NORTHFIELD MOUNTAIN PUMPED STORAGE:
Assessment of Contract Benefits in an Increasingly Renewable Region

Prepared by: Energyzt Advisors, LLC

Prepared for: FirstLight Power, Inc.

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For additional information, please contact:

Tanya Bodell, Executive Director: tanya.bodell@energyzt.com

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This report examines the value that large, grid-scale energy storage projects can offer Massachusetts and New England for the period from 2022 through 2030. Over the next ten years, wholesale power markets in the Northeast are projected to install a significant amount of renewable resources. As a result, peak and off-peak pricing patterns will change and variable output associated with renewables will create additional need for fast-ramping facilities. Energy storage is a means to optimize energy output by shifting generation to the hours when load requirements need to be met. Energy storage also can provide additional benefits in the form of reduced carbon emissions and energy prices through peak shaving. Current and projected energy market prices do not provide sufficient incentive to realize the full extent of those values, however, and are not projected to do so for the next ten years.

Specifically, Northfield Mountain Pumped Storage Project ("Northfield") provides an example of how grid-scale energy storage in New England can create value as renewable integration increases over time. Northfield is a large pumped-hydro facility located in western Massachusetts. Known as "New England's largest battery," Northfield uses water and gravity to charge by pumping water into a reservoir and discharges by producing hydroelectric power. Northfield operations can shave peak prices and reduce carbon emissions, resulting in a net benefit that effectively pays for itself. This dynamic makes Northfield a resource that provides net carbon emissions reductions for Massachusetts and New England, as well as for the entire Eastern Interconnect.

Using a production cost model with inputs that reflect day-ahead market operations, the analysis described in this report examines Northfield's impact on cost to load and carbon emissions if Northfield is contracted to provide a guaranteed amount of energy into the day-ahead energy market during high-priced hours each day as opposed to operating as a merchant plant. The results indicate that a grid-scale storage facility such as Northfield offers carbon emissions reductions, reductions in cost to load, improved energy security during the winter months, and fast-ramp capability that increasingly will be required for reliability.

This analysis also shows that the current state of the energy market does not allow for Northfield to fully realize the value that it can offer Massachusetts and New England. The social cost of carbon is not fully priced into energy dispatch, resulting in lower utilization of grid-scale energy storage facilities such as Northfield. In addition, the day-ahead energy market dispatch algorithm would not fully utilize Northfield to realize the potential reductions in cost to load that could benefit end-users. Contracting Northfield to operate more than what the Independent System Operator of New England ("ISO-NE") would dispatch in day-ahead energy markets can create additional benefits above and beyond those created by merchant operations.

Northfield offers a number of potential benefits to Massachusetts and New England. As a result of its large size and flexible operating profile, Northfield can offer Massachusetts and the broader New England region a number of valuable services simply by scheduling the plant to operate more frequently in ISO-NE day-ahead energy markets. Additional value that Northfield can provide under contract includes:

- **Carbon Emissions Reductions:** Given the generation mix of Massachusetts and New England through 2030, Northfield offers a means of reducing state, regional, and global carbon emissions. By pumping when the marginal electric generating unit emits zero or low carbon and generating to displace units that are more carbon intensive (e.g., gas, oil or coal units), Northfield reduces Massachusetts, New England and broader system-wide carbon emissions.

- **Peak Price Shaving and Reduced Cost to Load:** Northfield storage also can be used to reduce cost to load in Massachusetts as well as to the entire New England market. By contracting to generate during the highest-priced hours of the day, Northfield can shave peak prices and realize significant price reductions beyond what merchant operations would produce.

- **Improved Energy Security:** Northfield offers a means to reduce reliance on natural gas during winter months by pumping when more efficient resources are on the margin and dispatching when gas-fired peaking plants would otherwise operate. Northfield also can be used to displace higher carbon emissions associated with dual-fuel gas and oil units during winter months, helping those units remain within their permitted emissions limits.

- **Ramping Capability and Reserves:** As an increasing amount of renewables enter into the system, the need for fast-acting ramping reserves also increases.

Northfield's ability to ramp up production quickly protects against sudden drops in wind and solar energy supply. As renewables come online, ISO-NE will need to ensure that it procures adequate ramping capability to cover intra-hour and inter-hour losses of renewable generation. A contract with only a portion of Northfield's capacity allows it to continue to supply New England with fast-acting ramp services beyond the capability used to deliver peak shaving operations under contract.

These value propositions are not mutually exclusive, but can generate benefits simultaneously. In addition, Northfield's flexibility offers a potential contract counterparty the ability to use the storage asset to optimize whichever objective provides the most value during times when an alternative dispatch rule is most valuable.

Despite the value it can provide, Northfield's energy commitment in day-ahead markets is expected to remain low.

Northfield currently operates at less than one-third of its total potential generation output. Current market compensation structures that rely on economic dispatch to minimize total production cost do not optimize Northfield's potential benefits to Massachusetts or the New England markets. Specifically, the day-ahead energy market fails to realize Northfield's potential benefits for three reasons:

1) The ISO-NE energy market objective function is limited to minimizing total production costs.

2) Excess generation supply and lower natural gas prices reduce price volatility and day-ahead energy market dispatch of Northfield.

3) Higher price volatility tied to variable renewable generation output in dynamic supply conditions that change from day to day are more likely to occur in real-time markets, moving Northfield economic opportunities to real-time energy market sales.

As a result, Northfield is under-utilized and is projected to continue to be underutilized in day-ahead energy markets going forward.

Northfield's flexibility is not adequately incentivized or compensated in day-ahead energy market.

As a quick-response load and generating resource that also can be used to provide fast-ramping ancillary service reserves, Northfield offers the Commonwealth of Massachusetts and ISO-NE significant flexibility to provide energy security and reliability when it is most needed. This flexibility becomes increasingly important as Massachusetts and the northeast region move towards a power generation mix with lower carbon emissions. This flexibility value, however, is not adequately compensated in day-ahead markets which could benefit from a higher dispatch of Northfield energy.

Northfield's value propositions can be realized to a greater extent under contracted operations.

Northfield currently operates as a merchant plant and is only dispatched in the day-ahead energy market when the price for energy is sufficiently higher than the cost of electricity required to pump water into its reservoir and any opportunity cost of foregoing a real-time energy sale. As a merchant plant, Northfield provides value in the form of energy, capacity and operating reserves. Realization of such value, however, depends on market prices. When energy market prices are low, peak/off-peak ratios are compressed, and Northfield does not operate at its full operational capability. Without a contractual arrangement, carbon emissions reductions and reductions in cost to load opportunities and reduction in natural gas-fired generation will be unrealized.

If the plant were contracted to a third party, Northfield could provide a greater contribution to the system through more fully utilized storage throughput capability. Under contracted operation with two of Northfield's units guaranteed to generate a minimum amount of energy each day at the highest-priced hours in the day-ahead market, the contract could decrease carbon emissions while shaving peak prices and resulting in net benefits to Massachusetts and New England end-users.

A summary of the quantified value propositions and the relative magnitude of each based on the analyses described within this report are provided below. These benefits reflect the difference in Northfield's impact between operating as a merchant facility and dispatching under an assumed contractual structure. These benefits are additive, resulting in potentially hundreds of millions of dollars in value to Massachusetts and New England over the 2022 to 2030 period (**Figure ES-1**).

Figure ES-1: Summary Assessment of Northfield's Value Propositions Under Contract

	Estimated Impact 2022-2030	
Value Proposition	**New England**	**Massachusetts**
Reduced Carbon Emissions	73,000 to 260,000 metric tonnes / year under normal conditions, with an average of 181,000 per year for a total of 1.6 million metric tonnes from 2022 through 2030 Value: $900,000 to $2.7 million per year assuming $5 to $15 / tonne	Starting at 160,000 metric tonnes / year under normal conditions, and declining as renewables come online for a total decrease of around 876,000 metric tonnes from 2022 through 2030 Value: $1.5 million per year at $15 / tonne
Energy Price Reduction	$0.16 - $0.58 / MWh lower average price in day-ahead energy markets, for supply to all New England load, averaged across all hours	$0.15- $0.67 / MWh lower average price in day-ahead energy markets, supply to Massachusetts load, averaged across all hours
Total Net Reduction in Cost to Load	$412 million lower for New England load from 2022 through 2030, with an average savings of $45.8 million per year, with most of that savings (i.e., $265 million) occurring in the first five years	$220 million ($2018) in savings from 2022 to 2030, with an average savings of $24.5 million per year, with most of that savings (i.e., $141 million) occurring in the first five years
Energy Security	An average of 1,700 GBtu per winter season (November to March) of natural gas displacement under average conditions, displacing 0.5% to 4% of natural gas usage each season	Same benefit as New England since natural gas is a regional market

Furthermore, these benefits are available while still providing significant flexibility and ramping response from Northfield. The equivalent of five hours of daily dispatch at the highest hours requires only eight hours of pumping, which can be optimized using Northfield's four pumps at the lowest-priced hours. This allows the rest of Northfield to be used to meet increased ramping needs as renewable generation increases.

Northfield is a flexible asset that can create additional value in terms of carbon emissions reduction and reductions in cost to load going forward.

Northfield can provide numerous value propositions beyond what currently is incentivized by ISO-NE markets. Indeed, while Northfield's flexibility offers significant advantages to Massachusetts and the region, merchant dispatch of Northfield in the ISO-NE day-ahead energy markets is unlikely to achieve the full value of these benefits.

NORTHFIELD MOUNTAIN PUMPED STORAGE: Assessment of Benefits in an Increasingly Renewable Region

This report assesses the benefits of Northfield and how those benefits change as renewable resources increasingly integrate into New England's competitive wholesale electricity markets. Northfield serves as the largest storage facility in the New England system. By analyzing Northfield operations under anticipated changes in market conditions, insights can be made that apply to other New England storage assets.[1] The point of this analysis is to determine and quantify the value propositions that Northfield and potentially other grid-scale storage facilities can offer if they were better utilized by the states as they move towards a carbon-free economy.

Northfield is perhaps the most flexible resource located on the New England grid. A pumped storage project, Northfield can start and achieve its full output of 1,168 MW within 10 minutes. Northfield can serve as load or generation during specific hours of the day when it is most needed, ramping that functionality up (or down) within minutes. These characteristics will be extremely valuable in balancing supply and demand on the grid as the New England system moves towards greater integration of renewable resources and faster generation ramp rates are required. In the near-term, however, Northfield's operational attributes can be used to achieve other goals to provide greater value to consumers, namely:

- Reductions in state and system-wide carbon emissions
- Reductions in cost to load tied to peak shaving
- Increased energy security through reduced reliance on natural gas

Unfortunately, Northfield's operations as a merchant facility would prevent it from fully realizing these benefits in ISO-NE day-ahead energy markets. Without fully incorporating the social cost of carbon into dispatch decisions, the carbon reduction capabilities of storage assets such as Northfield will not be fully utilized. Other benefits such as lower energy prices to Massachusetts load and to the broader New England region also will not be fully realized. While ISO-NE Energy Security Improvements ("ESI") design will address compensation for energy security, it will not address the carbon reduction and

[1] In addition to Northfield, insights may apply to the existing Bear Swamp Pumped Storage Generating Station (or Jack Cockwell Station) and large battery facilities proposed to come online by the mid-2020s.

cost to load savings possible from Northfield. Further, over time, changes to the market rules will be required to ensure firm sustainable ramping capability to complement intermittent renewable generation profiles and meet anticipated fast-ramp requirements. For now, Northfield operates on a merchant basis in response to incentives in ISO-NE energy, capacity and reserves markets.

When Northfield participates in the day-ahead energy market, Northfield generation is utilized less than half the time that it otherwise could be. As a result, contributions that Northfield can make to help the states reduce carbon and lower costs to serve load will not be realized.

If Northfield were operated differently, with the objective of reducing carbon emissions or cost to load, Massachusetts state environmental objectives could be realized at a reduced cost for Massachusetts residents. Even a simple contract that requires Northfield to generate a minimum level of output during the equivalent of the five highest-priced hours in the day-ahead energy market realizes significant carbon emissions reductions at a reduced cost to load.

This report summarizes the potential benefits that Northfield can offer to Massachusetts and New England in an increasingly renewable world as a merchant facility and under contract.

- **Section 1** provides a brief overview of Northfield.
- **Section 2** describes an alternative operational scenario under which Northfield is guaranteed to produce a minimum amount of energy each day.
- **Section 3** describes the potential reduction of carbon emissions that Northfield's increased operational output under contract can provide to the region.
- **Section 4** describes the reduced cost to load associated with peak shaving associated with the assumed contract, indicating that both benefits can be realized, making Northfield's carbon emissions reductions a cost-effective approach to realizing New England goals.
- **Section 5** addresses Northfield's impacts on natural gas consumption during winter months if operated under the assumed contract.
- **Section 6** examines costs associated with other storage solutions.
- **Section 7** summarizes results and key findings.
- **Appendices** provide more detail underlying the data sources, methodology and assumptions.

1. OVERVIEW OF NORTHFIELD MOUNTAIN PUMPED STORAGE

Northfield is a pumped storage hydroelectric facility located in Northfield, MA on the Connecticut River system. Originally developed to balance output from a nearby nuclear plant, Northfield now operates as a merchant facility in the ISO-NE markets.

Known as "New England's Largest Battery," Northfield is a 1,168 MW pumped storage facility with four units with nameplate capacity of 292 MW each and a five-billion gallon reservoir, that can generate more than 1.25 TWh per year. Located in the Connecticut River system in Northfield, Massachusetts on the 345kV transmission network within the ISO-NE Western Massachusetts zone. The facility has been a valuable asset to New England's power and transmission system since the early 1970s. Northfield currently is owned by FirstLight Power, Inc. ("FirstLight").[2] FirstLight has operating offices in Northfield, Massachusetts; New Milford, Connecticut; and Burlington, Massachusetts.

Under merchant operation, Northfield pumps water into the reservoir via spot market purchases from the ISO-NE energy market during off-peak hours. Northfield commits to generate electricity during on-peak hours when day-ahead market energy prices are high enough to cover costs of pumping, storage and release. In addition, the facility also bids into the real-time energy market and provides energy on a real-time basis when it is economic to do so. Northfield is an important system resource to ensure reliability, and often uses the water in its reservoir to provide operating reserves in real-time.

As a merchant facility, Northfield operates in response to competitive price signals, providing energy, capacity and operating reserves into ISO-NE markets. Northfield's flexible operations also can provide additional benefits outside of ISO-NE markets. These system-wide social benefits include emissions reductions that can be realized along with a reduction in cost to load associated with contracted peak price shaving. The following additional benefits can be realized when Northfield operates under contract versus merchant operations under projected conditions, in particular:

- **Reduced Carbon Emissions:** Northfield can reduce carbon emissions on a net basis

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[2] In July of 2006, Northeast Utilities agreed to sell its generation assets to Energy Capital Partners; Energy Capital Partners successor company, FirstLight Power Resources, was acquired by GDF SUEZ (now known as ENGIE) in December 2008. On June 1, 2016, FirstLight Power Resources was acquired by PSP Investments and the company now does business as FirstLight Power, Inc. https://www.firstlightpower.com/.

by moving generation from periods of low system demand and less carbon-intensive resources to periods of higher demand to displace higher carbon output resources. This impact can be further optimized compared to its operations as a merchant plant because the ISO-NE markets do not currently incorporate the social cost of carbon into dispatch decisions.

- **Reduced Costs to Load:** Northfield operations can result in a net price reduction to load. Pumping generally occurs during off-peak hours when supply is "flat" and an increase in demand does not have much impact on energy prices. Generation occurs during high-priced periods when the supply curve is "steep" (i.e., price-elasticity of supply is high) and Northfield's operations can have a significant impact on prices by avoiding the use of more expensive peaking units or even more expensive demand response. Under contracted operation, Northfield can play a larger role in reducing costs to load.

- **Increased Energy Security and System Reliability:** Northfield can displace natural gas-fired generation and contribute to enhancing energy security. Northfield also provides critical fast-ramp capability, which will become even more important as renewable resources such as offshore wind and behind-the-meter solar come online.

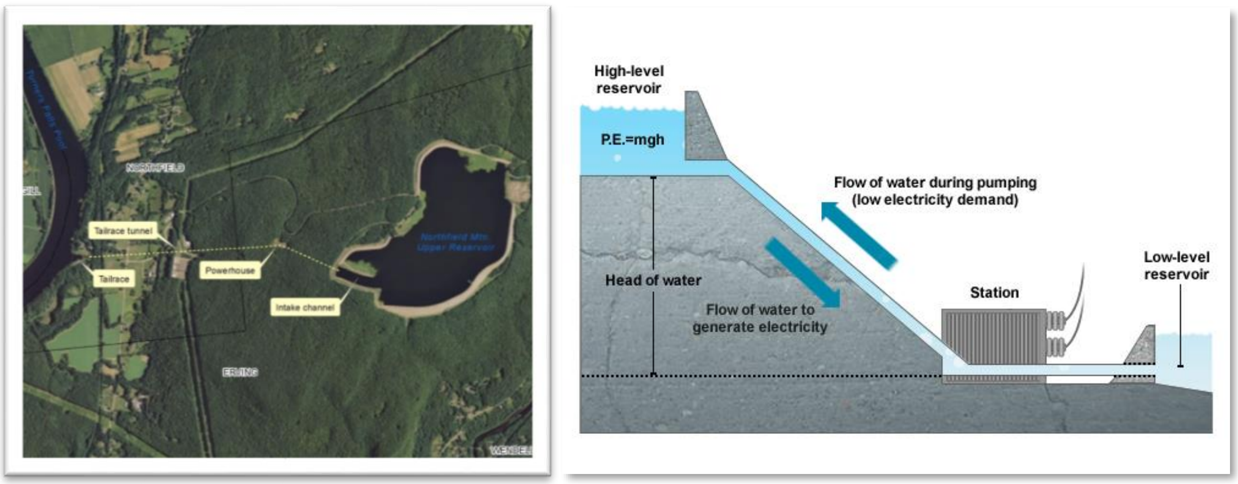
Realization of these values can occur with a simple contract that requires Northfield to deliver a minimum amount of energy each day in the ISO-NE day-ahead energy market.

1.1. Background

In late 1964, Connecticut Light & Power, Hartford Electric Light Company, and Western Massachusetts Electric (all of which are legacy companies of Northeast Utilities and now Eversource), applied for construction of the Northfield project. A final license was issued in August 1968. Northfield became operational in 1972.

As with most pumped storage plants, Northfield includes an upper reservoir, intake channel, powerhouse, and tailrace tunnel, which links the pumped storage facility to the Connecticut River (Figure 1).

Figure 1: Northfield Mountain Pumped Storage Project[3]



Northfield originally was expected to consume excess energy produced by a number of planned nuclear units during evening hours and generate electricity during peak hours when power was needed most. During the 1970s, construction of some of those nuclear units did not come to fruition. During the past twenty years, nuclear units that were built have since retired (e.g., Pilgrim Plant, the Vermont Yankee Nuclear Power Plant). Others still operate, but have threatened to retire (e.g., Millstone). Instead of supporting improved use of nuclear power, Northfield is now positioned to assist with realizing the full potential of any zero or low carbon emissions energy source.

1.2. Operating Characteristics

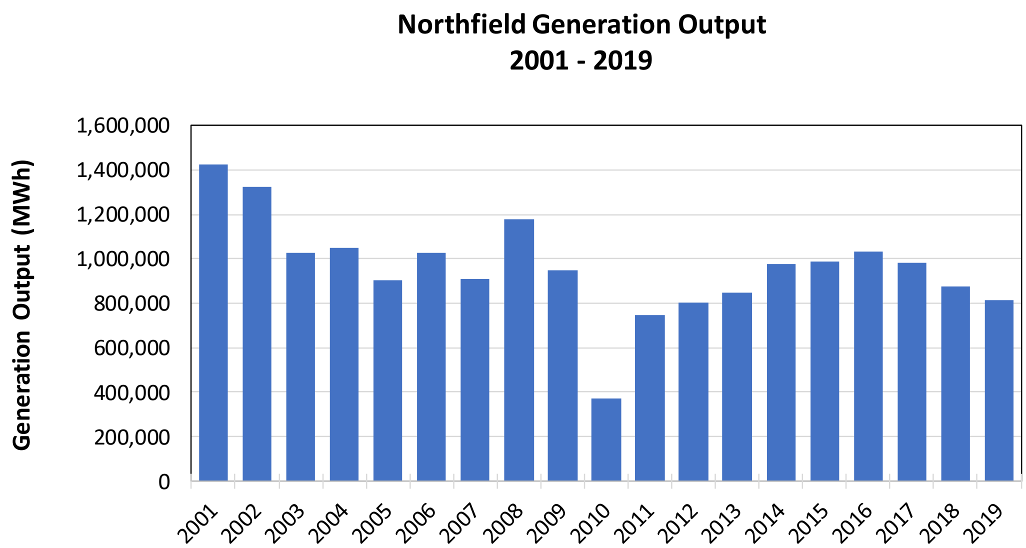
Northfield's powerhouse contains four reversible pump/generating turbines operating at gross heads ranging from 753 to 825 feet. These generators can produce up to 1,168 MW, based on a nameplate capacity for each unit of 292 MW. In pumping mode, each of the four turbines can operate at 250 MW in hourly increments with a minimum operating time of one hour. Since the pumping load is curtailable, pumping operation supplies synchronized operating reserves.

As a merchant facility, Northfield generally is utilized only when market signals indicate that it is economic to operate. This is illustrated in Figure 2, which indicates the historical trend of operations at Northfield. With respect to generation, Northfield rarely operates

[3] FirstLight Power and Energy Systems and Energy Storage Labs, http://energystoragesense.com/wp-content/uploads/2014/06/Pumped_Hydro_schematic.gif

above half of its potential capacity and currently generates well below its twenty-year historical high. In addition, the trend over the past four years indicates that Northfield operations is declining.

Figure 2: Northfield Mountain Annual Output (2001-2019)[4]



As a merchant facility, Northfield only generates electricity during on-peak hours when it is priced high enough to cover costs of pumping, storage and release. Although Northfield has flexibility to optimize pumping and generation over the course of a 7-day projection period, there are times when it is uneconomic for Northfield to operate in ISO-NE markets. As a result, Northfield generated only 0.8 TWh in 2019, a total capacity factor across day-ahead and real-time energy markets (including dispatch of reserves) totaling less than 8 percent.

The decision to pump and generate a merchant pumped storage facility generally is based on the relative price levels of peak versus off-peak prices and the round-trip efficiency factor. As with any battery or electric storage system, Northfield's delivery of off-peak energy to on-peak periods involves losses associated with pumping into the reservoir and subsequent release as generation. Northfield generally has to pump 1.35 MWh to produce 1 MWh of energy. An energy price differential adequate to overcome that ratio is required in order for operations to be economic. Merchant bids to operate pumping or generation

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[4] US EIA, Form 923 data, https://www.eia.gov/electricity/data/eia923/

in the day-ahead energy market also must consider opportunities costs foregone in real-time energy markets.

Trending reductions in Northfield generation can be attributed to lower energy price spreads tied to:

1) Excess generating capacity in ISO-NE;
2) Low natural gas prices;
3) Stagnant net load growth due to energy efficiency; and
4) Increased renewable energy generation.

These four factors generally are anticipated to continue through the mid-2020s, making it likely that Northfield capacity factors will fall even further before volatility introduced by renewable resources and increased load from electric vehicles and heat pumps tightens supply and demand. These trends are confirmed by the analysis and results described in the next section.

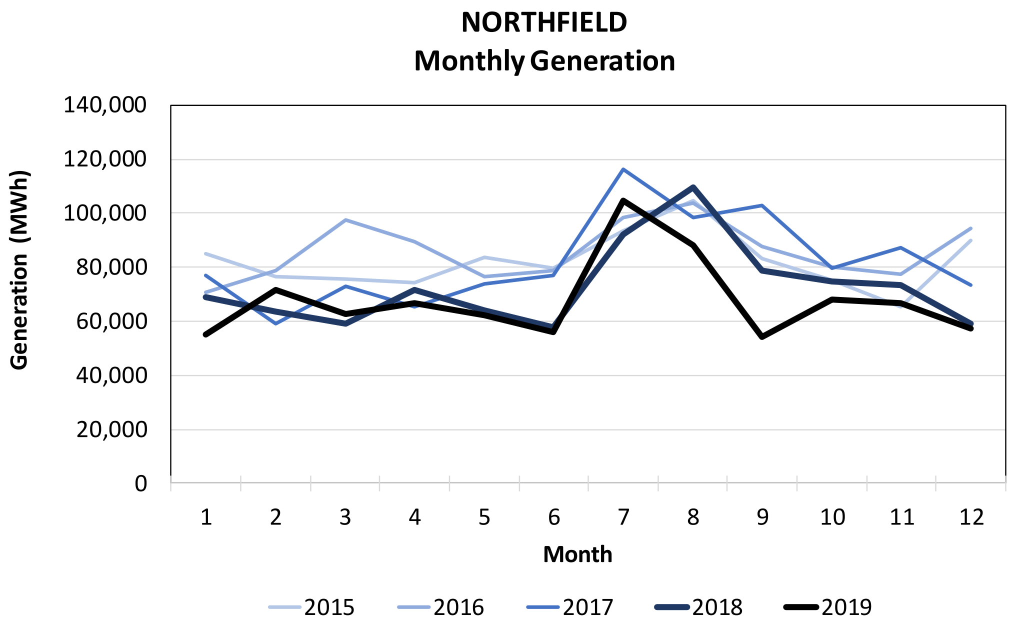
1.3. Traditional Electricity Products

Northfield has sold electricity products under contract as well as into New England's competitive markets for energy, capacity and reserves. Information on each of these revenue streams is provided below.

1.3.1. Energy

During the past five years, Northfield has generated up to 120,000 MWh per month, for a total annual average production of 800,000 to 1 million MWh per year (Figure 3). This reflects a capacity factor of less than 30% of the eight highest peak hours per day during which Northfield conceivably could operate as full load generation.

Figure 3: Monthly Generation at Northfield (2015-2019)[5]



Electricity market design fails to realize Northfield's potential value propositions for three reasons:

1) **The ISO-NE markets have a different objective function:** The objective function for dispatch under the ISO-NE energy and reserve market design minimizes total production costs. This is not the same as minimizing carbon emissions or decreasing costs to load, two of the objectives pursued by the New England states, especially Massachusetts, in their alternative energy procurement decisions. Northfield can assist with both of those state-level objectives, but optimizing against those objectives will not occur with projected merchant operations under ISO-NE market rules and therefore would require a contract that requires greater generation output to realize those goals.

2) **Excess supply and zero marginal cost resources are projected to continue:** Much of the clean energy that will be integrated into the ISO-NE system going forward has a zero or negative marginal cost of production. As more renewables and clean energy resources come online in the current world of low natural gas prices, and traditional fossil fuel generation resources are required to stay online for energy

[5] Energyzt analysis of FERC Form 923 data, https://www.eia.gov/electricity/data/eia923/

security, market equilibrium will continue to clear at the "flat" part of the supply curve, limiting the price differentials required by Northfield to operate. As a result, Northfield's operating capacity factor can be expected to decline over the next few years, despite the need for cost-effective carbon emissions reductions and the benefit of reduced cost to load that Northfield offers.

3) **Variable renewable generation output:** Increased integration of renewable energy results in greater shifts of the supply curve on a daily and hourly basis, resulting in dynamic supply conditions that change from day to day. This volatility is likely to have more impact on a real-time basis, driving Northfield energy sales to in real-time markets instead of day-ahead energy markets. Response to real-time price signals, however, will offer Northfield increasingly volatile and uncertain revenue streams, and would not be guaranteed to optimize carbon emissions reductions nor achieve the reductions in cost to load in day-ahead energy markets that are possible.

A contract for guaranteed dispatch can overcome these market limitations.

1.3.2. Capacity

For a number of years, Northfield has successfully bid capacity into ISO-NE forward capacity markets ("FCM"). Northfield currently has capacity supply obligations for 292 MW for each of the four units, with a plant total of 1,168 MW through May 2024.[6]

1.3.3. Operating Reserves

Northfield has quick-start capability and can start and generate up to maximum capacity within 10 minutes. This fast ramping time generally is valued as off-line fast start operating reserve in ISO-NE real-time reserve markets. Twice each year, Northfield offers its reserves into the ISO-NE forward reserves market and the real-time operating reserve market. Whether used for activation in response to a contingency or other system scarcity situations, this fast start response can be valuable when the facility is called upon to deliver.[7]

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[6] ISO-NE, 2020-2021 CCP Forward Capacity Auction Obligations, 3/1/2017.

[7] Going forward, reserve requirements are proposed to be incorporated into day-ahead markets under ESI. Northfield is likely to be committed to provide reserves given its quick-start, fast-ramp capabilities and sizeable capacity blocks.

1.4. New Value Propositions

Renewable generating resources developed to reduce carbon emissions are commanding support via long-term contracts and clean energy premiums available through market-based programs such as renewable energy credits and the Regional Greenhouse Gas Initiative. Following the extreme winter conditions of 2012/13, 2013/14, and 2014/15, and growing concern with fuel security in the region, some states are placing a premium on fuel diversity and a generator's ability to perform in the face of potentially constrained natural gas delivery. ISO-NE is engaged in an initiative to compensate for energy security. Price reductions effectuated by renewable resources have been used, in part, to justify continued support at the state level.

Northfield offers similar value propositions to these resources at competitive price levels. The following section describes a potential contractual structure that could allow Northfield to operate more frequently while decreasing carbon emissions and cost to load, contributing to energy security through displacement of natural gas-fired generating resources, and maintaining an ability to provide ramping capability and reserves outside of the contracted dispatch.

2. NORTHFIELD OPERATIONS

Excess generation supply on the system and record low natural gas prices combine to challenge Northfield merchant generation under recent and projected market conditions. An alternative arrangement could serve to increase Northfield's output in day-ahead markets, realizing carbon emissions reductions as well as reductions in cost to load.

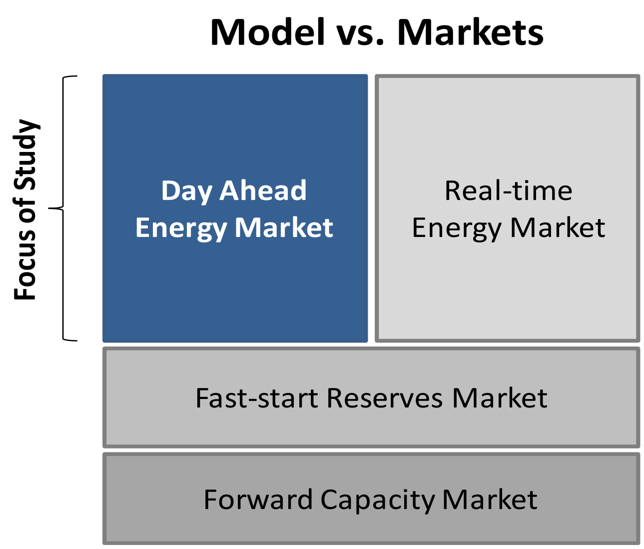
The analysis uses PLEXOS, a production cost model, to quantify potential benefits of an alternative contractual arrangement that would increase Northfield dispatch on a daily basis. This section describes the core underpinnings of the analysis, including which markets were analyzed, the base case and the alternative case. Results are reported in Sections 3 through 5. Appendix C provides additional detail on the underlying assumptions.

2.1. Market Analyzed

For purposes of assessing the potential benefits of Northfield, Energyzt focused on ISO-NE day-ahead energy market. As already noted, Northfield supplies a number of different electricity products to ISO-NE. The bulk of generation and load is cleared in the day-ahead energy markets, with all generators holding a capacity supply obligation required to offer into the day-ahead and real-time energy markets. As of mid-2019, most renewables with capacity commitments were required to bid into the ISO-NE day-ahead energy markets.[8] Long-term contracts also generally require generation to schedule in day-ahead markets.

Therefore, in order to create a proper comparison of Northfield's impacts operating as a merchant versus contracted facility, the analysis focuses on modeling the day-ahead energy market and the impact of Northfield's operations in that market, illustrated in Figure 4.

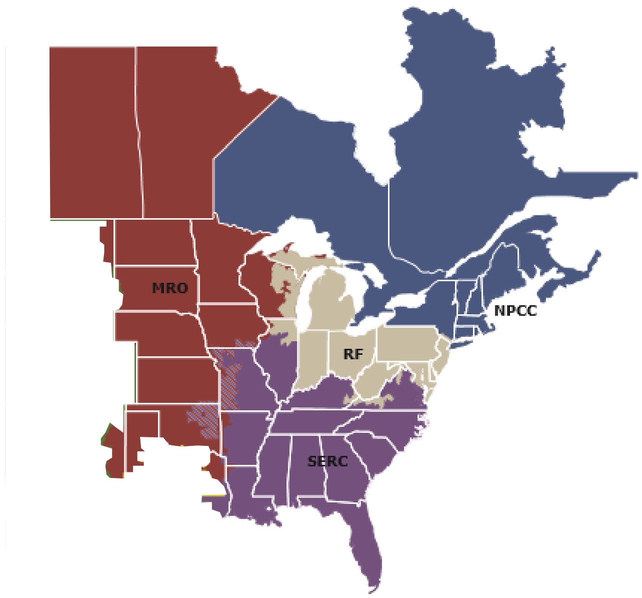
Figure 4: Illustration of Market Impact Being Analyzed



ISO-NE is interconnected to the broader Eastern Interconnect as well as Québec and New Brunswick. The model includes these interconnections as well as a complete representation of the interconnected markets with specific generation facilities, zones and load projections (Figure 5).

[8] Utility Dive, https://www.wind-watch.org/news/2019/06/09/iso-ne-will-require-wind-intermittent-hydro-to-bid-into-day-ahead-energy-markets/

Figure 5: Scope of the Market Model



Modeled Interconnections with ISO-NE

New York

- Western Massachusetts – New York
- Connecticut – Long Island
- Connecticut – New York
- Vermont – New York

Québec

- Phase II
- Highgate
- NECEC

New Brunswick

- Maine

2.2. Base Case: Northfield Operations as a Merchant Plant

The base case assumes that Northfield would continue to operate as a merchant plant in ISO-NE markets.[9] In the model, Northfield's merchant operations are dispatched based on a day-ahead type optimization schedule that and assumes all units can be used for pumping or generation to realize the maximum spread between generation revenues and pumping costs based on a single reservoir. Each unit has the same underlying variable costs of production, but distinctions between bids for each unit reflects Northfield's real-time energy market opportunity cost impacts of day-ahead scheduling.[10]

In addition to the assumed bids, the model specifies a number of other Northfield operating parameters, including:

[9] Excess generation supply on the system and record low natural gas prices create price suppression that prevents Northfield from operating under existing ISO-NE dispatch algorithms.

[10] Energyzt worked with FirstLight to understand the basis for its bidding strategy as a merchant plant and how that would change under contract. Energyzt then incorporated this strategy into bid adders for each case that reflect both variable O&M costs as well as FirstLight's bidding strategy.

- Number of units: 4 units
- Unit output:
  - Minimum unit output = Provided by FirstLight
  - Maximum unit output = 292 MW per hour
- Pumping: 250 MW in hourly increments
- Round-trip efficiency: 1.35 MWh pumping for every 1 MWh generation
- Reservoir modeled as a single reservoir shared by all units with a maximum capacity of 8,750 MWh

Based on these operating assumptions and the market representation, market model projections indicate that Northfield's downward trend in capacity factors will continue through 2023. As low natural gas prices are projected to continue and certain fossil fuel resources are retained for energy security, ISO-NE's day-ahead market is projected to provide reduced economics for dispatch of electric storage such as Northfield, resulting in lower capacity factors. By 2023, Northfield is projected to be dispatched in day-ahead energy markets with only a 1.5 percent capacity factor.[11]

After 2023, Northfield's dispatch in day-ahead energy markets increases only as more renewables come online and higher volatility is introduced into the market as a result of rising natural gas prices, unit retirements (e.g., Mystic in June 2024) and load growth due to heat pumps and electric vehicles. These factors all serve to tighten the market and increase the spread between peak and off-peak prices in certain hours, thereby encouraging greater Northfield dispatch in the day-ahead energy market as a merchant plant. By 2030, Northfield's participation in day-ahead energy markets is projected to reach a capacity factor of 5 percent (Figure 6) compared to a total potential capacity factor of around 30 percent if the plant were fully utilized every day.

[11] This usage does not include designation as reserves. Northfield bids its units into the ISO-NE market and is available for dispatch in both the day-ahead and real-time markets as required to meet reliability needs.

Figure 6: Northfield Projected Day-Ahead Energy Merchant Capacity Factors

Scenario	Merchant
2022	1.7%
2023	1.5%
2024	2.2%
2025	3.0%
2026	3.4%
2027	4.9%
2028	4.7%
2029	5.3%
2030	5.0%

It is important to note that these capacity factors represent Northfield's dispatch for purposes of energy in ISO-NE's day-ahead energy markets only. Historically, Northfield has experienced higher total capacity factors which combine generation in ISO-NE's day-ahead energy market and the real-time energy market.[12] This analysis focuses on ISO-NE day-ahead markets because that market is where energy under a contract would be bid and most of New England load is priced at either contract rates or day-ahead market prices.

2.3. Contracted Case: Northfield 1 & 2 Dispatch at Least 5 Hours Each Day

The alternative case assumes that Northfield Units 1 and 2 operate under a contract, and Units 3 and 4 would continue to operate on a merchant basis. The assumed contract structure would require Northfield to generate, at a minimum, the equivalent of five hours of output each day during the highest-priced hours. This equates to a minimum generation under contract of 2,920 MWh (i.e. 292 MW x 2 units x 5 hours) split evenly between Units 1 and 2 (i.e., 1,460 MWh per unit per day). The contract is assumed to allow Northfield the ability to manage its units to pump water into the reservoir to meet this obligation, allowing for optimized pumping across all four units, as currently occurs.[13] The goal of the energy storage contract is to move renewable energy from off-peak hours to higher-priced peak hours.

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[12] See for example EIA Form 923 data which includes all generation output of the Northfield units.

[13] This arrangement is different than a tolling agreement which would assign pumping and generation at a single unit to the contractual counterparty. As such, the contract will need to include details concerning how revenues and costs of dispatch are allocated to the contracted unit dispatch in the agreement.

Dispatching a minimum amount of Northfield generation to meet the highest-priced hours is performed dynamically through the market model optimization program. In the past, the highest-priced hours were relatively easy to anticipate based on historical load patterns. Going forward, however, increased renewable integration will change the peak pricing hours to be more variable. As wind and solar vary from hour to hour, the periods with highest prices will vary from day to day based on total load and a dynamic supply curve. Those hours will not always follow the same pattern as historical patterns (see a more detailed explanation in Section 5.2). Under the contract case, Northfield is optimized by the model's dispatch algorithm to operate the two units during the highest-priced hours in each day, whenever those hours occur, so long as each unit produces a minimum of 1,460 MWh per day.

It is important to note that a contract counterparty may have the flexibility to optimize Northfield against any criteria it wishes. For purposes of this analysis, however, Northfield operations are optimized for Units 1 and 2 against the highest hourly prices for energy with pumping optimized across all four units. As this approach does not optimize the impact on carbon emissions, price reductions, or natural gas displacement, the calculation of these other system-wide price impacts should be viewed as understating what could be achieved if a different optimization rule were in place with access to relevant information to realize the alternative objective.

The contract case also allows for additional dispatch of Units 1 and 2 outside of contracted operations. There may be days when it is economic to dispatch Northfield outside of the highest-priced hours when contracted dispatch would occur. To the extent market conditions support additional merchant dispatch by Northfield Units 1 and 2 outside of the contracted generation, the model is allowed to dispatch those units economically. As a result, the capacity factor associated with Units 1 and 2 can be above 20.8 percent implied by a 5-hour equivalent dispatch each day.

of the ability to dispatch economically outside of the five highest-priced hours.
Figure 7 compares the net result of the assumed contractual structure on capacity utilization in the day-ahead energy market as compared to the merchant case for each unit. Under the contract case, Units 1 and 2 operate at around a 22 percent capacity factor. This is slightly higher than the equivalent of 5 hours per day out of 24 hours total because of the ability to dispatch economically outside of the five highest-priced hours.

Figure 7: Northfield Projected Day-Ahead Market Capacity Factors by Unit[14]

	Unit 1		Unit 2		Unit 3		Unit 4	
Year	Merchant	Contract	Merchant	Contract	Merchant	Contract	Merchant	Contract
2022	5.0%	21.6%	1.1%	21.5%	0.4%	0.9%	0.2%	0.3%
2023	4.8%	21.6%	0.9%	21.6%	0.3%	0.9%	0.2%	0.2%
2024	6.3%	21.6%	2.0%	21.5%	0.4%	1.6%	0.2%	0.3%
2025	7.9%	21.7%	3.2%	21.5%	0.6%	2.1%	0.2%	0.3%
2026	8.7%	21.8%	3.6%	21.7%	0.9%	2.5%	0.3%	0.5%
2027	9.7%	21.9%	4.3%	21.9%	1.2%	3.1%	0.5%	0.6%
2028	10.9%	22.1%	5.1%	21.8%	2.0%	3.9%	0.9%	1.1%
2029	11.4%	22.2%	6.1%	22.1%	2.5%	4.4%	1.3%	1.5%
2030	10.8%	22.3%	5.6%	22.1%	2.3%	4.4%	1.2%	1.5%

2.4. Other Assumptions

Numerous assumptions are required to model and run the Eastern Interconnect model. The appendices describe underlying data, methodology and key assumptions associated with the analysis.

3. CARBON EMISSIONS REDUCTION

Northfield is both a generator and dispatchable load. As a result, operations include times when system-wide carbon emissions are reduced (e.g., during peak hours when Northfield generates) as well as times when system-wide carbon emissions could be increased (e.g., during pumping hours). Conceptually, the incremental impact of a megawatt-hour of generation on carbon displacement during peak hours should be higher than the incremental impact of a megawatt-hour of pumping during most off-peak hours when zero or low emission (i.e., more efficient) units are on the margin. This has been true in the past when ISO-NE operated primarily with fossil fuels. This also will be true as increased renewable integration occurs and low carbon-emitting resources are on the margin more frequently during low-priced hours.

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[14] Capacity factors under the merchant scenario and contract scenario reflect Northfield operations under confidential bids provided to Energyzt by FirstLight.

ISO-NE also has another dynamic related to imports. The New England power system has direct interties with New York, Québec and New Brunswick. As a result of excess energy in those systems, ISO-NE has benefitted from energy imports. In 2019, net flows over external interties was 19 percent of the ISO-NE generation mix, with Québec imports alone supplying 12 percent of ISO-NE load.[15] These imports take advantage of New England's winter and summer peak prices, shifting energy from low-cost areas of the Eastern Interconnect into higher-priced New England electricity markets. Under projected market conditions, they can replace the renewable energy moved by Northfield from periods of low demand to periods of higher demand. Northfield also can displace those imports during certain generating hours, reducing carbon emissions in other markets, resulting in a net reduction in carbon emissions system-wide.

That said, all electric storage transportation of energy across hours involves storage and conversion losses. Northfield's efficiency factor requires more megawatt-hours of energy input (pumping) than is delivered as output (generation). There also could be times, albeit rarely, when coal or oil could be used to replace renewable energy moved by Northfield pumping, leading to a slight increase in carbon content in such hours (e.g., more than 206 lbs per mmBtu for coal versus natural gas emissions of 117 lbs per mmBtu).[16] The combination of efficiency factors, changing marginal carbon emissions rates, and operating decision rules requires more detailed analyses to determine the extent of net carbon reductions that Northfield can offer to New England and neighboring regions.

Figure 8 illustrates when Northfield can reduce carbon emissions on a net basis. If off-peak hours occur when imports or units with low carbon emissions on are the margin to replace the renewable generation moved by Northfield, the periods when storage is charging has little impact on carbon emissions and can create a net decline in carbon emissions when generation shaves peak demand supplied by higher emission resources.

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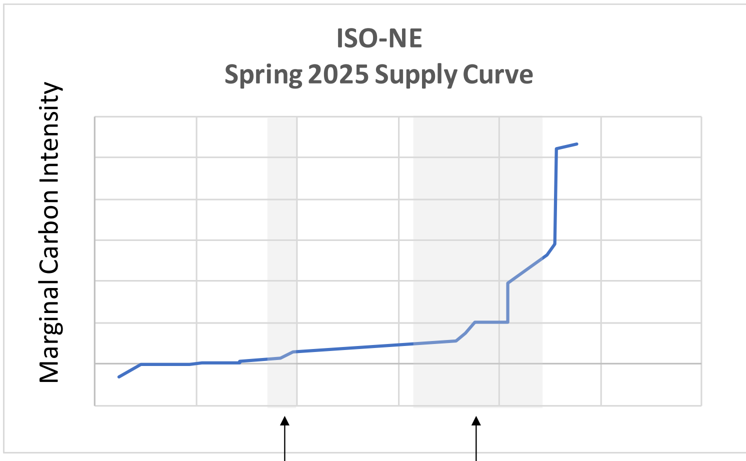
[15] ISO-NE, https://iso-ne.com/about/key-stats/resource-mix

[16] EIA, https://www.eia.gov/tools/faqs/faq.php?id=73&t=11

Figure 8: Northfield Illustration of Conditions When Carbon Emissions are Reduced

Steep Supply Curve = Northfield Contract Price Reductions



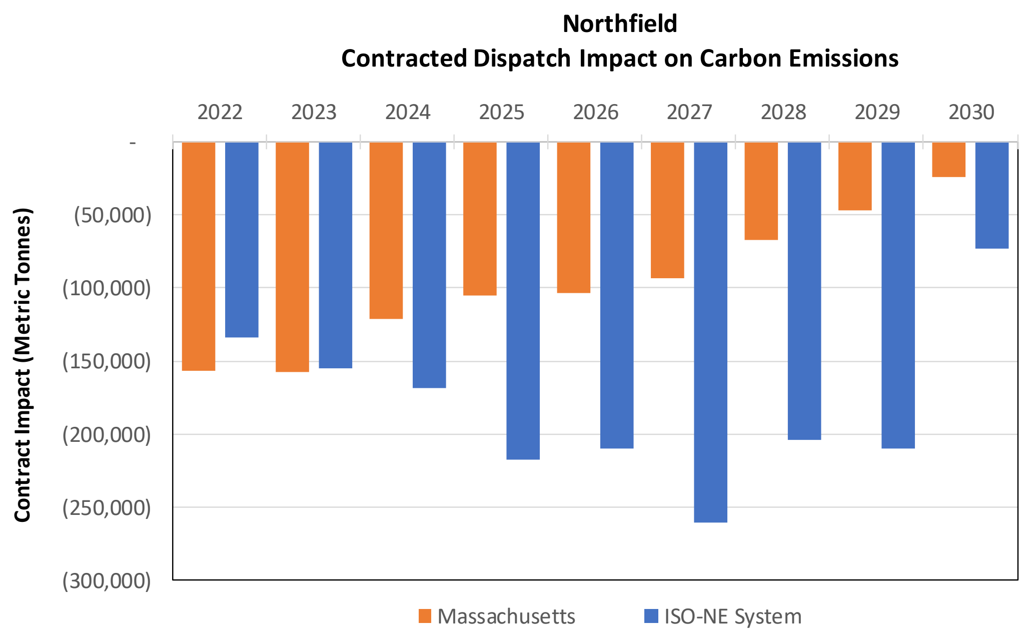
Northfield Can Reduce Carbon Emissions
On a Net Basis

As additional renewable resources continue to come online, energy to replace the renewable energy moved by Northfield pumping increasingly will be cleaner energy. Volatility in renewable output also creates opportunities for Northfield to offset the emissions impact by generating when renewables are generating less energy and fossil fuels are on the margin.

During peak periods such as summer and winter, Northfield can create carbon emissions benefits because the market is more likely to operate at the less efficient, higher carbon-emitting fossil-fuel part of the supply curve during high-priced hours. If the market is operating on the "flat" part of the supply curve for both off-peak and on-peak hours, it could be more difficult for Northfield to reduce emissions depending on the nature of energy supply that will replace the renewable energy Northfield pumping moves to higher demand periods.

These dynamics require an hour-by-hour analysis of the market. In order to estimate the impact of Northfield's contractual operations on system-wide carbon emissions, Energyzt compared total carbon emissions for Massachusetts, New England, and the entire Eastern Interconnect under the base case versus the contract case. In all years, a contract with Northfield results in a net reduction in carbon emissions (Figure 9).

Figure 9: Northfield Contract Impact on Carbon Emissions (Metric Tonnes)



Region	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Massachusetts	(156,289)	(157,268)	(121,496)	(105,489)	(103,839)	(93,709)	(66,954)	(46,590)	(24,295)	(875,929)
ISO-NE	(134,003)	(155,334)	(168,653)	(217,548)	(210,164)	(260,554)	(204,362)	(209,583)	(72,905)	(1,633,105)

The pattern of carbon emissions reductions provides additional insights.

Massachusetts places the highest carbon emissions price on its generators and has some of the most aggressive renewables targets. By 2030, Massachusetts in-state renewables is projected to serve a larger portion of Massachusetts consumers' demand, with the remainder supplied by the broader New England market. Northfield contracted service would increasingly displace fossil-fuel units in other New England states, helping the entire region to meet its carbon reduction goals by 2030. As Massachusetts and the region moves towards achieving their carbon emission reduction goals, Northfield can play a key role.

Northfield also reduces carbon emissions outside of New England as a result of the contract displacing imports from connected markets. For example, Northfield displaces more than 550,000 metric tonnes across the entire Eastern Interconnect in 2026 and 2027 before other markets are projected to start to add new generation to achieve their own renewable goals and maintain adequate reserve margins.

As described further in the next section, these carbon emissions reductions would be achieved with reduced cost to Massachusetts load through 2030.

4. REDUCTION IN COST TO LOAD

Northfield operations impact system-wide prices by:[17]

1) **Unit Commitment:** Displacing higher carbon emitting fossil fuel peaking resources in the unit commitment logic, decreasing prices and emissions;

2) **Increasing Supply:** Increasing supply during generating hours, thereby decreasing prices; and

3) **Increasing Load:** Moving renewable generation via Northfield pumping requires replacement energy to meet demand during pumping hours, potentially increasing prices.

The net impact depends on the relative slope of the supply curve during peak versus off-peak hours and the change in price that occurs when Northfield is available and operating. The steeper the curve during generation hours compared to pumping periods, the more likely the price reduction effect will overwhelm any cost of losses tied to Northfield's roundtrip efficiency rate. As a result, the combination of energy supply and demand, including where the market is clearing on the supply curve, plays a determinative role in the amount by which Northfield can reduce cost to load.

Over the past few years, the projected shape of ISO-NE's supply curve and equilibrium has evolved. In 2015, NERC projected that ISO-NE could be tight on supply, barely achieving its reserve requirements unless new generation came online.[18] Since then, new gas-fired generation has come online, renewables have proliferated in response to policy

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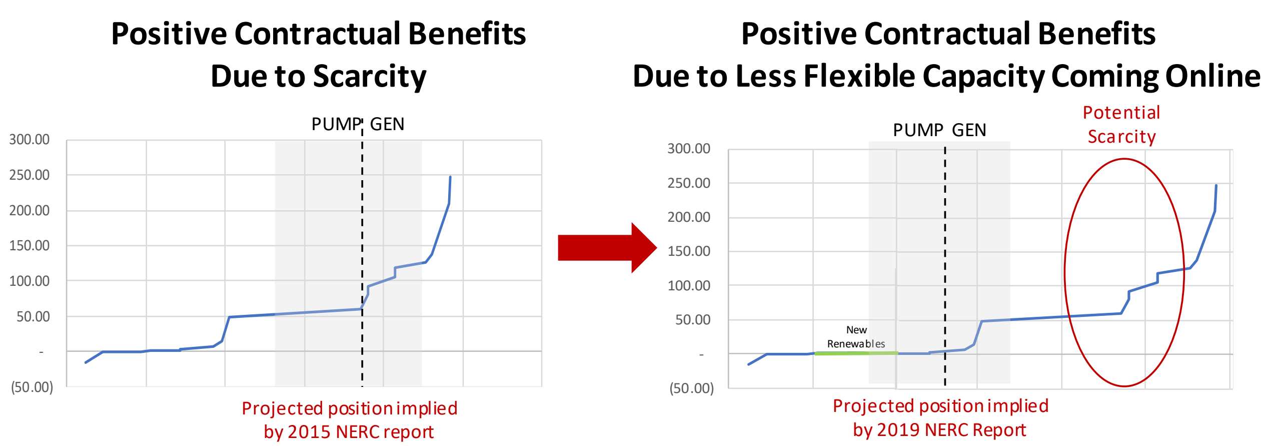
[17] For purposes of this section, impacts on natural gas demand are ignored. Under normal conditions, when the natural gas supply curve does not reflect scarcity conditions, the relative impact of reduced demand for natural gas from the power generation sector would be small.

[18] NERC, 2015 Long-term Reliability Assessment, https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015LTRA%20-%20Final%20Report.pdf

objectives and projected demand has declined, resulting in 2019 NERC projections of excess supply.[19] As ISO-NE moves towards greater renewable integration, the supply curve increasing "shifts out" and equilibrium occurs on lower-priced parts of the curve.

This evolution impacts Northfield's projected ability to decrease cost to load under contract. When ISO-NE was at long-term equilibrium, Northfield could pump using at the flat part of the supply curve and generate at the steeper part of the supply curve, displacing much more expensive units, resulting in significant reductions in cost to load. This still is projected to occur between 2022 to 2030, but for different reasons. Although there are still times of scarcity during peak periods when Northfield can create a significant reduction in cost to load, Northfield also can create value on a daily basis by pumping when renewable resources are producing and can be replaced by imports or low emissions resources that are on the margin with minimal impact on energy prices. Northfield can then use that energy to displace inefficient and costly fossil fuel units when load is high and/or renewable resources are not available (Figure 10).

Figure 10: ISO-NE's Evolving Equilibrium and Northfield's Impact on Cost to Load



In general, Northfield can create a net reduction in energy prices and therefore cost to load under contracted operations. When Northfield generates, it increases supply in the New England system and decreases peak prices. The price reductions are offset during off-peak hours when system load is lower and the market is operating on a part of the supply curve where similarly-priced resources can replace the renewables that Northfield

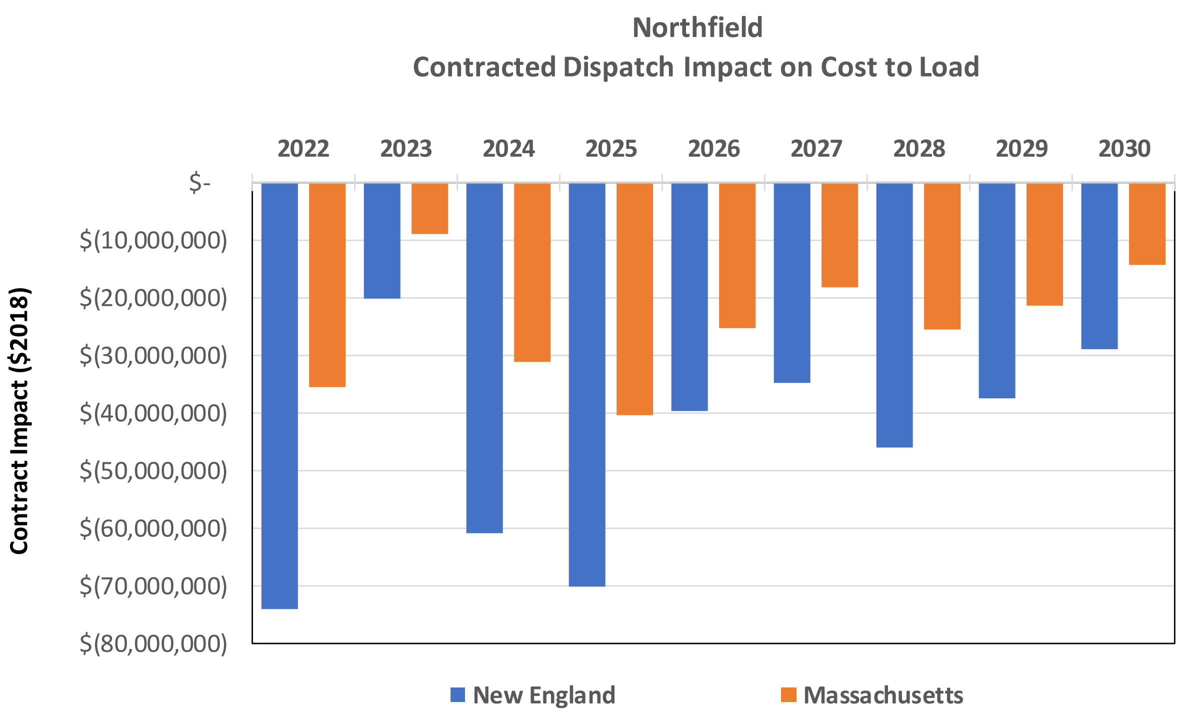
[19] NERC, 2019 Long-term Reliability Assessment,
https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf

is consuming. The smaller increase in price multiplied by the lower load is an offset to Northfield's peak shaving benefits. However, the benefits of Northfield's peak shaving can more than offset the impact on prices when the plant is pumping.

As renewable resources increasingly integrate into the ISO-NE system, the supply curve will become more dynamic, changing from day to day as the availability of renewable resources changes. As offshore wind is particularly strong during the winter months, and solar generates more energy during the summer months, Northfield's impact also can vary from month to month and season to season. Although shoulder months experience less of an impact because of lower demand and less price differentials between peak and off-peak hours, Northfield still can provide value by moving renewable energy from off-peak hours when renewables and imports are on the margin to higher demand hours where that delivered energy can displace more expensive fossil fuel units.

In order to assess the impact of contracted Northfield operations, the model was rerun to reflect a minimum amount of generation output from Units 1 and 2 each day. Energyzt compared the base case to the contract case described in section 2.3 using the same production cost model, market representation and contract dispatch as was used to assess Northfield's impact on carbon emissions. In all years, a contract with Northfield results in a net reduction in cost to load for New England as well as for the Commonwealth of Massachusetts (Figure 11).

Figure 11: Northfield Contract Impact on Cost to Load



Region	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
Massachusetts										
Price Impact (2018 $/MWh)	(0.60)	(0.15)	(0.53)	(0.67)	(0.41)	(0.29)	(0.41)	(0.33)	(0.22)	(0.40)
Cost to Load ($2018 million)	(35.4)	(9.0)	(31.2)	(40.4)	(25.2)	(18.1)	(25.6)	(21.4)	(14.3)	(220.6)
ISO-NE										
Price Impact (2018 $/MWh)	(0.58)	(0.16)	(0.47)	(0.53)	(0.30)	(0.25)	(0.33)	(0.26)	(0.20)	(0.34)
Cost to Load ($2018 million)	(74.0)	(20.2)	(60.8)	(70.2)	(39.7)	(34.8)	(46.1)	(37.6)	(28.9)	(412.3)

(parentheses) indicate cost savings

The higher impact on Massachusetts prices compared to New England is intuitive. Northfield is located in Western Massachusetts and is most likely to impact its own zone directly. Given the interconnected nature of ISO-NE, however, Northfield also can impact surrounding areas including Boston, Southeast Massachusetts and Connecticut as well as the rest of New England. As more renewable resources enter into the market, the supply curve shifts and Northfield's impact could be smaller. On the other hand, variability associated with renewable resources and Northfield's ability to start and stop with minimal lead time increases the opportunity for Northfield to offset price spikes created by a sudden drop off in solar or wind production.

5. ENERGY SECURITY

Northfield contributes to system-wide energy security in two ways:

1) **Displacement of Natural Gas-fired Generation:** Northfield can decrease demand for natural gas during potential times of natural gas scarcity, reducing demand for natural gas and reducing peak gas and energy prices.

2) **Ramping Capability:** As an increasing amount of renewables come online, New England will face greater ramping requirements associated with intra-hour and inter-hour changes in renewable resource availability.

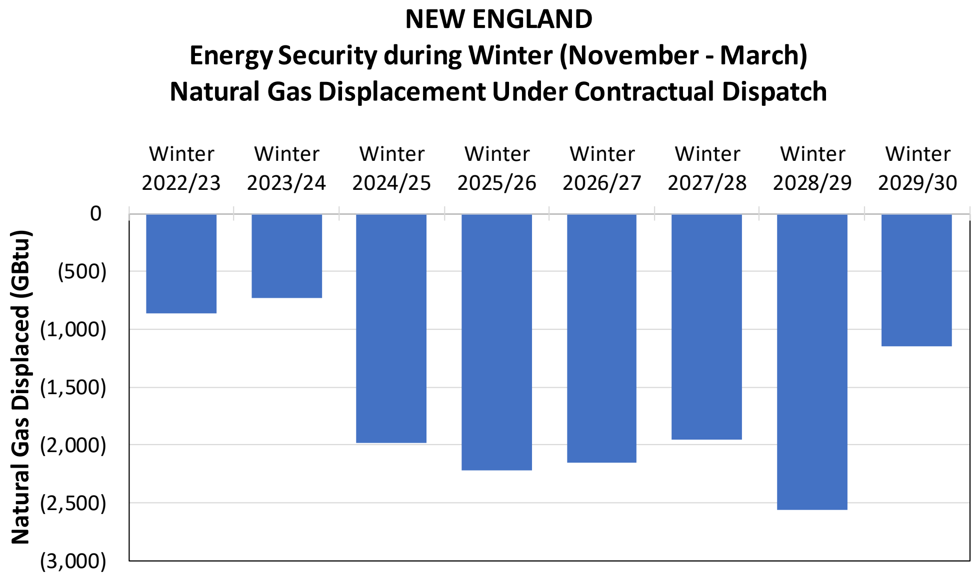
This section uses the results of the market model runs and inputs to illustrate the contribution to energy security and reliability that a Northfield contract offers.

5.1. Northfield Conserves Natural Gas in the Power Sector

Northfield can contribute to more effective use of New England's fuel resources by shifting renewable energy production from hours with more efficient generation replacement to displace less efficient generators. By displacing less efficient natural gas-fired units with generation and pumping during off-peak hours when more efficient or non-gas fired generation would replace the renewable generation Northfield shifts to peak hours, Northfield could further reduce net demand for natural gas and decrease energy prices with peak shaving under contract.

In addition to reducing carbon emissions and costs to load, described in the prior sections, Northfield operations has the additional benefit of reducing New England's reliance on natural gas for electricity generation. Figure 12 illustrates the potential displacement of natural gas that the assumed contract structure could realize during normal winter conditions. The model runs indicate that a Northfield contract could displace roughly 1,500 GBtu of natural gas between the months of November and March each year.

Figure 12: Northfield Impact on Demand from Gas-fired Generators During Winter



GBTu (Nov – Mar)	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
ISO-NE	(863)	(728)	(1,985)	(2,223)	(2,149)	(1,950)	(2,561)	(1,149)

The potential natural gas displacement by Northfield under a potential contract is around 0.5% to 2% of the amount of natural gas consumed by the electricity sector over the past few years.[20] As renewables increasingly integrate into the ISO-NE system, especially off-shore wind which generates more in the winter, the total amount of natural gas estimated to be consumed by the ISO-NE electric sector is projected to decline through 2030. Given regional declines in natural gas consumption for generation, Northfield could displace around 4.1% of electric demand for natural gas by Winter 2028/2029.

Northfield's potential impact on natural gas consumption by gas-fired generators reflects a number of competing factors:

- **Increasing Integration of Renewables:** As offshore wind and other renewables come online, ISO-NE's winter generation fuel mix will require less natural gas.
- **Competitive Oil Prices:** Projected oil prices are lower than natural gas during the winter months, which would displace natural gas-fired generation in dual-fuel

[20] Total natural gas consumption by the electricity sector in New England has ranged from 115,000 to 132,000 over the past five years. EIA, https://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm

units.

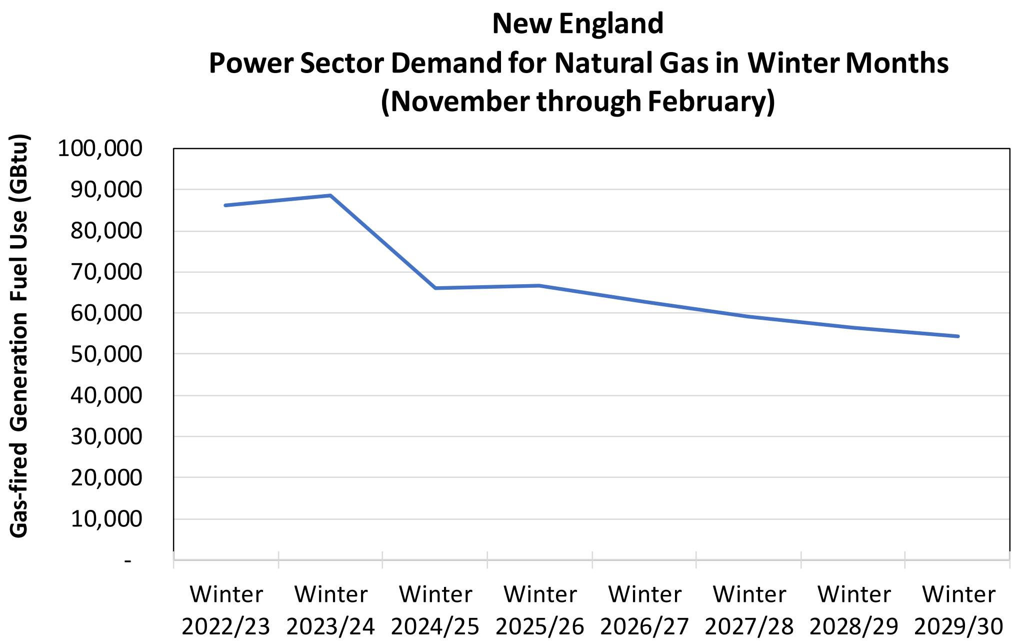
- **Increasing winter demand:** As New England state policy moves towards electric heat pumps, end-user demand for natural gas could decrease while winter demand for electricity would increase, potentially shifting the ISO-NE system to higher natural gas usage.

- **Imports:** The impact of imports on natural gas usage is mixed.
    - New York is building offshore wind to meet its own carbon reduction goals which should decrease the use of natural gas, but is encouraging electric heat pumps which would increase winter load and demand for natural gas-fired generation.
    - Hydro-Québec is completing a build-out of hydroelectric facilities (Romaine-4) and has 500 MW of upgrades planned for 2025, potentially pushing additional imports into New England during the high-priced winter months; on the other hand Québec's winter peak load is projected to grow, which could reduce the amount of imported energy into New England.

When all of these factors are considered, New England's overall reliance on natural gas for winter energy generation is projected to decline over time (Figure 13). Between Winter 2022/23 and 2029/30, renewables and other factors reduce natural gas usage for electric generation during winter months by more than one-third.

ISO-NE is developing an Energy Security Improvements compensation mechanism to incentivize generators to arrange fuel supplies needed to assure reliability. State policies promoting energy efficiency and conversion to heat pumps also could decrease reliance on natural gas going forward. On the other hand, natural gas companies could respond to lower utilization of pipeline capacity by connecting more customers. Regardless, a contract with Northfield could contribute to the ISO-NE system's fuel security concerns going forward by reducing reliance on natural gas even further.

Figure 13: ISO-NE Generator Demand for Natural Gas during Winter Months



5.2. Northfield Provides Fast-Ramp Capability

As more renewables come online, New England increasingly will face another energy security challenge. Markets with heavy integration of solar have recognized what is called a "duck curve" – the change in net load shape that occurs with increased solar integration. As more solar comes online, there is a reduction to load such that the ISO-NE will need to manage ramping capability to cover periods when both load and solar are increasing or declining at the same time. The coincident change in load and renewable generation can create steep ramping requirements where fast-start and quick-ramp capabilities are required to maintain system reliability.

ISO-NE already recognizes the impacts of the duck curve on the system; in spring 2018, solar output reached an estimated record high and drove down electricity demand on the regional power system by 2,300 MW.[21] Solar energy generation patterns also create another challenge for system operators – the decline in solar output combined with increasing load for the evening peak resulted in a 2,000 MW ramp requirement over a three-hour period. Going forward, and as solar installations increase, ISO-NE will need to

[21] ISO-NE, https://www.iso-ne.com/about/what-we-do/in-depth/solar-power-in-new-england-locations-and-impact

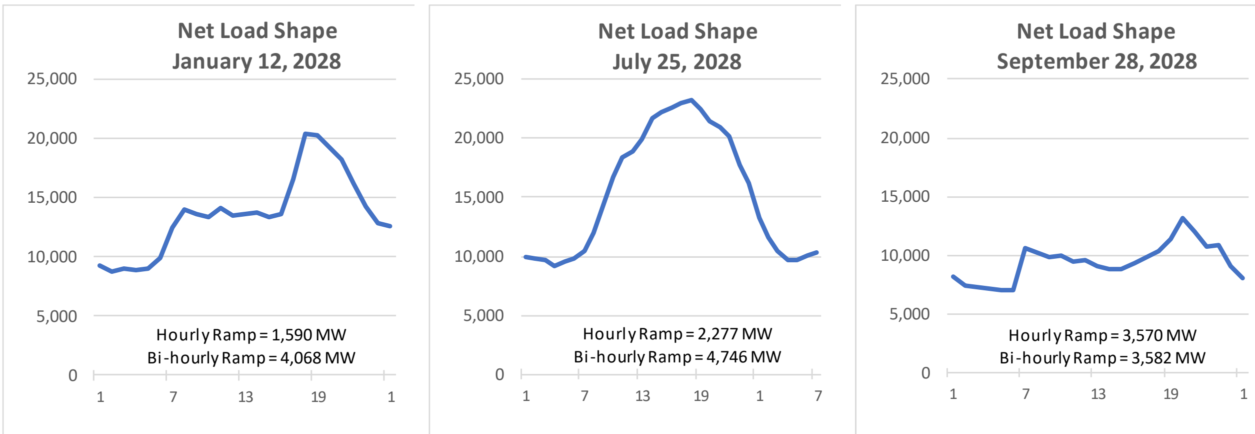
have adequate ramping capability to meet the most extreme ramping rates that can occur within an hour and beyond. Ramping requirements associated with the solar "duck curve" is well understood and fairly straightforward to plan for based on a fairly narrow timeframe when hours of sunlight, cloud cover, and changes in load coincide.

That said, New England faces another ramping challenge that is even more uncertain and volatile tied to offshore wind combined with solar patterns – call it the "shark curve." The term "shark curve" has been applied to a number of factors impacting the traditional load shape including the sometimes missing evening load in developing countries that cannot be serviced[22] and the anticipated fin-like shape of residential load ramp when commuters return home and plug in their electric vehicles.[23] The terminology is adopted here with respect to the impact of offshore wind so as to limit the menagerie of animal nomenclature for load shapes that diverge from a traditional curve. The term "shark curve" also seems particularly fitting given the substantial amounts of offshore wind planned for the Northeast. Big swings in net load can look like a shark's fin, Jaws-like snout, and tail disappearing after charging up at random hours during random months in the year (Figure 14).

[22] The "Shark Curve" has already been coined to reflect the unmet demand in developing countries tied to inadequate infrastructure as published in Greentech Media, "Introducing the Shark Curve," May 22, 2018, https://www.greentechmedia.com/articles/read/introducing-the-shark-curve.

[23] The "Shark Curve" also has been used to refer to electric vehicle load in developed countries, ARC Advisory Group, "How Will EV Adoption Change the Electric Demand Curve?" June 14, 2019, https://www.arcweb.com/blog/how-will-ev-adoption-change-electric-demand-curve Given the assumption that policy makers will adopt a time-of-use charging tariff and electric vehicles will incorporate automatic charging protocols to charge during low-priced hours, the analysis has minimized the impact on peak load associated with electric vehicles.

Figure 14: Examples of the "Shark Curve" using Model Input Assumptions[24]



The combination of New England's renewables coming online creates dramatic requirements for ramping capability. Figure 15 illustrates the increase in maximum hourly and bi-hourly ramping requirements for each year between 2022 to 2030. By 2025, the combination of renewables, energy efficiency and load can create a two-hour ramp requirement of nearly 5,000 MW, which increases to nearly 7,000 MW by 2028.

The one-hour ramp is lower, but similarly escalates over time as more renewables come online. By 2028, hourly ramp requirements reach 4,000 MW. In other words, ISO-NE will need to have at least 4,000 MW in flexible capacity with intra-hour ramp capabilities ready to go to protect the system against a sudden drop in renewable output.

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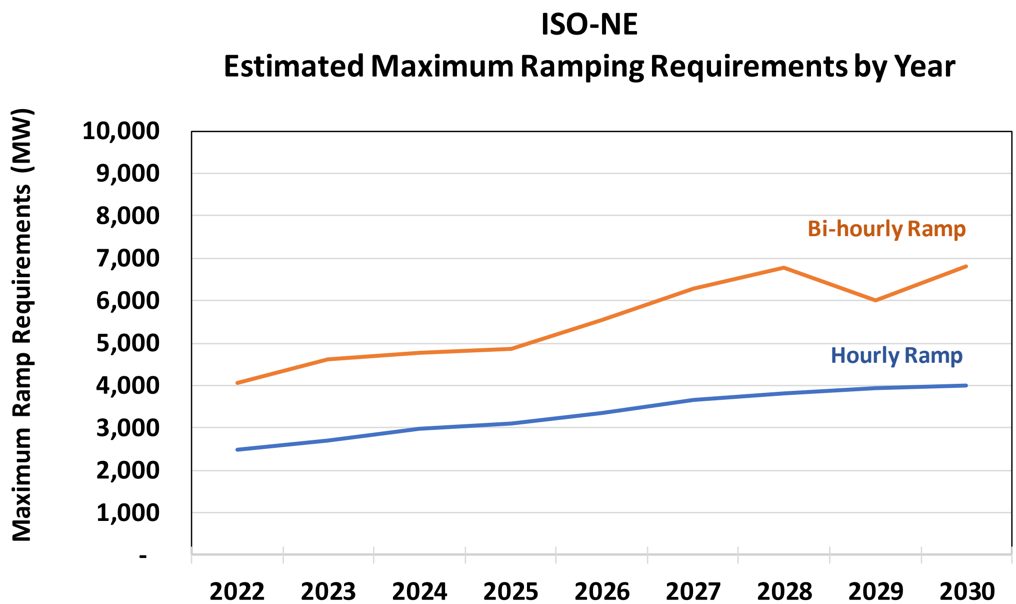
[24] Calculated using the hourly net load assumptions less grid-scale solar output, behind-the-meter solar, offshore wind, and on-shore wind profiles for each zone at the assumed level of integration.

Figure 15: Increased Ramping Requirements



ISO-NE is responsible for ensuring that there are sufficient reserves available to meet unit contingencies. Existing spinning and non-spinning reserves are based on unit contingencies such as a large plant or transmission line outage. These contingency reserves are separate and apart from the ramping requirements that increasingly will be needed to cover a simultaneous decrease in wind and/or sun as an increasing amount of renewable resources come online. Reserves from longer-term ramping resources with stored fuel (i.e., 90-minute and 240-minute ramp associated with ESI) also are separate and distinct from the ramping reserves that ISO-NE increasingly is going to require.

Going forward, either the definition of unit contingencies needs to expand to include potential output drops in renewable resources or a new type of flexibility reserves to respond to such changes will be required. In either case, Northfield is an ideal resource to meet those fast-start and quick ramp needs. A contractual dispatch that allocates Northfield to the highest priced hours in the day-ahead market serves to mitigate some of the ramping requirements. In the event additional ramp is required outside of the contractual dispatch hours, all four Northfield units can respond.

As the growing need for flexibility reserves shows, value provided by grid-scale storage is not currently measured and rewarded by ISO-NE markets. In addition to increasing reserves for short-term ramping needs, adequate capacity with fast-ramp capability will need to be procured to ensure system reliability.

6. NORTHFIELD IS COMPETITIVE VERSUS OTHER ENERGY STORAGE

Battery storage is a technology that is gaining traction politically and commercially. Two leading contenders for implementation in New England include lithium-ion battery energy storage systems and liquid air energy storage ("LAES"), a technology recently gaining ground. Sites for more established technologies such as new pumped hydro or compressed air energy storage either are not available in New England or could be prohibitively expensive.

Although battery energy storage systems ("BESS") are decreasing in cost, they remain relatively expensive and have yet to achieve significant economies of scale. LAES has gained traction globally; the technology uses energy to cool air until it liquefies, stores the liquid air in a tank, and then brings the liquid back to a gaseous state that is used to turn a turbine and generate electricity. The characteristics of LAES are more similar to Northfield in terms of unit capacity and associated discharge time.

Figure 16 lists a set of starting costs for batteries to place the relative costs of contracting with existing pumped storage as opposed to entering into a contract with a battery developer that could supply equivalent ramping and environmental benefits.

Figure 16: Comparison of Battery Costs

Storage Parameters	Battery Energy Storage Systems (Li-ion)			Liquid Air Energy Storage		
Capacity (MW)	5-25	10	200	40	100	400
Associated Discharge Time (hours)	5	0.25	0.25	4-10	4-10	4-10
Investment Cost ($/kW)	1,800-2,150	550	330	1,200 – 1,550	1,100 – 1,450	900 – 1,200
Fixed O&M ($/kW-yr)	30-40	15	10	7-9	6-8	6-8
Warranty ($Million/year)	0.085-0.4	0.025	0.50	NA	NA	NA
Data Source	Surveys of technology providers (2019), NREL			Survey of technology providers (2019), public information		

Battery storage developers generally are requiring an annual warranty payment each year. This technology does not reflect a system with the same long-term duration discharge operating characteristics of Northfield. To achieve the equivalent of 2 units at 292 MW that could charge during low-priced hours and shave the equivalent of five high-priced hours would be prohibitively expensive with respect to the upfront investment cost when compared to Northfield, even with subsidies. BESS simply are not designed to be able to compete with pumped hydro storage facility size and duration.

To realize the equivalent of 292 MWh each hour over a five-hour period would require something more akin to an LAES system, which can have a similar scale and discharge time as Northfield. The capital costs of such a system financed at around 5 percent over a seven-year period would require $90 million to $150 million per year before subsidies.[25] If financed over a fifteen-year period, corresponding to an estimated 20-year life, annual capital cost payments would be $50 million to $67 million per year[26] LAES currently is a more expensive alternative than contracting with an existing energy storage asset such as pumped hydro.

Costs for BESS and LAES are projected to continue to decline, but estimated gains vary. The National Renewable Energy Lab ("NREL") projects potential cost declines of 25 percent to 80 percent by 2030; LAES cost declines are more gradual (Figure 17). Existing pumped hydro storage remains the most cost-effective grid-scale energy storage option for long-duration discharge for the near-term. Energy storage options offer a much more expensive alternative for accessing excess clean energy during over-generation periods or where superior on-peak economics can be achieved. Although costs associated with these energy storage technologies are falling, they still are not competitive with utilizing an existing storage facility.

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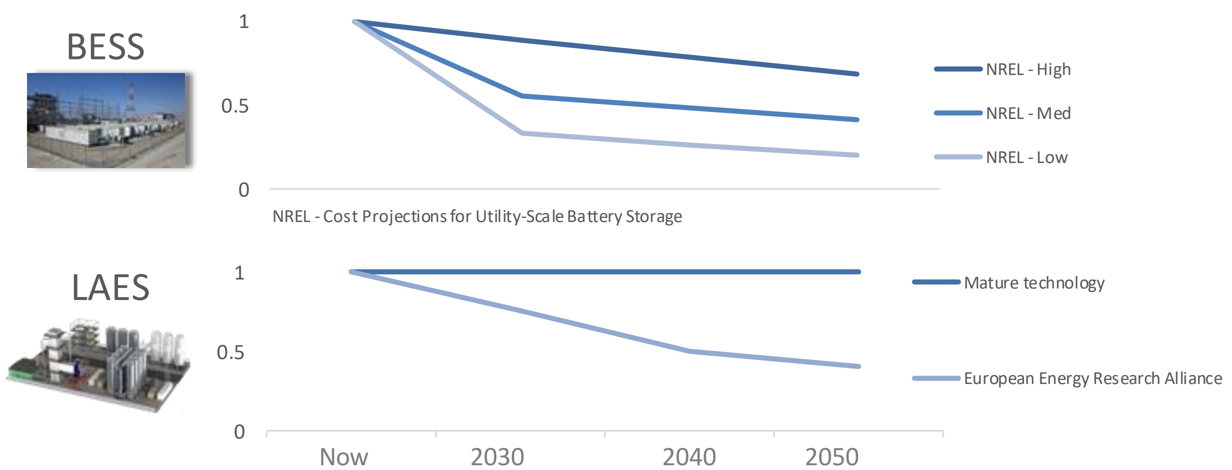
[25] The seven-year loan term is less than a 9-year contract because lenders would require the loan to end before the end of the contract. Capital costs are assumed to range between $900 to $1,200 per kW.

[26] The Federal government currently does not have stand-alone subsidies for grid-scale batteries. Any investment needs to be made in conjunction with or supporting a renewable energy supply source in order to be eligible for the federal Investment Tax Credit.

Figure 17: Potential Energy Storage Cost Declines



As energy storage solutions become commercialized, they will continue to have a difficult time competing with Northfield's large, long-duration energy storage capabilities. Batteries face competitive challenges from both efficiency ratios, high cycling costs (i.e., consumption of battery cell life) and recharging limitations that decrease effectiveness over time. In contrast, Northfield has improved its efficiency ratios with capital investment and, operational for more than 40 years, experiences very little "recharging" degradation. Lastly, whereas energy storage technologies offer different tradeoffs between storage cycles and response time, Northfield is a flexible energy storage resource that can vary its output to meet system needs:

- **Storage Cycles:** Northfield generally pumps and dispatches on an intra-day cycle, but it could cycle over longer or shorter periods of time to optimize against market conditions.

- **Response Time:** Northfield can respond from zero output to maximum capacity within 10 minutes, or could ramp up more slowly to respond to system needs over a longer period of time.

Northfield is a flexible resource that can utilize and optimize the region's clean energy investments more effectively than current storage alternatives and at a more cost-effective price.

7. CONCLUSION

Northfield is a unique power asset, cost-effectively providing flexibility that New England's power system requires as well as a number of other system-wide benefits. Currently offering energy, capacity and ancillary services to ISO-NE, Northfield operates as a merchant facility, operating only when it is economic to do so. However, there are a number of other value propositions that Northfield offers the region that could be realized via a contracted arrangement:

- **Reduced Carbon Emissions:** Northfield operations offer substantial reductions in regional carbon emissions by displacing higher emitting carbon generators during peak hours which more than offsets carbon emission increases that may occur during pumping, resulting in a net emissions reduction.

- **Peak Price Reduction:** Under projected conditions, Northfield can shave peak prices and lower energy prices in Massachusetts and throughout New England as additional renewable resources come online.

- **Improved Energy Security:** During extreme weather conditions, Northfield can reduce reliance on natural gas by displacing less efficient natural gas-fired peaking units and using more efficient generators during off-peak hours. When dual-fuel and oil units provide fuel diversity in such situations, Northfield can displace the higher carbon emissions that they would otherwise generate.

- **Fast-ramp Reserves:** Northfield offers New England fast-ramp reserves to meet the increasing need for flexibility created by integration of renewable resources onto the Northeast system.

As renewable integration increases, zero emitting resources increasingly will be on the margin, especially during off-peak hours. Even when the New England energy mix approaches 2030 renewable energy targets, Northfield offers a cost-effective means of utilizing those resources which would otherwise be wasted. In the interim, operating Northfield on a daily basis can decrease carbon emissions in New England by over 180,000 metric tonnes per year on average and by over 80,000 metric tonnes per year in Massachusetts, from 2022 through 2030.

Perhaps most importantly, these environmental benefits can correspond to decreased costs to consumers. Northfield operations that focus on daily peak shaving can suppress energy prices on a net basis. Although the incremental demand during pumping may increase prices, price reductions generally are projected to be even higher during high-priced hours when Northfield generates, resulting in a net decrease in cost to load. Running Northfield under a daily output contractual requirement indicates that Northfield's projected operations from 2022 to 2030 could reduce cost to load for New England customers by over $410 million and by over $220 million for Massachusetts (in $2018).

In addition, Northfield offers quick-response ramping reserves and energy security by displacing natural gas demand in New England. As these functions become more valuable with increased renewable integration, a contract with two of Northfield's four units focused on delivering energy the equivalent of 5 hours per day would mitigate the need for ramping resources and would allow Northfield to continue to provide ramping and fast-response ancillary services to maintain reliability in ISO-NE energy markets outside of the contracted output hours.

In summary, Northfield provides a number of value propositions – many of which are not fully realized under ISO-NE markets and existing compensation structures. This shortfall adversely impacts Northfield as well as other grid-scale battery storage resources. A contract can be used to increase Northfield dispatch and the associated benefits that the plant can provide without sacrificing its value in providing fast-ramp reserves in ISO-NE markets as the region increasingly integrates renewable energy.

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APPENDIX B:
Technical Description of PLEXOS Model

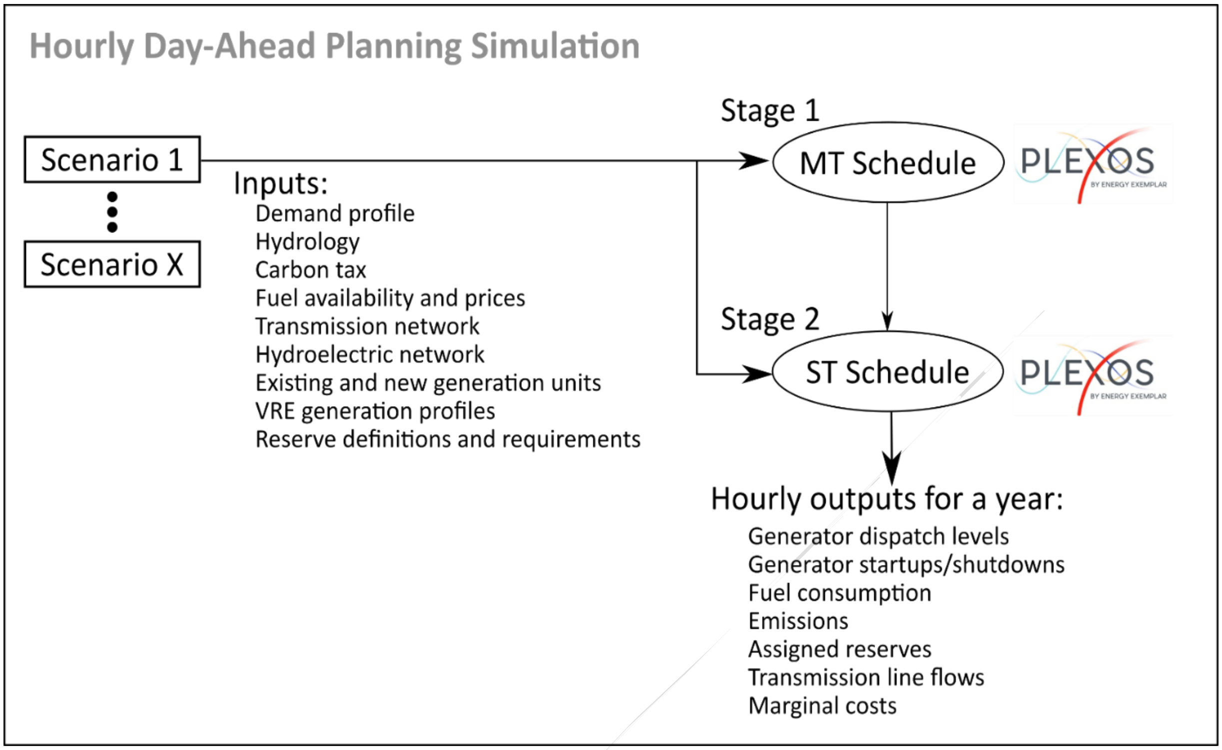
In this study, Energyzt used the PLEXOS market model by Energy Exemplar to forecast future electricity prices, generation, fuel consumption and carbon emissions under alternative Northfield operating scenarios. PLEXOS is a detailed optimization model that simulates the hourly operation of individual generating units and power flows across the transmission system within an electricity power pool or across regional transmission operators. PLEXOS is widely used in the electricity industry and includes both zonal and nodal databases for the Eastern Interconnect, the broader system within which ISO-NE and Northfield operates.

B.1. DAY-AHEAD ENERGY MARKET SIMULATION

Energyzt used PLEXOS to model the day-ahead energy market for the Eastern Interconnect zonal database for years 2022 through 2030. An hourly dispatch simulation model was set up to represent the day-ahead planning process carried out by the Regional Transmission Operators ("RTOs") and energy balancing authorities. Dispatch conditions such as power generation of each unit, flow through transmission lines, energy prices at busbars, and reserves provided by each unit, were calculated for each model run.

The short-term operations planning of an electric system with existing reservoir hydroelectric generation capacity must consider a medium-term strategy for the use of stored water resources, such as those in New England and surrounding markets such as Québec which impact prices in ISO-NE. Otherwise, any short-term dispatch model simulation would lead to excessive use of water resources without regard for future costs. PLEXOS includes a pre-processing tool (MT Schedule) that performs this optimization and then feeds the inputs into the ST Schedule. The model runs used a two-stage modeling approach to simulate operations in each scenario, shown in Figure B1.

Figure B1: Schematic of the Two-stage Modeling Approach



Stage 1: Medium-Term (MT) Schedule
The *PLEXOS* MT Schedule ensures that the dispatch and pricing impact of constraints such as energy limits and storage targets, and financial impacts of medium-term trading strategy, is correctly accounted for in the short-term schedule. The MT Schedule was used for the coordination of hydrothermal generation throughout each simulated year. In this stage, the optimal dispatch was found for each scenario.

The volume (or level) of stored water reached by the end of the year in all large reservoirs is assumed to be the same as the initial volume (or level) of stored water. The method used to optimize dispatch used in the MT Schedule considers some simplifications over what is traditionally performed to optimize the short-term operations to ensure that the optimization problems are manageable in size for each simulated year.

Stage 2: Short-Term (ST) Schedule

The PLEXOS ST Schedule solves the Unit Commitment problem to find the hourly dispatch in each scenario that complies with the targets and minimizes the operational costs. The dispatch model used in the ST Schedule considers more detailed operational constraints than the model used in the MT Schedule.

B.2. COMPARISON TO REAL-TIME ENERGY MARKET SIMULATION

Under day-ahead planning simulations, the effects of short-term uncertainty that manifests itself in real-time markets are not captured. In actual operations, the system operator commits certain units in advance based on expected system conditions. However, the real-time market deviates from the dispatch plan because unplanned events or unexpected constraints occur. In such cases, the real-time market covers units turning on or off, re-dispatches online units, sheds load, disconnects generation units, switches transmission lines, or applies other approaches to address unplanned for constraints. As a result, the energy prices observed in real-time operations can differ on an average basis as well as with respect to volatility and range when compared to energy prices in day-ahead markets.

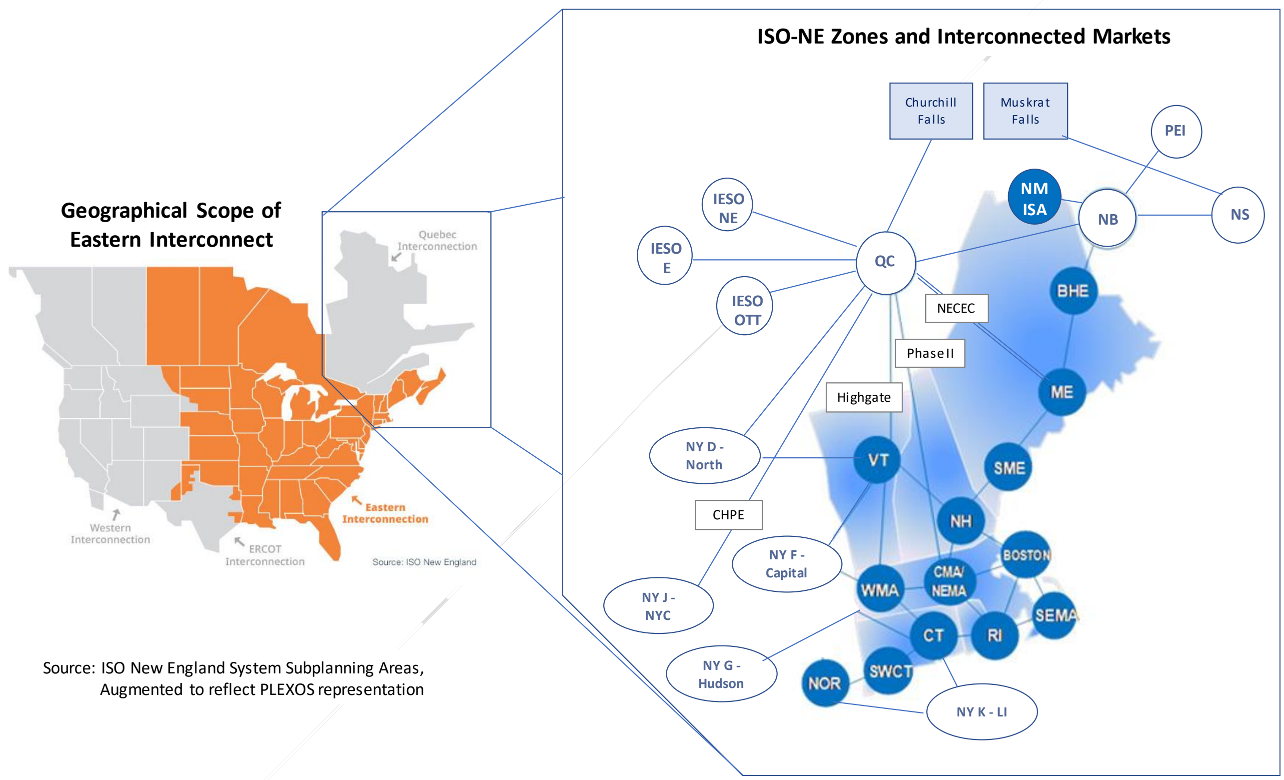
In day-ahead planning simulations, the optimal dispatch is determined with perfect foresight of unit availability, profiles of load and of renewable energy generation, activation of environmental constraints, and other known features of the system. Thus, the system's response when a large generation unit trips or when load or renewable energy generation levels significantly deviate from their forecasts cannot be captured through day ahead simulations. Day-ahead simulations also would have fewer instances of negative energy prices and significant price spikes tied to unanticipated excess and shortages.

In addition, the zonal database contains a limited representation of the transmission system in ISO-NE and the rest of the regions. Therefore, transmission congestion and negative pricing associated with localized constraints are not likely to be captured as part of the resulting simulations.

B.3. EASTERN INTERCONNECT

Energyzt ran the PLEXOS zonal model for the entire Eastern Interconnect plus interconnected Canadian regions for the years 2022 through 2030. The model represents a total of 97 zones across 15 markets. New England is represented by 13 zones based on the ISO-NE planning areas zones. The Northern Maine Independent System Administrator is separately connected to New Brunswick (Figure B2).

Figure B2: PLEXOS ISO-NE Representation in the Context of the Eastern Interconnect



Source: ISO New England System Subplanning Areas, Augmented to reflect PLEXOS representation

The ISO-NE market representation includes interconnections to New Brunswick, Québec, and New York. Every zone directly connected to ISO-NE was modeled with updated information. Imports and exports flow according to either contract requirements (when public) or economics. The level of detail varied by market. For example, Quebec, New Brunswick, Nova Scotia and Prince Edward Island each have a single zone representation.

New York and Ontario each have eleven zones. These zones are interconnected to each other and beyond with transmission lines that have a maximum and minimum capacity, assumed losses, and wheeling charges. Subject to those constraints, the model allows for energy to flow across interconnected markets based on excess supply in each market (i.e., generation less load) subject to economics.

The Newfoundland & Labrador system is not included in the model representation with two exceptions:

1) **Churchill Falls:** A portion of Churchill Falls is modeled within the Québec system to reflect the high voltage transmission lines that connect that facility to Québec along with the terms of the contract between Hydro-Québec and Nalcor. Power generation under contract is assumed to track Québec's load subject to maximum capacity limits and a reduction for losses equal to 7.5 percent of total generated.

2) **Muskrat Falls:** Represented as a generation resource into Nova Scotia via a 500 MW high voltage transmission line. Deliveries are assumed to be baseload, and any excess energy in Nova Scotia can flow into New Brunswick and beyond based on economics.

The purpose of the PLEXOS simulations is to quantify, for the ISO-NE electricity market, potential benefits of operating Northfield more frequently than it would otherwise operate as a merchant facility. PLEXOS was run to simulate what the ISO-NE market would be if each of the New England states, New York and Quebec achieve their carbon reduction goals and electric vehicle programs through 2050, with interim goals achieved along the way.

In this context, Northfield was dispatched in two different ways:

1. **Merchant Case:** Northfield operates as a merchant facility based on an assumed variable operations and maintenance cost plus bid adders provided by FirstLight for each unit; and

2. **Contract Case:** Northfield operates as a contracted facility at the highest-priced hours per day with a daily minimum generation requirement of 1,460 MWh each for Units 1 and 2 (i.e., equivalent to Units 1 and 2 operating five hours each day at 292 MW maximum capacity). Pumping is optimized across all four units at the lowest priced hours. Units 3 and 4, as well as excess capacity on the contracted units, is dispatched economically based on the bidding strategy provided by FirstLight for each unit.

For each zone, PLEXOS generates a number of data outputs including, but not limited to:

- Carbon emissions generated in each hour
- Cost to load in each hour
- Energy prices by zone for each hour
- Hourly plant dispatch

Benefits are calculated for each year using the cost to load and carbon emissions generated by PLEXOS by zones in Massachusetts and New England to determine the impact of the assumed contract.

APPENDIX C:
Assumptions

This appendix describes the primary assumptions that were incorporated into the market model. Key assumptions for any production cost model include the following:

- **Demand:** Peak and energy demand forecasts are input into the model on an annual basis and converted into hourly demands using historical demand patterns.
    - Demand for New England, New York and Québec was increased to reflect fixed electric vehicle programs and heat pump initiatives through 2030 based on the targeted goals established by each state across the years through 2050.
    - Nearly all of electric vehicle load was assumed to be price-responsive, charging during the lowest-priced periods; only 2 percent was assumed to be uniform across all hours, based on Energyzt analysis of charging profiles developed by NREL.
    - Demand response was modeled as dispatchable units with a $200/MWh price up to projected demand response levels.
    - Additional scarcity units were modeled at higher dispatch prices to reflect involuntary demand response (e.g. outages).

- **Supply:** Existing generation is modeled at the unit level, based on historical operating characteristics, including capacity, variable operation and maintenance costs, heat rates, emissions rates and other operating parameters such as minimum up and down times. Behind-the-meter solar was modeled as generators with zonal shapes.

- **Capacity Build-out:** New generation is based on announced projects that are under construction or, in some cases, permitted. The characteristics of new generation are based on existing units, or expected technologies, as appropriate given stated policy goals.

- **Fuel Costs:** Forecasted fuel prices for coal, gas and oil are represented on a weekly, monthly or annual basis as appropriate and are incorporated into the calculation of the marginal cost of production for each generating unit.

- **Emissions Costs:** The cost of emissions is incorporated into the marginal cost of production. Forecasted prices for CO_2 allowances are combined with assumed emissions rates for each unit, to give an emissions cost per MWh for each unit.

- **Transmission:** PLEXOS contains a representation of the entire Eastern Interconnect, including the ISO-NE transmission system and interconnections. In the zonal model, transmission is modeled as a pipeline representation between zones with minimum and maximum capacity, losses, and wheeling charges.

In conducting this analysis, Energyzt started with a PLEXOS-supplied database for the Eastern Interconnect. This was significantly updated using publicly-available energy market data, specifically:

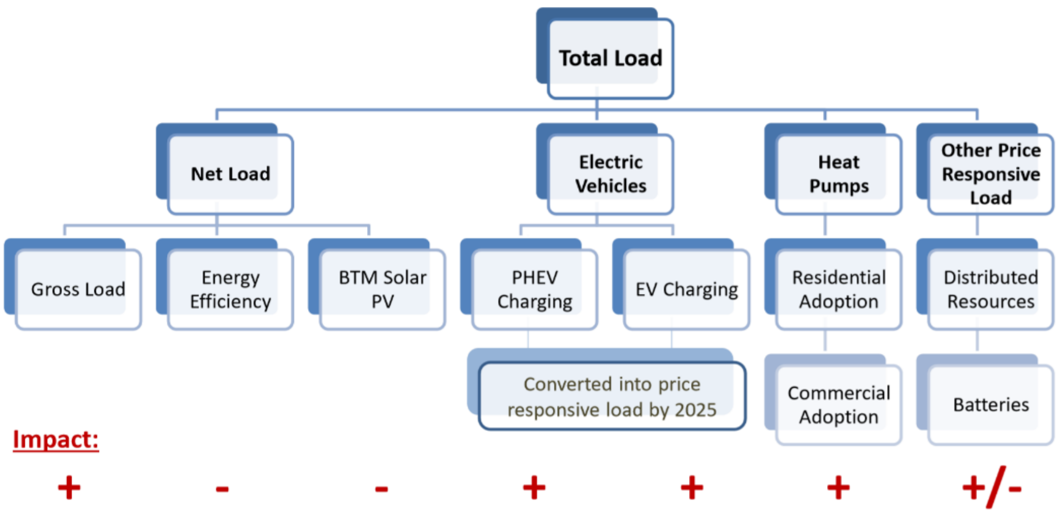
- ISO-NE CELT Reports: 2019 reports issued by ISO-NE covering demand, generation and transmission
- EIA Data: Generating unit data from EIA Form 923, Capacity Supply Obligation reports, and industry specifications by technology types
- EIA Fuel Price Projections: Fuel price forecasts, primarily based on the U.S. Energy Information Administration ("EIA") Annual Energy Outlook 2019
- Carbon Prices: Assumed emissions allowance prices

A more detailed description of key variables is provided below.

C.1 Demand Forecasts

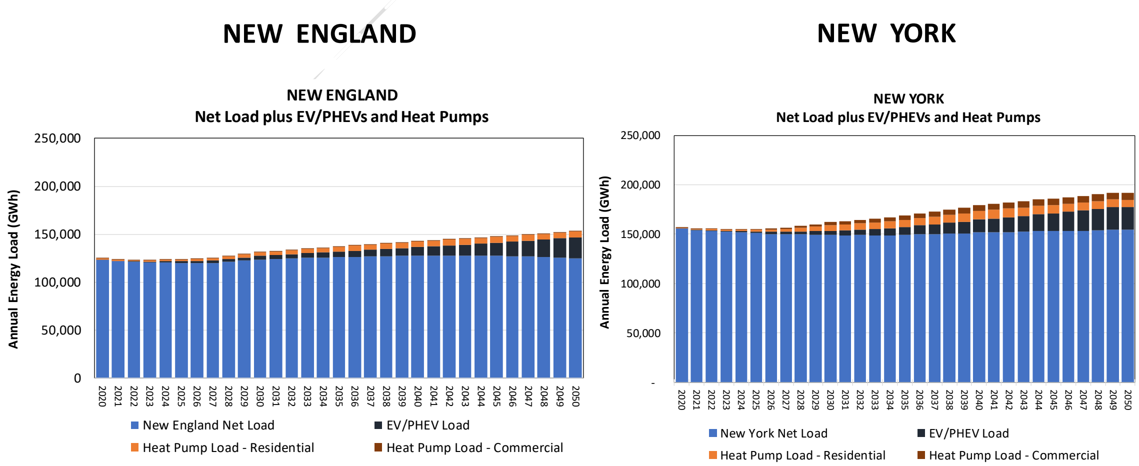
Electricity demand is represented by hourly demand forecasts for each zone. These demand forecasts are constructed using historical hourly load patterns for each area, combined with annual peak load and energy forecasts based on ISO-NE projections plus Energyzt projections for increased demand tied to policies promoting heat pumps and electric vehicles (Figure C-1).

Figure C-1: Factors Impact ISO-NE Load Assumptions through 2030



Total load is a combination of assumptions. Net load, Electric Vehicles, Heat Pumps, and Other Price Responsive Load discussed in more depth in the following subsections. The combination of these different factors results in a total increase in load for both New England and New York (Figure C-2)

Figure C-2: Projected Load Growth through 2050 to Achieve Carbon Goals



The methodology and assumptions used to project each component of load is described in the following subsections.

C.1.1 Net Load

ISO-NE's demand forecasts are based on estimates of the underlying rate of historical electricity growth, with separate bottom–up forecasts of the effect of energy efficiency (passive demand response) and of the growth of behind-the-meter solar ("BTM Solar"), both of which are growing substantially and reduce demand and lower overall growth rates.

To develop the assumptions for New England load, Energyzt relied on the ISO-NE 2019 CELT report which provides forecasting values by state and is used by the grid operator to develop long-term forecasts.[1] Forecasts however only extend to 2028, requiring additional assumptions to be made in order to extend the forecasts out to 2050. Growth rates to 2030 used the 2028-2029 growth rates for each of the components of net load. Growth rates beyond 2030 to 2050 assumed the following rates based on historical trends:

- Gross Load: 1.25%
- BTM Solar: 7.19%
- Energy Efficiency: 2.89%

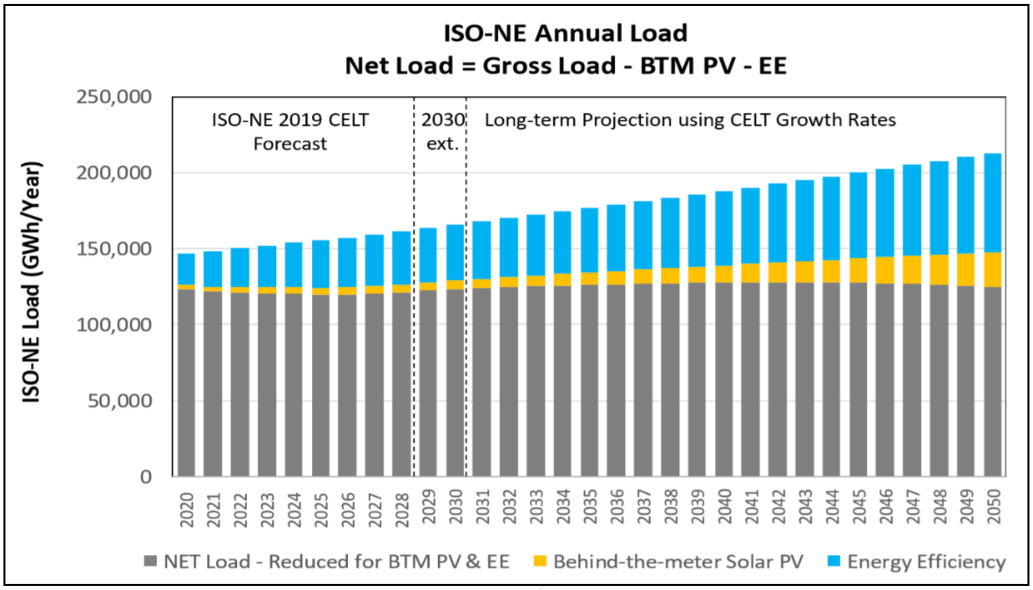
BTM Solar includes a much higher growth rate as forecasts indicate more residents are likely to engage in this type of distributed generation going forward. This expectation matches historical trends and economic projections that indicate solar will be competitive with alternatives and a key component of states achievement of their carbon emissions reduction goals. Under the growth rates above, energy generated from BTM Solar would serve roughly 15.5 percent of net load by 2050.

As a result of growth in BTM Solar and energy efficiency, net load is projected to remain relatively flat (see the gray bars). This is consistent with current policies that promote these resources and offsets in solar and energy efficiency as states look to reduce carbon

[1] CELT Reports, 2019, https://www.iso-ne.com/system-planning/system-plans-studies/celt

emissions and promote clean energy. Projected annual energy demand forecasts incorporated into the model are shown in Figure C-3.

Figure C-3: ISO-NE Projected Hourly Load, Energy Efficiency and BTM Solar



For purposes of the model, gross load less energy efficiency was incorporated into load input files (along with the baseload electric vehicle demand and projected demand from heat pumps). While forecasted totals for net load were developed on an annual basis, one last step was needed to break them down to hourly values. For this, Energyzt used the hourly net load shape from a representative year with a summer peak in July and no significant winter weather event.

The load shape was applied by zone based on the actual consumption in that zone during the representative year. By multiplying the annual net load forecast by a daily percentage of annual load for each zone using the load shape, hourly net load values were created and updated into the model. Energy efficiency was assumed to follow the same load shape.

BTM Solar was incorporated as generating units so as to be able to apply hourly shapes to production for each zone and to measure renewables as a percentage of net load for purposes of ensuring that each state met their renewable portfolio standards.

C.1.2 Electric Vehicles

In recent years the number of electric vehicles ("EVs") on the road has been increasing as more models become available coupled with shifts in consumer trends and the announcement of state mandated goals. As EV ownership rises, so too does the demand for electricity used to charge them. This "charging demand" is likely to challenge grid operations and therefore it is important to consider in future load projections.

In order to estimate the incremental demand from EVs, Energyzt developed forecasts through 2050 based on stated goals by states and Canadian provinces on carbon emissions reductions and programs regarding bringing electric vehicles online. Forecasts relied on a variety of assumptions for EV sales and stock, vehicle travel patterns, and vehicle efficiencies and models. Projections were performed for light-duty vehicles, medium/heavy-duty vehicles and buses.

Light-duty vehicle stock was calculated to provide a base for the number of EVs on the road today and how that existing stock would need to increase for New England states, New York and Québec to meet their announced electric vehicle goals. For this, 2017 vehicle registration data for each state served as a starting point.[2] Building off the 2017 data, the announcement of EV goals and mandates from each state were then applied to develop EV stock and sales estimates as follows:[3]

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[2] Auto Alliance, In Your State, https://autoalliance.org/in-your-state

[3] Connecticut DEEP Portal, https://portal.ct.gov/DEEP, Synapse Energy Economics Inc., "Massachusetts Comprehensive Energy Plan," July 17-19, 2018,

- Connecticut: Goal of appx. 500,000 EVs by 2030
- Massachusetts: Target of 300,000 EVs by 2025
- Rhode Island: Goal of 43,000 EVs by 2025
- Vermont: 10% vehicle electrification by 2025
- Maine: Intends to add 250 EVs to government vehicles and more than 1,000 in public EV sales over three years

After these and other stated goals for interconnected markets were met, Energyzt assumed 100% of all car sales would be electric by 2050. A retirement rate of 95% of new car sales was used (i.e. for every 1 car sold, 0.95 cars retire), consistent with historical rates. Also, because not all EVs are fully electric, projections considered the portion that are fully battery powered (Battery Hybrid Electric Vehicles or BHEVs that are 100% electric) and Plug-in Hybrid Electric Vehicles ("PHEV"), based on the U.S. Energy Information Administration's 2019 Annual Energy Outlook for the ratio of battery powered EVs to plug-in hybrids.[4] By 2050, the projections indicate 81% of new EV car sales would be battery and 19% would be hybrid.

Representing a much smaller portion of vehicle stock, medium/heavy duty trucks and buses also were projected, but with slightly different assumptions. For simplicity, 2017 registrations were once again used as the starting point. Slower adoption rates and

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https://www.mass.gov/files/documents/2018/07/20/CEP%20Stakeholder%20Meetings%20Presentation.pdf, Rhode Island Public Utility Commission, "People's Power & Light Answers to PST on Electric Vehicles," www.ripuc.ri.gov/utilityinfo/electric/PST_BE_SC_3.pdf

Vermont Public Utility Commission, "Promoting The Ownership and Use of Electric Vehicles In The State of Vermont," June 27, 2019, https://legislature.vermont.gov/assets/Legislative-Reports/Electric-vehicles-report-pdfA.pdf

[4] U.S. Energy Information Administration (EIA), Annual Energy Outlook 2019, January 24, 2019, https://www.eia.gov/outlooks/archive/aeo19/

technology challenges decreased vehicle stock projections in this category to 10% EVs by 2030, 35% by 2040 and 50% by 2050. Adoption during interim years followed an exponential adoption rate.

Once EV sales and stock projections were finalized, vehicle efficiency and travel patterns were incorporated to estimate what the ultimate change in load would be. Beginning with efficiency, Energyzt reviewed a variety of different EV models both currently available and those planned for the near future.[5] This provided a starting point for current vehicle efficiency on a mile per kilowatt-hour basis. Combined with historical changes in efficiency as well as a variety of case studies with vehicle projections, an assumption on vehicle efficiency through 2050 was developed. For light-duty BHEVs, an efficiency rate of 3.4 miles per kilowatt-hour was used as a starting point which was then increased at an annual growth rate of 1.24%, bringing the efficiency rate to 5.1 miles per KWh or 1.5x by 2050. Though currently lower at 2.5 miles per kilowatt-hour in 2017, trends in battery efficiencies indicate that PHEVs would improve at a slightly higher rate and therefore a 2x efficiency was used by 2050 or 5 miles per kilowatt-hour.

For medium/heavy-duty vehicles and buses that require much larger batteries, adoption rates and battery technology is lagging and therefore the efficiency assumptions remain much lower. After reviewing a variety of existing and new models, it was assumed medium and heavy-duty vehicles would start with an efficiency rate of 1.49 KWh per mile for BHEVs and 1.74 KWh per mile for PHEVs. Between 2017 to 2030 the efficiencies were assumed to improve by 14% overall and 17% from 2030 to 2050. Buses are expected to be slightly higher at 1.37 KWh per mile for BHEV and 1.59 KWh per mile for PHEV. The efficiency would then improve 12% by 2030 and 16% from 2030 to 2050.

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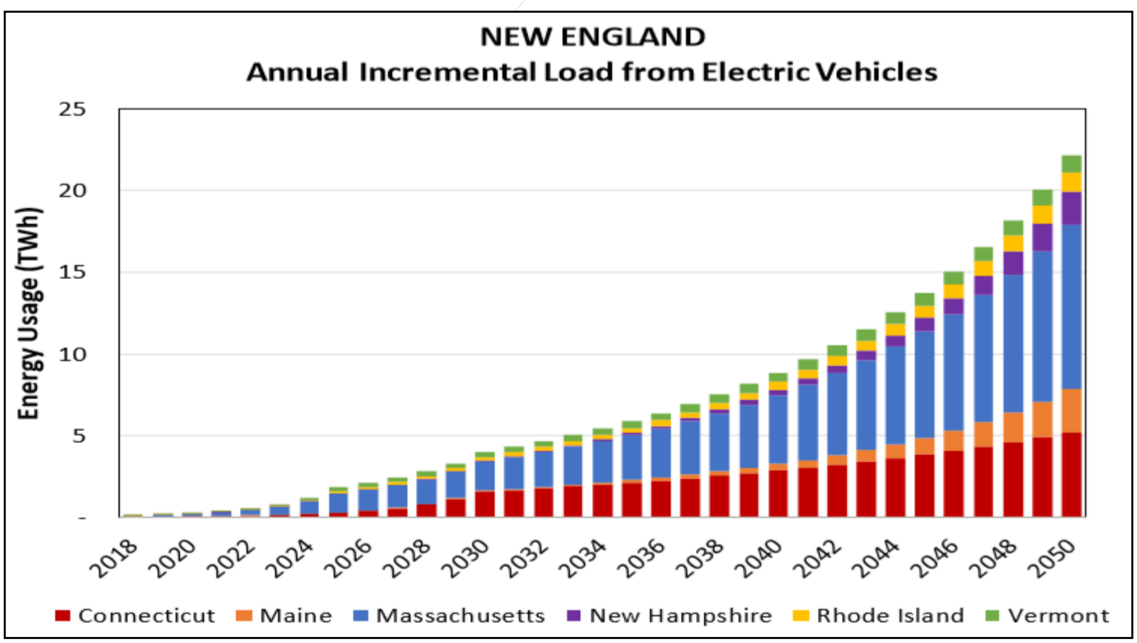
[5] U.S. Department of Energy, New & Upcoming Plug-in Hybrids, https://www.fueleconomy.gov/feg/phevnews.shtml

Finally, driving patterns must be incorporated to estimate how much energy (fuel) would be required, and for this, 2017 data on vehicle miles traveled per vehicle and vehicle classes were used. For simplicity, annual miles traveled remained consistent. Also, because PHEVs use gasoline for a portion of their travel, Energyzt assumed 55% of miles traveled were done so using electricity, a number that is consistent with recent car models.
Once all assumptions were finalized, the following calculation was used to estimate the total change in load.

Incremental EV Load = EV Efficiency X EV Miles Traveled X EV Stock

As seen in the chart below, due to the lower portion of EVs to gasoline powered vehicles in the early years, the impact to load remains low. Through 2030, annual electric load is projected to increase by around 4 TWh in New England. As adoption rates increase and mandates are met, EVs are expected to have a sizeable impact on energy demand, adding roughly 22.2 TWh of load to the system by 2050 (Figure C-4).

Figure C-4: New England Incremental Load from Electric Vehicles, 2018-2050



With annual electric vehicle load finalized, the last step was to input the data into the model in a way that reflects charging patterns. As a result, roughly 2% of EV load was entered as baseload energy which assumed vehicle charging occurs evenly across all hours based on NREL charging patterns. This constant value was allocated to each zone based on projected EV adoption in each zone, and added to the hourly net load.

The remaining 98% of electric vehicle load was assumed to be Time-of-Use charging where customers would charge at the lowest-priced hours as produced by the model. This load was allocated to each zone based on projected EV adoption for each state and modeled as a negative generator to "dispatch" when prices were most economic.

C.1.3 Heat Pumps

Both New England and New York have policies to convert fossil-fuel heating to a decarbonized grid. This conversion first requires an increase in carbon-free generation to occur. Once it starts to happen, electric load is projected to increase, especially during the winter months.

In order to project the impact of heat pumps, Energyzt performed the following calculations:

1) Understand state policies and compare to projected economics of different fuel types
2) Calculate housing stock and project future stock based on EIA population projections
3) Estimate relative proportion of different heating fuels
4) Convert home heating to heat pumps based on target adoption rates
5) Estimate incremental load associated with heat pump conversions
6) Shape load based on historical temperature patterns

This calculation was performed for both residential homes and commercial/industrial buildings. The end-goal was to arrive at a carbon emissions output for home heating that was low enough to achieve the carbon emissions reductions goals established by state policies.

Figure C-5 illustrates the conversion goals assumed for New England.

Figure C-5: New England Projected Demand Response, 2019-2050

Projected Impact	New England
Residential Heat Pumps	51% by 2050
2030	1.0 million
2040	2.3 million
2050	3.0 million
Commercial Heat Pumps	Percentage mBtu Conversion
2030	2.9%
2040	6.7%
2050	8.3%
Annual Heat Pump Load	
2030	4.0 TWh
2040	6.6 TWh
2050	6.8 TWh
Monthly Peak Load	
2030	0.7 TWh
2040	1.2 TWh
2050	1.2 TWh

C.1.4 Demand Response

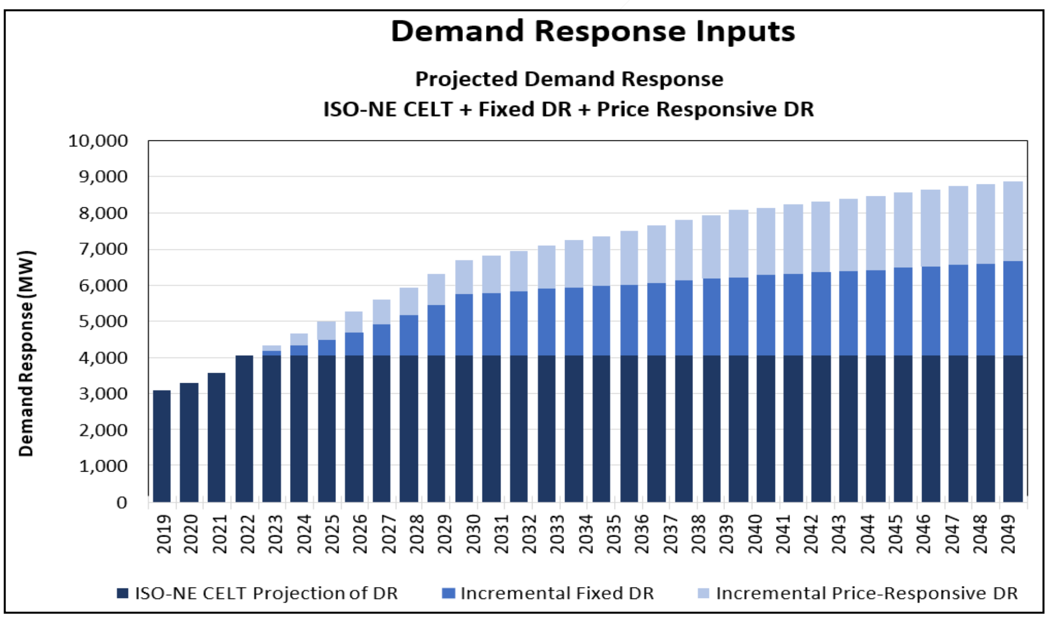
Demand Response resources are a key part of state policies focused on reducing carbon emissions. They are considered a capacity resource in centralized capacity markets as well as by NERC's long-term reliability assessments. These highly valued resources are critical to ensure smooth grid operations and are most effective during periods of high demand through peak load shaving, helping to avoid energy shortages and energy price suppression during price spikes. As already noted, the model incorporates most of the electric vehicle load into the model as price-responsive demand to charge during low-priced hours. Energyzt incorporated a number of other price-responsive demand resources into the model through 2050 that serve to decrease load during high-priced hours.

As a starting point, Energyzt used the ISO-NE 2019 CELT report for historical demand response levels as well as base level projections out to 2029 which were extended to 2050.[6] Demand response assumptions were projected according to the following three categories:

- Fixed Demand Response
- Price-Responsive Load
- Scarcity Resources

See Figure C-6.

Figure C-6: New England Projected Demand Response, 2019-2050



[6] CELT Reports, 2019, https://www.iso-ne.com/system-planning/system-plans-studies/celt

Fixed Demand Response

The base for demand response projections is ISO-NE's projection of fixed demand response through 2022. This is held constant through 2050.

Between 2022 and 2030, incremental fixed demand response was added based on the capacity from ISO-NE's Forward Capacity Auction 13 (FCA13) for units that qualified for the auction but did not clear.[7] All price-responsive demand that qualified for FCA13 was assumed to be active by 2030.

This fixed demand response load was modeled as negative generators with a bid price of $200 / MWh.

Price Responsive Demand

The model also includes an additional component of demand response ("Incremental Price Responsive Demand Response") based on a 2009 FERC Staff Study that addressed demand response potential by state for future years.[8] The report included a variety of scenarios that reflected changes in market conditions which included Business as Usual, Expanded Business as Usual, Achievable Participation, and Full Participation. Under each category a certain level of demand response was expected to be built.

As a starting point, Energyzt evaluated which of the four FERC categories the 2022 projections (historical plus FCA13 qualified capacity) for each state would fall into. Energyzt assumed that each state would add enough demand response capacity to move into the next FERC level each decade. For example, if demand response capacity was at a "Business as Usual" level, the state would achieve an "Expanded Business as Usual" level. Between 2030 to 2040 the same assumption was used and all states were then brought up to the next level. Finally, if any of the New England states had not reached the "Full

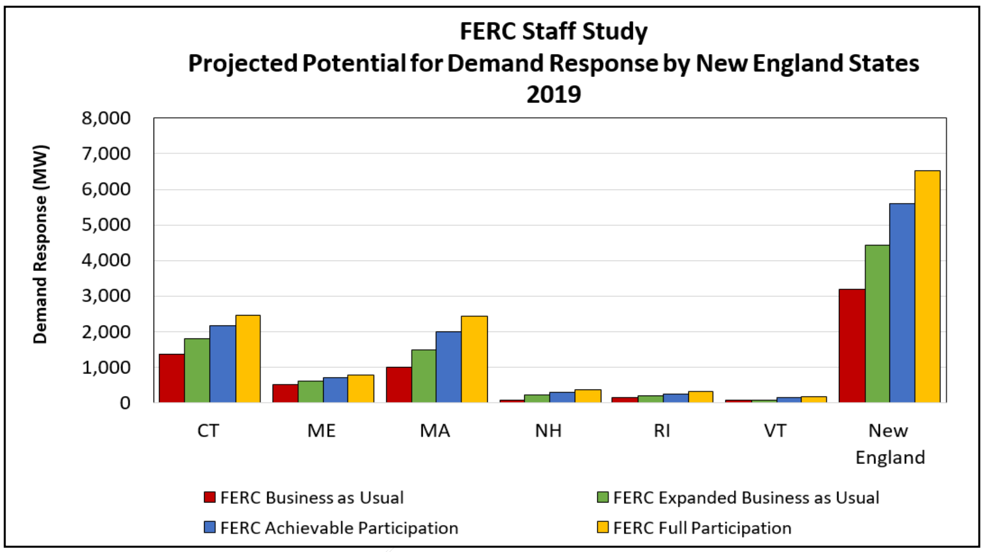
[7] Forward Capacity Market, https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/

[8] Federal Energy Regulatory Commission (FERC), "A National Assessment of Demand Response Potential," June 2009, https://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf

Potential" level by 2040 it was assumed they would add enough capacity evenly between 2040 to 2050 so that the "Full Potential" level was reached (Figure C-7).

Under these assumptions, New England's price-responsive demand totals 6,500 MW, with the majority provided by Connecticut and Massachusetts.

Figure C-7: FERC Staff Study, 2009 Demand Response Projections



Price-responsive demand also was included in other markets to reflect projected demand response under the NERC 2019 Long-term Reliability Assessment. This price-responsive load was modeled as negative generation units that bid into the market at a price of $200/MWh.

Scarcity Resources

Each market also includes scarcity resources to reflect forced outages or rolling black-outs that can occur during extreme weather conditions or in the event supply is insufficient to meet demand. These resources reflect more expensive distributed resources that can be used to offset load, future microgrids, and an opportunity cost to forego electricity. To establish a projection for these resources, Energyzt assumed a certain percentage of peak load less demand response in each year would respond to scarcity events as follows:

- 2022-2025: 2.5% of Net Peak Load
- 2026-2030: 5% of Net Peak Load
- 2031-2040: 10% of Net Peak Load
- 2041-2050: 12.5% of Net Peak Load

These resources were modeled as negative generators with a much more expensive pricing-dispatch methodology. Each unit was modeled with a linear bid price ranging from $1,000/MWh to $4,000/MWh.

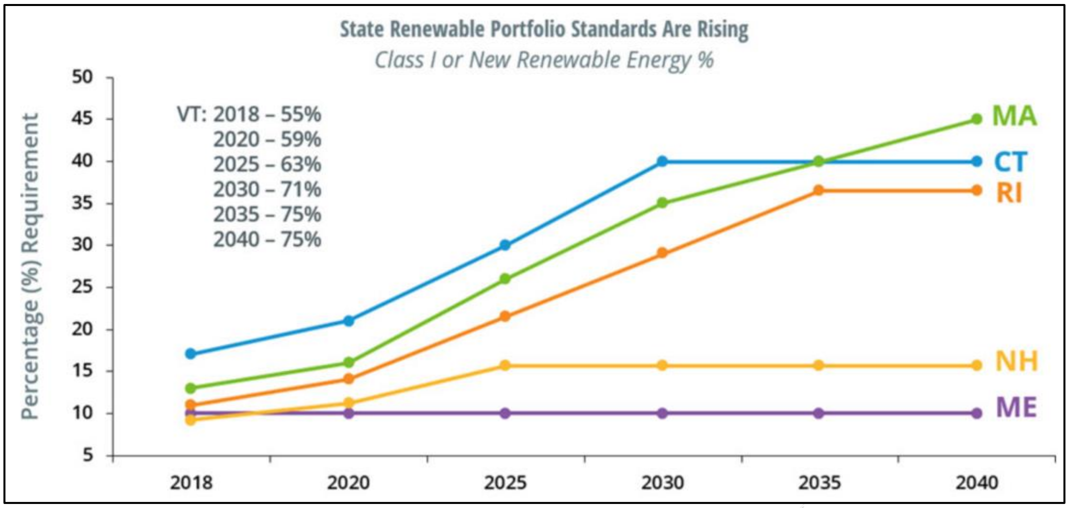
C.2 Generation Additions and Retirements

The future electric grid is expected to undergo a variety of changes as states increase goals and mandates for clean energy resources. The PLEXOS database used for the simulations includes the existing and expected thermal and renewable generation in the ISO-NE market over the period of the simulation. As the starting point for this analysis, Energyzt explicitly adjusted the database to reflect generators in FERC 923 data and the existing and planned generation listed in the ISO-NE Forward Capacity Market.

C.2.1 Generation Capacity Additions

Most of the generation additions slated for New England are renewable resources. These additions are driven by policy goals and state-by-state renewable portfolio standard targets (Figure C-8). In adding new capacity through 2050, the additions focus on meeting state targets followed by reserve requirements.

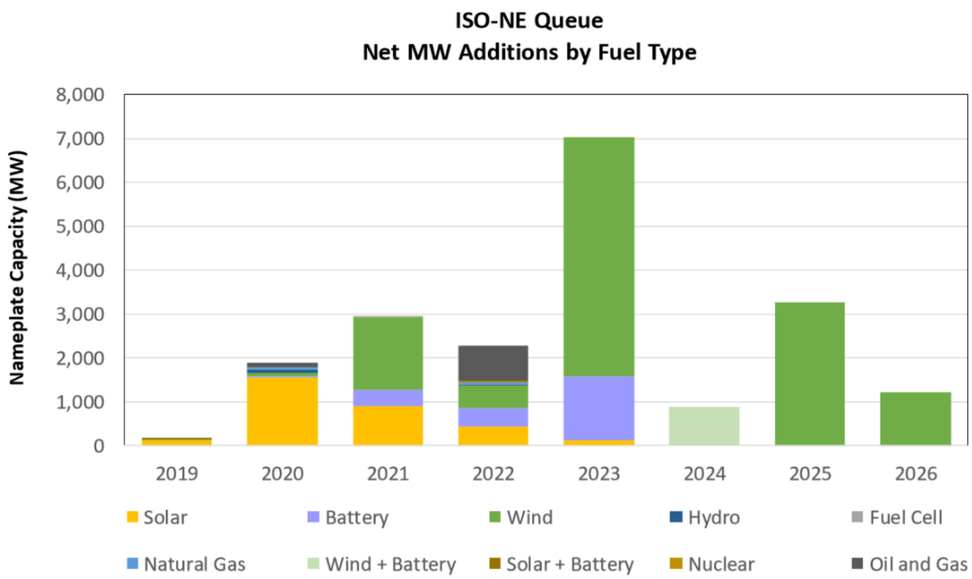
Figure C-8: New England State Renewable Targets[9]



The FCM provides a list of assured resources however there are many additional plants that do not bid into the auction but are still expected to be built. Energyzt also relied on the ISO-NE queue report. This report provides a list of all plants that have submitted interconnection requests to the grid operator and plan to be built. While there are many plants in the queue, roughly 70% of requests historically are withdrawn. Energyzt assumed that only those furthest along in the permitting or construction process would be built going forward through 2030. These resources are primarily wind and solar resources, along with some grid-scale battery. Most of the solar projects are front loaded between 2020 to 2022 along with the onshore wind while most offshore wind projects are not expected until post-2023 (Figure C-9).

[9] https://www.iso-ne.com/about/key-stats/resource-mix#on-the-way-in, Desire USA, http://www.dsireusa.org/; https://acadiacenter.org/wp-content/uploads/2018/08/Acadia-Center-Summary-of-2018-Clean-Energy-Legislation-in-MA.pdf, https://www.utilitydive.com/news/maine-gov-mills-introduces-100-renewables-bill/553928/

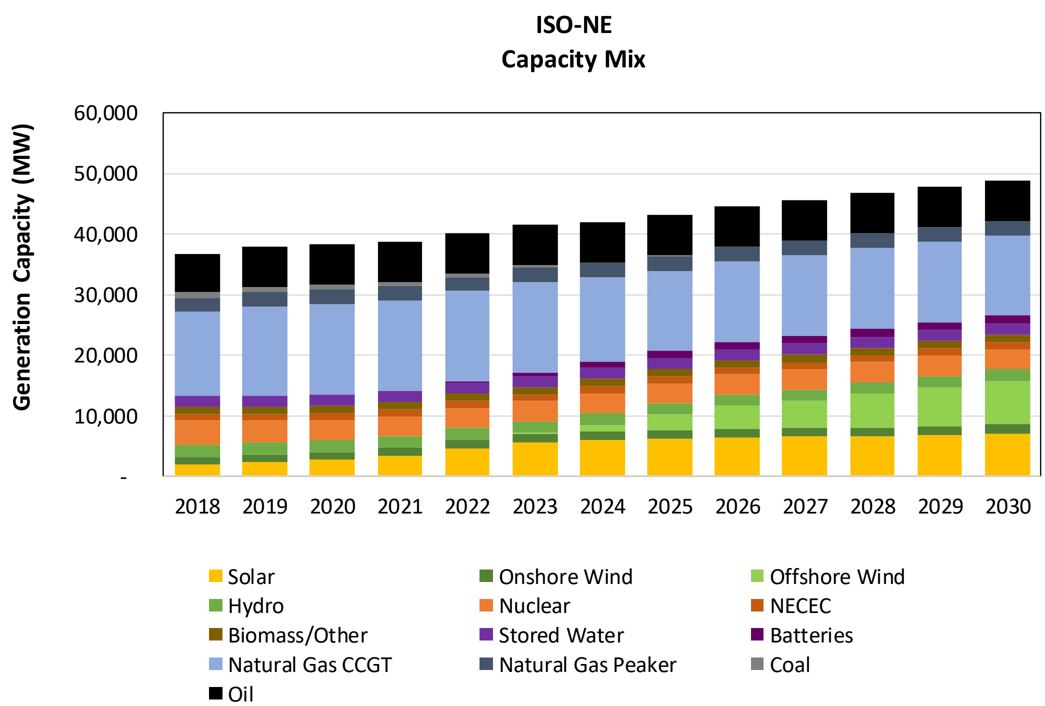
Figure C-9: ISO-NE Net Capacity Additions in the Queue



Given current delays in approval and the significant amount of wind resources with online dates of 2023, Energyzt shifted the online date of these resources to later dates to result in a smoother integration of renewable resources. Batteries that are included in the ISO-NE queue also were assumed to be built over time. By 2030, New England is assumed to have more than 7,000 MW of solar, approximately 1,500 MW of on-shore wind and 7,250 MW of offshore wind and nearly 1,350 MW of batteries on the system.

Figure C-10 illustrates the final total system capacity by fuel type that was built into the model through 2030.

Figure C-10: ISO-NE Nameplate Capacity by Fuel Type (2022 – 2030)



Through 2030, New England is in a condition of excessive supply. Other markets face tighter conditions. Whenever required, generic capacity additions were made to ensure that other markets in the Eastern Interconnect did not experience black-out conditions. In the case of Québec, new additions included Romaine-4 coming online and 500 MW of capacity upgrades in 2025. New hydroelectric facilities in increments of 250 MW were built as required to meet growing peak load requirements over time. Markets outside of the Northeast and eastern Canada included new additions of natural gas-fired units to balance their systems.

C.2.2 Generation Retirements

With resource additions in place, the next considerations required a review of what plants are likely to retire. ISO-NE's FCM data was used to generate a confirmed list of plants that will be retiring through 2025. The Mystic units were assumed to retire in 2024. By the end of 2028, any remaining coal plants in New England were assumed to have retired.

Although other units may become uneconomic under different scenarios, the model does not retire them, but allows for economic dispatch dictate operations through 2030.

C.2.3 Imports and Exports

ISO-NE is connected to NYISO, Ontario, Quebec and New Brunswick through six AC and DC interfaces. Power is imported and exported across these interfaces, with the magnitude of the import or export varying by time of day and month.

PLEXOS allows for imports and exports to flow according to economics. Input assumptions include line losses and wheeling charges. Generation capacity additions, reserve requirements and transmission assumptions were incorporated into interconnected markets to reflect consistent assumptions with respect to published data. Energyzt reviewed the PLEXOS outputs against historical conditions to confirm that the model produced similar results subject to projected changes in conditions.

C.3 Fuel Prices

Fossil fuel prices continue to be an important assumption in projecting generation dispatch and prices. This section describes the source for each type of fuel price.

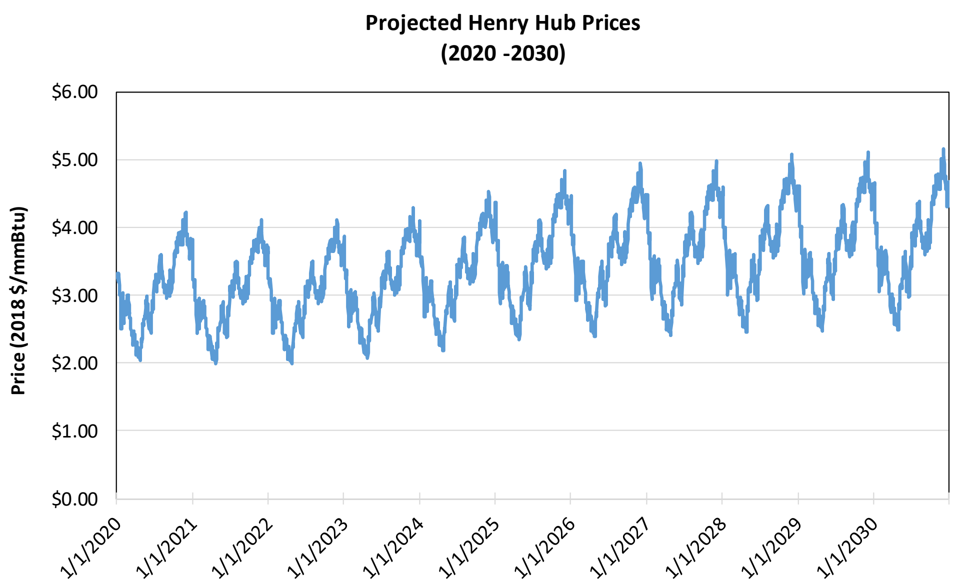
C.3.1 Natural Gas Price Forecasts

Natural gas prices incorporated into the model are based on three factors:

1) Henry Hub natural gas price projections by the EIA
2) Assumed monthly basis differentials for key delivery hubs
3) Local distribution delivery charges

Henry Hub prices were projected using the EIA 2019 Annual Energy Outlook (2019 AEO) through 2050.[10] They were converted to daily prices based on the 2012 pricing patterns in order to correspond to assumed hourly load patterns.

Figure C-11: EIA Forecasted Natural Gas Prices with Daily Shape[11]



Basis differentials through 2030 reflect historical monthly averages over the past five years. The same basis is applied at each delivery hub (e.g., Algonquin Citygate, Dracut, TETCOM3) for the entire month. For example, the basis for Algonquin Citygate ranges from -0.51 in September to +4.87 in February.

Within PLEXOS, each gas-fired unit is assigned a gas price based on the pipeline/hub that serves that site. Distribution delivery adders are included to reflect the specific location of each generator.

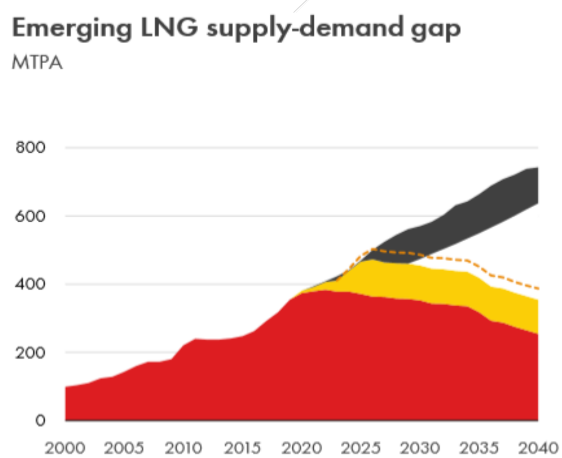
[10] Annual Energy Outlook 2019, January 24, 2019, https://www.eia.gov/outlooks/archive/aeo19/
[11] Ibid

C.3.2 Liquified Natural Gas (LNG)

Liquified natural gas continues to play a role in New England generation mix and it is expected to continue doing so as additional LNG refineries continue to get built around the U.S. LNG serves as a cap on natural gas prices in New England during the winter months when LNG deliveries serve as New England's natural gas "pipeline" to the east. Given the unique attributes of LNG and the required breakdown from its transportation form to ultimate use in generation, there are few forecast available on future pricing, particularly for the New England zones. The model assumes that LNG will average around $7.50 per year ($2018) going forward.

This projected price is significantly higher than where LNG currently is clearing. LNG prices tend to follow global oil prices, and the recent decline in oil has impacted LNG as well. As global demand for LNG continues to grow, however, projections indicate LNG equilibrium by the early 2020s and an LNG supply-demand gap map develop due to limited supply, justifying the higher price from 2022 to 2030 (Figure C-12).

Figure C-12: Emerging LNG Supply and Demand Gap[12]



[12] Shell LNG Outlook, 2020, https://www.shell.com/promos/overview-shell-lng-2020/_jcr_content.stream/1584588383363/7dbc91b9f9734be8019c850f005542e00cf8ae1e/shell-lng-outlook-2020-march.pdf

C.3.3 Fuel Oil

Oil price forecasts were needed in this project for both providing estimates to fossil fuel generation units burning oil and also as input into the decision for duel-fueled units that can use either natural gas or oil based on price and availability. For this reason, two oil price series were developed for New England:

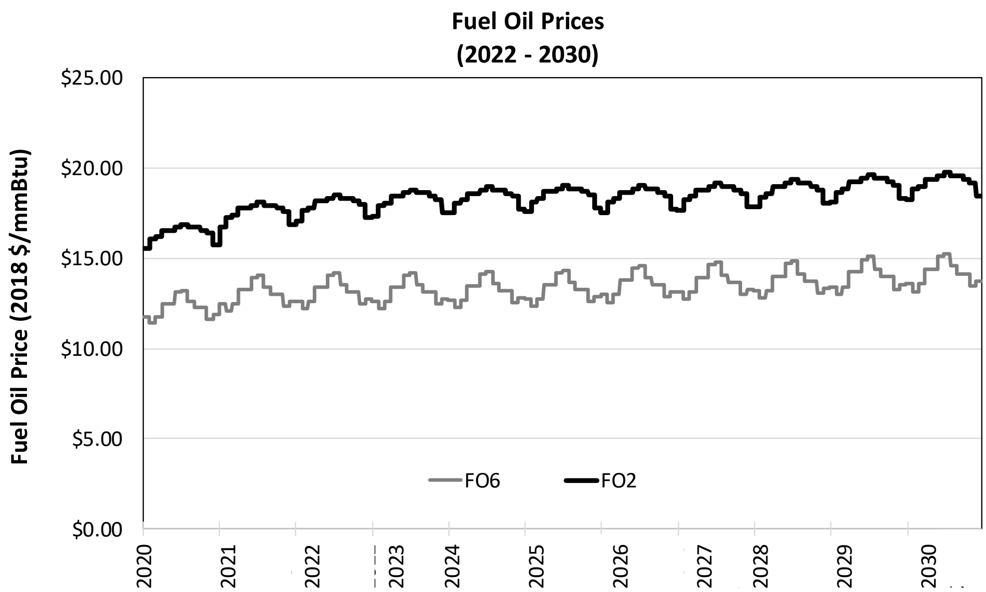
- Light fuel oil was assumed to be #2 distillate fuel oil (the primary petroleum product used in New England)

- Heavy fuel oil was assumed to be #6 residual-fuel oil.

Despite representing only 0.2% of the New England generation mix in 2019, oil plays an important role for grid operations.[13] Units relying on this fuel type often represent peaker plants and other quick start units that provide unique benefits to the grid operator, particularly during times of shortages or high demand spikes. For this reason, it is expected a portion of these plants will remain in operation and therefore pricing must be considered. Energyzt assumed relatively constant monthly fuel oil prices shown in Figure C-13.

[13] ISO-NE Resource Mix, 2019, https://iso-ne.com/about/key-stats/resource-mix

Figure C-13: Assumed Fuel Oil Prices



C.3.4 Coal

For years coal fired generation has been playing less of a role in New England's generation mix, but a few units remain in operation. As of March 2020, New York retired its last coal plant. Coal-fired generation is much more prevalent in the Mid-Continent ISO and PJM Interconnect where they are used for continuous baseload generation, as seasonal peakers and occasional shortage events. Coal prices in each region are based on EIA Annual Energy outlook prices for electricity energy.

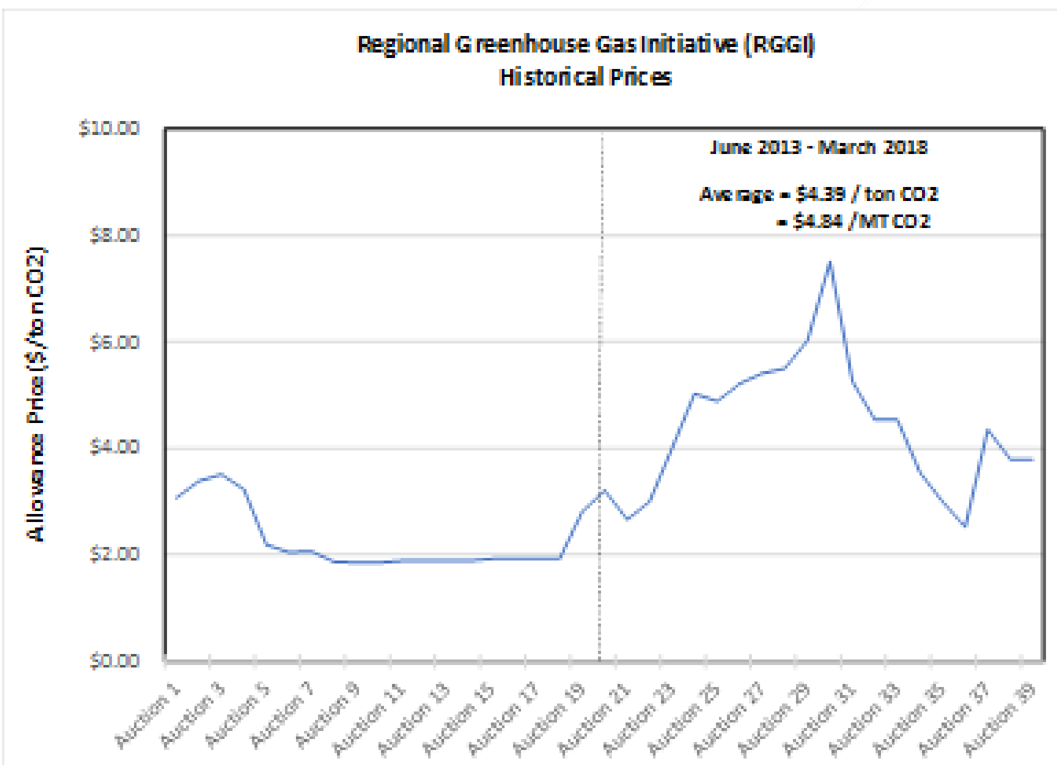
C.5 Emissions Costs

Each coal, gas, and oil-fired unit in the database is set up with an emission rate for NO_X, SO_2, and CO_2 based on the historical emissions from that unit. These emission rates depend on the fuel, the type of unit and any emission control equipment for NO_x or SO_2 that has been fitted. Renewable generation and nuclear units do not have emissions.

The Cross-State Air Pollution Rule (CSAPR) which regulates NO_x and SO_2 emissions from thermal generation does not apply to the ISO-NE market, as the six states in New England were not included in the Rule. However, the prior existing SO_2 (Acid Rain) legislation is still in effect. The SO_2 prices used in the model are very low.

There are currently no Federal regulations that apply to CO_2 emissions. The Regional Greenhouse Gas Initiative ("RGGI") includes all six of the states in the ISO-NE market. The RGGI prices used in the PLEXOS model were based on a combination of historical RGGI prices (Figure C-14) and current Massachusetts policy. As such, carbon prices were assumed to be $5 throughout New England with a $10 adder for Massachusetts from 2022 through 2030.

Figure C-14: Emissions Allowance Price Forecast



C.5. COST BASIS

All cost data – fuel, allowance and unit operating costs - in the PLEXOS simulation is represented as 2018 real dollars. Estimated electricity prices and revenue outputs from the model also are reported in 2018 real dollars.