of variable inverter-based resources increases. For the examples presented, there will be long periods of excess generation availability in the New England system. The excess generation may exceed 10 GW, or 40% of the system peak load. These periods of high wind and solar energy production may correspond to periods of critical shortages of ERS supply. The dispatch of a future system with existing and potentially future PSH (in particular, VSPSH) could prove valuable to system operations by providing much-needed storage capability, generator flexibility, and supply of ERS that will be required to maintain reliability and resiliency. Three actions related to hydropower will help address the challenges that accompany overgeneration:

- **Support and add PSH/VSPSH**. One of the critical challenges for New England is to technically and financially support the continued operation of existing PSH in the region. The high volume of filings before the FERC regarding perceived market deficiencies and supporting proposed market changes especially regarding the various capacity markets is evidence that current market mechanisms may fail to support existing PSH. Changes may be required to incent existing PSH to continue operating in the region. Further, the region should develop the necessary mechanisms to incentivize development of future PSH and specifically VSPSH.
- **Expand cooperation with neighboring systems**. The potential issues facing New England highlighted in this report are not unique to the region. The high volume of renewables proposed for surrounding balancing authorities means this is a much broader industry issue. While there is a challenge in New England to expand PSH/VSPSH, which will benefit New England directly, these assets can inherently provide benefits to the neighboring systems. Creating market mechanisms to allow the generating capability, energy storage capabilities, and operational flexibility benefits of PSH/VSPSH located in New England to also benefit neighboring systems via the existing transmission interties would enhance the justification for building new PSH/VSPSH facilities.
- **Reduce the need for ISO-NE to uneconomically dispatch the system**. ISO-NE must reduce the need in the future to rely on uneconomic dispatch choices to maintain system reliability. Periods of excess generation, significant evening ramps, continued need for

adequate levels of inertia and primary frequency response, the need to maintain adequate reactive and voltage support, and other constraints (both within and outside New England) may require various forms of uneconomic, inefficient dispatch to ensure system reliability in real time. This huge challenge warrants active pursuit of both technical and market methods to allow greater hydropower dispatch flexibility and addition of PSH/VSPSH. Significant cost savings and decarbonization benefits may result.

3.10 Paying For It All

The preceding sections have postulated a lengthy list of benefits that hydropower technology might offer in a future ISO-NE system, allowing the entire system to run more efficiently and economically with lower carbon emissions and higher reliability and resiliency. Yet, for many of those functions, the value will accrue to the system as a whole, not to the owner/investors of the hydropower facilities. In many regards, the benefits that hydropower brings to the system today are uncompensated. Compensation mechanisms are needed for hydropower asset owners to address instances where adaptation of operating practices that benefit the grid as a whole come at the expense of the asset owner. Investment in plant capabilities that benefit the entire power system must be incentivized in some fashion. In simple terms, there are two major market options possible:

1. **Create a competitive market for ERS**. The primary goal would be to define market products like flexible output (e.g., ramping services) or primary frequency response. These various reliability services that ISO-NE will require going forward need to be technology-agnostic. Then, ISO-NE would need to create a competitive market that would allow all resources to equally compete to provide each service. Existing and potentially new hydropower could then compete with other technologies, thereby enhancing potential future revenue streams.
2. **Define the various ERS system needs in type, timing, and volume**. ISO-NE would need to determine which generating resources could provide the services and what the least-cost option would be to procure them from those resources. ISO-NE would then create a direct payment mechanism that would compensate resources for providing those services when called upon by ISO-NE operations.

These two choices represent the procurement of necessary reliability services via a purely market solution or using ISO-NE responsibilities as the reliability coordinator for the region and using a "command-and-control" mechanism to procure the services. When one considers the breadth of the industry, there are many arguments for just about every aspect of power generation and delivery. There are those that advocate the implementation of a competitive market mechanism to ensure a least-cost product for consumers. There are others that postulate that necessary reliability services must be procured and that the market cannot be relied on to adequately provide such services. It is not the intent of the authors to discuss the merits of either approach to obtaining services, but it must be understood that whichever path ISO-NE takes, approval and tariff filings would be required by FERC.

Any market initiative would be jointly developed by ISO-NE and the various New England stakeholders. Consensus proposals would have to be folded into the ISO-NE tariff and filed with FERC, who has the ultimate authority to approve, deny, or modify the proposal.

3.11 A New Look at Planning

Planning processes tend to ignore the potential for existing resources to provide new functions and benefits. They also tend to discount benefits that accrue to the system as a whole from both existing and new resources.

Standard planning processes should be augmented to:

- Evaluate the impact of hydropower on system stability and power transfer levels
- Evaluate the ability of hydropower to relax generation constraints that exacerbate the overgeneration problem
- Explicitly consider the contribution of inertia from hydropower (and potentially other critical ERS).

New system planning studies of existing resources should consider how higher performance can relieve stability limits and improve operational economy. This is different from more typical studies that generally focus on making sure that resources do not degrade performance. This is a recommendation to actively investigate possible systemwide benefits and include those benefits in evaluating options.

Stability studies are needed that specifically explore how dynamic performance features, such as better excitation, faster governor response, and improved voltage support contribute to remediating transmission line constraints or interface stability limits. Similarly, stability studies can be designed to determine if hydropower resources can remove a constraint that leads to a dispatch anomaly. Stability studies can also establish the performance needs associated with inertia, thereby establishing minimum synchronous inertia reserve levels, systemic trade-offs between inertia and fast frequency response (and other functional alternatives to inertia), and the subsequent impact on tie lines with neighboring systems.

Stability analysis can be conducted to quantify system wide benefits obtained via improved dynamic performance. Performance benefits can be in the form of relaxed constraints or limits. (e.g., increased power transfer limits, or reduction in uneconomic reliability-must-run requirements.) Typically, comparison of production cost simulations run in pairs – with and without the modified limits – will define operating cost and emissions benefits associated with the system wide benefits. Thus, both types of analyses, stability and economic, are needed to advise whether specific functionality makes economic sense.

Investments should be made in existing hydropower resources to maximize benefits that pass these criteria. Similar studies, early in the planning stages for specification and implementation of new hydropower and PSH should include explicit consideration of critical grid benefits. Mechanisms to measure and assure (and compensate) the provision of services that produce these system benefits are needed.

4 Summary

The role of hydropower in the operation of a future, decarbonized New England power system reaches far beyond the energy delivered. This report has explored ways in which hydropower can advance the reliability, operability and economy of the system. The recommendations provided above, and summarized here, have applicability to other modern systems with hydro resources that are decarbonizing. Successful development of the future New England system should consider these actions:

- Maintain and enhance supply of essential reliability services. Monitor projected availability of all ERS, including those for which formal markets are presently lacking, and reevaluate the of role existing and new hydropower in maintaining adequate supplies.
- Manage frequency. Fully evaluate frequency benefits from existing and new hydro resources, including the value of inertia, potential for improved dynamic response and fast frequency response from advanced pumped storage hydro.
- Maintain voltages. Fully evaluate voltage support services from hydro in future grid topologies, including consideration of reactive power upgrades and potential for synchronous condenser operating mode.
- Evolve blackstart. Monitor loss of traditional blackstart resources and provide economic incentives for hydro to maintain and possibly expand blackstart services.
- Maintain adequate short circuit strength. Include short circuit strength considerations in planning and create economic inducements for resources, including hydro, to provide short circuit support, including synchronous condenser operating modes.
- Lower dispatch minima. Create inducements for existing resources, especially fossil plants, to lower minimum dispatch constraints.
- Invest in existing PSH & hydro. Include potential upgrades and increased functionality of existing hydro resources during creation of long-term plans.
- Watch trends on constraints. Engage with non-hydro stakeholders to prioritize hydro flexibility for critical reliability functions and essential reliability services.
- Address overgeneration. Pursue added energy storage, especially advanced pumped storage hydro; expand cooperation with neighboring systems; reduce drivers for uneconomic dispatch.
- Pay for it. Create market or procurement mechanisms to fully value all the services from hydro and incentivize investment in existing facilities as well as constructing new facilities.
- Plan differently. Include active maximization of potential systemic benefits from existing, upgraded and new hydro resources.

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