2021 Economic Study: Future Grid Reliability Study Phase 1

JULY 29, 2022

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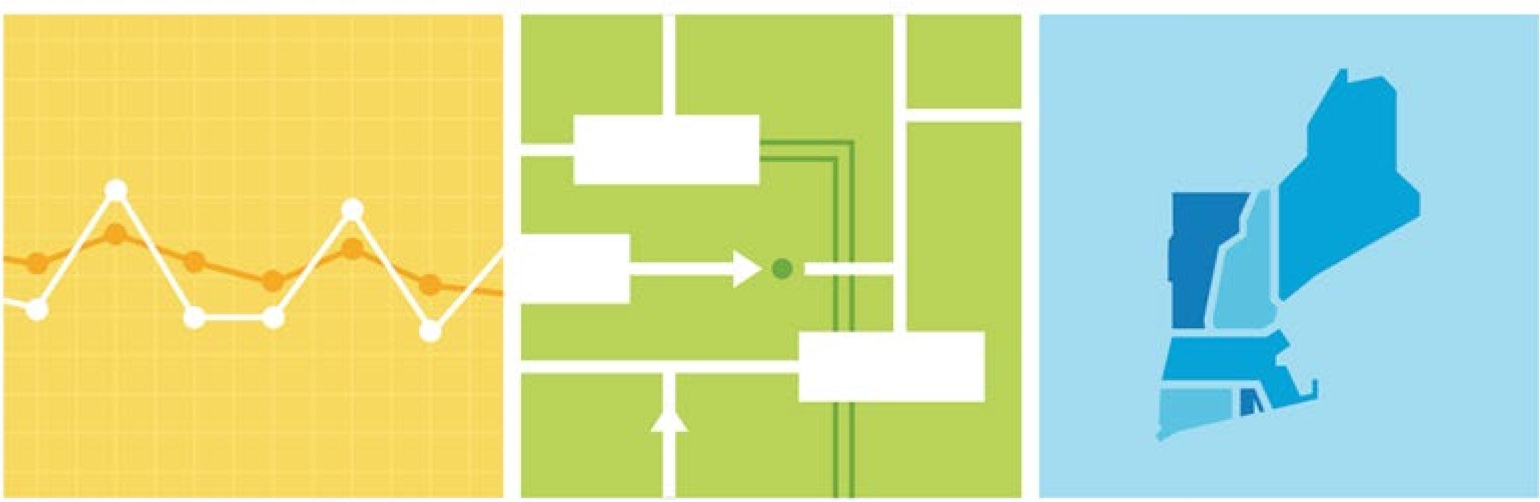

Project Team - Planning Services

Patrick Boughan

Wayne Coste

Steven Judd

Manasa Kotha

Richard Kornitsky

Shahab Rastegar

Marianne Perben

Benjamin Wilson

Peter Wong

Fei Zeng

ISO New England Supporting Groups and Departments

Corporate Communications

Office of External Affairs

Market Development

Load Forecasting

Participant Relations & Services

Transmission Planning

Acknowledgements

Annie Kleeman, Consulting Technical Editor

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Acronyms

BESS – Battery Energy Storage Systems

BTM PV – Behind the Meter Photovoltaic

CELT – Capacity, Energy, Load, and Transmission Report

EE – Energy Efficiency

EIA – U.S. Energy Information Administration

EV – Electric Vehicle

FCA – Forward Capacity Auction

FCM – Forward Capacity Market

FGRS – Future Grid Reliability Study

HQ – Hydro-Québec

HVDC – High Voltage Direct Current

ICR – Installed Capacity Requirement

LFG – Landfill Gas

LMP – Locational Marginal Price

LNG – Liquid Natural Gas

LOLE – Loss of Load Expectation

NECEC – New England Clean Energy Connect

NEPOOL – New England Power Pool

NESCOE – New England States Committee on Electricity

PRAA – Probabilistic Resource Availability Analysis

PV – Photovoltaic

RAS – Resource Adequacy Screen

REC – Renewable Energy Credit

Section 1 : Executive Summary

In recent years, lawmakers across the New England states have enacted ambitious legislation designed to dramatically reduce greenhouse gas emissions over the next several decades. Five of the six New England states have committed to reducing their carbon dioxide emissions by at least 80% in the coming years, which is expected to greatly increase the wind and solar resources supplying electricity to our power grid. Additionally, as electrification of heating and transportation rapidly accelerates, demand on the grid will increase. The path to a carbon-neutral economy must therefore involve larger penetrations of renewable resources.

The power grid relies on *dispatchable* resources to quickly and reliably respond to changes in demand. Traditionally, electricity generated from stored fossil fuels has met much of New England's dispatchable needs. Variable energy resources like renewables are not as inherently dispatchable, and so an overall shift to renewable resources requires strategic forward planning about how to meet the future grid's dispatchable needs.

ISO New England's Future Grid Reliability Study (FGRS), requested by NEPOOL stakeholders, evaluates how a 2040 grid could perform with this shift in both supply resources and increased demand. The study investigates several potential scenarios for a future grid, developed by stakeholders. The resulting analysis produced takeaways in areas that may help inform decision-making as the region moves towards a transformed grid. These takeaways fall under the following categories: **energy adequacy, resource and demand flexibility,** and **resource mix diversity**. They are summarized below and described in greater detail in Section 6 of this report.

Key Takeaways

***Energy Adequacy* is a challenge under the studied scenarios.**

- The future grid scenarios explored in this study may require a significant amount of gas or stored fuels to support variable resources. When coupled with expected demand growth, this may be impossible under current infrastructure. The stored fuels in this future grid do not need to be carbon-emitting, but they must be dispatchable.
- The scenarios contain large amounts of BESS (battery energy storage systems), which may not be able to charge sufficiently under predicted load curves.
- The retirement of the region's nuclear generators assumed in some scenarios may pose a challenge to grid reliability and could thwart the states' goals to reduce carbon dioxide emissions.
- Adding relatively small, targeted amounts of dispatchable units to the most renewable-heavy scenario explored in this study would significantly reduce the necessary new units of wind, solar, and storage, illustrating the importance of dispatchable resources to the future grid.

The need for *Resource and Demand Flexibility* increases under the studied scenarios.

- The variable energy resources in the future grid scenarios lack the controllability and predictability of the region's current dispatchable resources. Increased regulation services may be required.

- Both supply and demand may need to offer more flexibility in order to preserve balance in the system. Demand flexibility could come from solutions like EV Flex, a conceptual idea whereby portions of the region's electric vehicle fleet can be directed to charge at specific times to help flatten overall demand and supply variability.
- Today's resource mix is sufficiently flexible to maintain the balance between supply and demand. With moderate increases in electrification and the retirement of some existing dispatchable resources, the resource mix remains sufficiently flexible. However, with high electrification and more aggressive retirements of the existing flexible fleet, operating reserves may become deficient, and at times completely depleted. Modeling showed that by large margins, available resources were repeatedly unable to match their aggregate output to system demand.

Changing *Resource Mix Diversity* poses new challenges to the grid.

- This study assumes current rules and regulations, which were designed for the existing dispatchable resource mix and summer-peaking grid. As the proportion of variable energy resources increases, and as the grid becomes winter-peaking, these assumptions may need to be refined and remain fluid over the course of the grid's transition.
- The reserve margin – i.e., how many extra resources are needed to keep the system reliable in times of stress – may need to increase by an order of magnitude by 2040 (i.e., from 15% to 300%). A lack of diversity in the future resource mix may necessitate the construction of many more new resources.
- Wind and solar have traditionally made up a small part of overall production, and thus a simplified modeling approach using fixed hourly averages was acceptable practice. As these power sources become predominant, modeling approaches must better reflect the variability of these resources to produce representative results.
- Current models assume summer production levels of select resources, because these resources have lower production capability in the summer. Assuming these lower levels year-round is a conservative way to model the grid. As stress on the grid shifts to the winter, this approach is likely to overstate risk to the system.

Additional takeaways related to the structure of future Economic Studies and software limitations are explored in Section 6.4 of this report.

The Study's Future Grid Scenarios

Several future scenarios were explored as part of the study's assumptions about the future grid. These scenarios assumed **Baseline Decarbonization** (Scenario 0), **Moderate Decarbonization** (Scenario 1), **Import-Supported Decarbonization** (Scenario 2) and **Deep Decarbonization** (Scenario 3). These scenarios are described in further detail in Section 4. Scenarios 0, 1 and 2 all contained moderate amounts of renewables, and also met reliability criteria. Scenarios 0 and 1, however, did not meet state electric sector environmental goals. Scenario 2 met state electric sector environmental goals without reflecting the expected high levels electrification of heating and transportation.

Scenario 3 lowered production costs and met state electric sector environmental goals while supporting high electrification of heating and transportation, but did not meet required reliability criteria. A modified version of Scenario 3, **Resource-Adequate Deep Decarbonization** (Scenario 3

P7), adapted Scenario 3 to meet reliability criteria through a balanced mix of increased wind, solar, and storage (89,900 MW in total wind, solar and storage versus the ~5,600 MW in use today). This scenario would require such a large amount of wind and solar that it may present significant challenges the transmission system and require an outsized amount of land or offshore areas to be sited and developed for the necessary wind and solar farms.

However, as shown in Figure 1-1, the substitution of 3,000 MW of dispatchable units (which could be fulfilled by a variety of potentially emission-free technologies) to Scenario 3 P7 would reduce the necessary new units of wind, solar, and storage by 19% (17,000MW), illustrating the importance of dispatchable resources to the future grid.

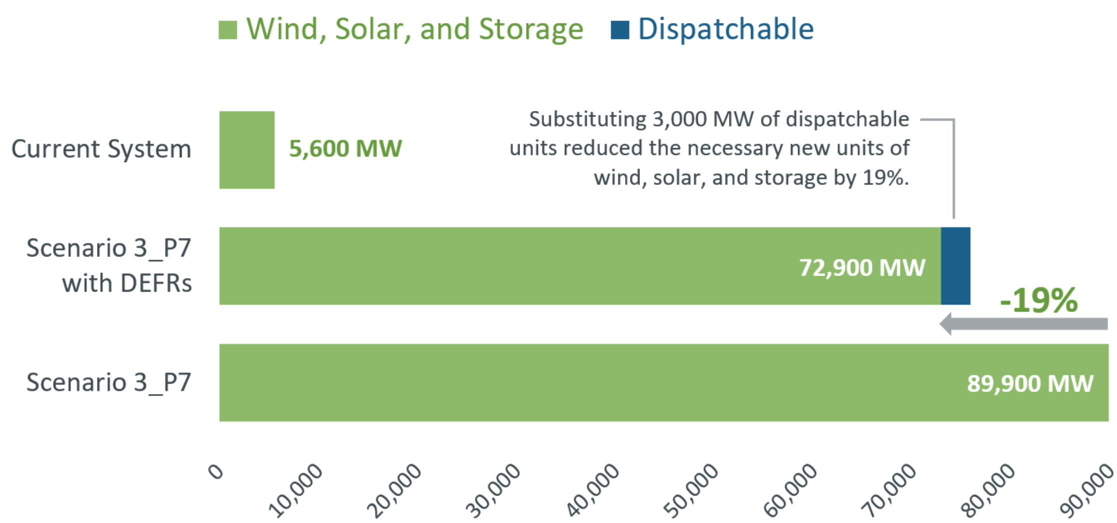

Figure 1-1: Effect of Substitution 3,000 MW of Dispatchable Units to Scenario 3_P7

The FGRS study results show that additional imports or energy banking with Québec are alternatives worth exploring, as these solutions would rely on currently available dispatchable resources and require far fewer transmission interface updates to be successful.

Conclusion

The shift towards a cleaner grid will notably transform the way our region generates, stores, and uses electricity in a relatively short transition period, and as a result, requires continued evaluation of the way we design future grid configurations and evaluate grid reliability. This study identifies what operational and reliability challenges will need to be addressed in the future grid and explores possible ways to meet those needs. The FGRS is a look into how New England might prepare for such a shift in the operation of the bulk power system in order to confront the significant challenges ahead, and to plan practical and innovative pathways forward.

A Note About This Report

Section 2 of this report is designed as a primer for those readers who are less familiar with grid operation, electricity markets, and current state environmental goals related to the energy industry. Readers more familiar with these issues are invited to skip these discussions if desired.

Section 2 : Introduction

2.1 Overview

Climate change presents an unprecedented and complex challenge for our communities and world. As part of wider trends to tackle environmental concerns, lawmakers across the New England states have enacted ambitious legislation designed to dramatically reduce greenhouse gas emissions over the next several decades. In 2021, the New England power grid derived just 12% of electricity from renewable sources. Figure 2-1 shows the change in New England energy resources from 2000 to 2021, and the 2040 resource mix represented in Scenario 3 of this study. The Scenarios are described in further detail in Section 4 of this report. In recent years, however, five of the six New England states have committed to reducing their carbon dioxide emissions by at least 80% relative to mostly 1990 levels in the next 20-30 years, and individual states within the region have set even more ambitious goals for clean energy adoption. These policies will result in major changes in the ways New England sources energy. Throughout the last 30 years, cleaner-burning sources like natural gas have replaced higher carbon-emitting sources like oil and coal. Over the next several decades, renewable sources like wind and solar are expected to substantially displace natural gas.

This significant shift in the ways New England sources energy will be accompanied by changes in the way New England consumers *use* energy. As electricity becomes more prevalent in heating buildings and powering vehicles, demand patterns will evolve. In New England, demand for electricity typically peaks in the summer, with a smaller peak occurring in the winter. However, increased electrification will result in a significant increase in both total demand and peak demand, and push peak demand into the winter months.

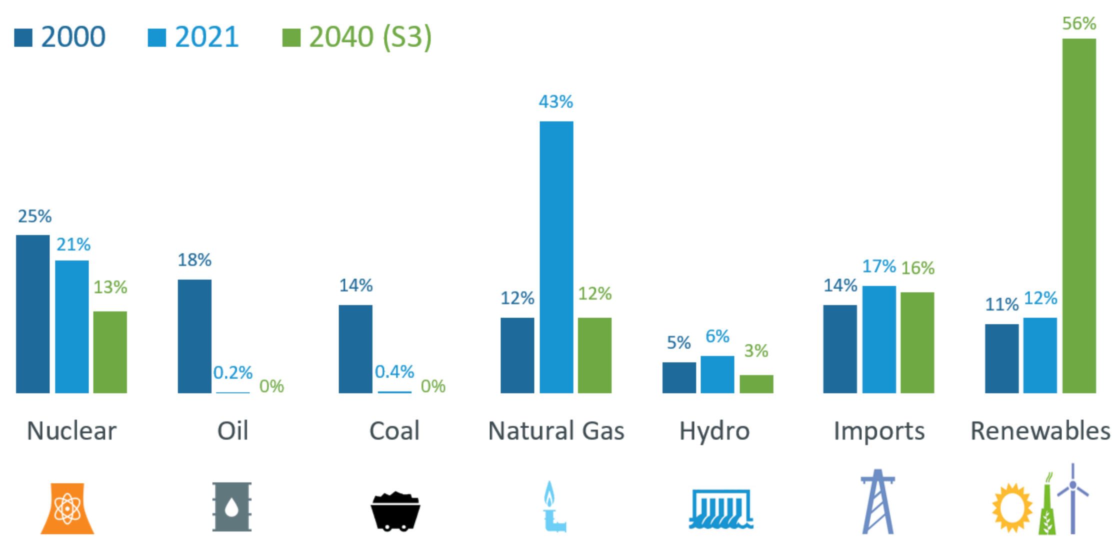

Figure 2-1: Percent of Total System Resources by Fuel Type

The “Transition to Future Grid” Initiative was proposed at the March 2020 NEPOOL Participants Committee. Its objective was to assess and discuss the future state of the regional power system in light of current state energy and environmental policies. NEPOOL requested that ISO New England conduct this analysis.

The resulting study, the Future Grid Reliability Study (FGRS), is an exploration of how our region might confront the significant challenges related to the transformation of our power grid and develop practical and innovative pathways forward. This report details the results and takeaways from the FGRS.

2.2 Assessing the Impacts of a Transformed Future Grid

The New England states have in recent years passed laws mandating that a certain percentage of our future economy's electricity be sourced from renewable resources. The states and other interested parties with a stake in the energy industry seek to transition the electrical grid and the economy to a net-zero carbon dioxide emission paradigm while maintaining grid reliability, keeping costs reasonable, and supporting a healthy economy. The FGRS represents a comprehensive, multi-perspective analysis of how the New England power grid might respond to economy-wide decarbonization. Figure 2-2 illustrates the recent history of carbon dioxide emissions from fossil fuel generators and envisioned emissions from Scenario 3 in 2040.

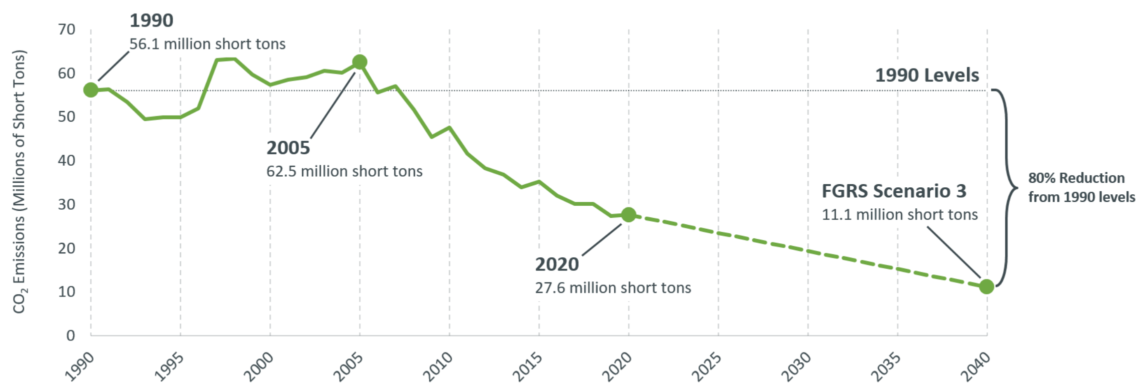

Figure 2-2: Historical and Extrapolated New England CO_2 Emissions (from EIA website)

State policies like the Massachusetts' Global Warming Solutions Act of 2008 (GWSA) and the Resilient Rhode Island Act of 2014 mandate a reduction in greenhouse gas emissions from the energy sector below certain predetermined levels. More recent state laws and policies mandate net-zero emissions by specific years, like 2050. Figure 2-3 overviews New England state policies regarding the electrical sector. This push to eliminate greenhouse gas emissions poses a significant challenge for society, and the accompanying changes to the power grid represent a significant departure from the way the grid has operated since its inception.

The Massachusetts 2050 Decarbonization Roadmap, published in December 2020, explored strategies to help achieve the state's emissions goals, and one modified scenario from that study, Scenario 3 (Deep Decarbonization), was explored in the FGRS.

State Laws Target Deep Reductions in CO_2 Emissions and Increases in Renewable and Clean Energy

≥80% by 2050	Five states mandate greenhouse gas reductions economy wide: MA, CT, ME, RI, and VT (mostly below 1990 levels)
Net-Zero by 2050 80% by 2050	MA emissions requirement MA clean energy standard
90% by 2050	VT renewable energy requirement
100% by 2050 Carbon-Neutral by 2045	ME renewable energy goal ME emissions requirement
100% by 2040	CT zero-carbon electricity requirement
100% by 2030	RI renewable energy requirement

Figure 2-3: New England State Emission Reduction and Energy Decarbonization Goals

For much of the power grid's history, electricity was sourced from fossil-fuels, uranium, or hydropower. In order to meet forecasted demand from residential, commercial, and industrial customers, a certain number of power-generating resources are kept online and operational at any one time. As consumers use more or less power - e.g., as light switches are turned off and on, as heating or cooling systems cycle on and off, and as industrial processes are initiated or completed, operators of the grid provide dispatch instructions to these resources to adjust their output up or down to meet the new demand. Highly responsive resources that can easily adjust their output to fulfill sudden demand changes are referred to as *dispatchable* resources. Traditionally, the grid has relied on dispatchable resources that create electricity from stored carbon-containing fuels, with hydropower being the major exception. Figure 2-4 shows incremental capacity additions to the New England grid over different time periods. 2024's figures are based on 3-year-out Forward Capacity Market results, and the 2025-2040 bar illustrates what additional capacity would be required to meet Scenario 3 assumptions in 2040.

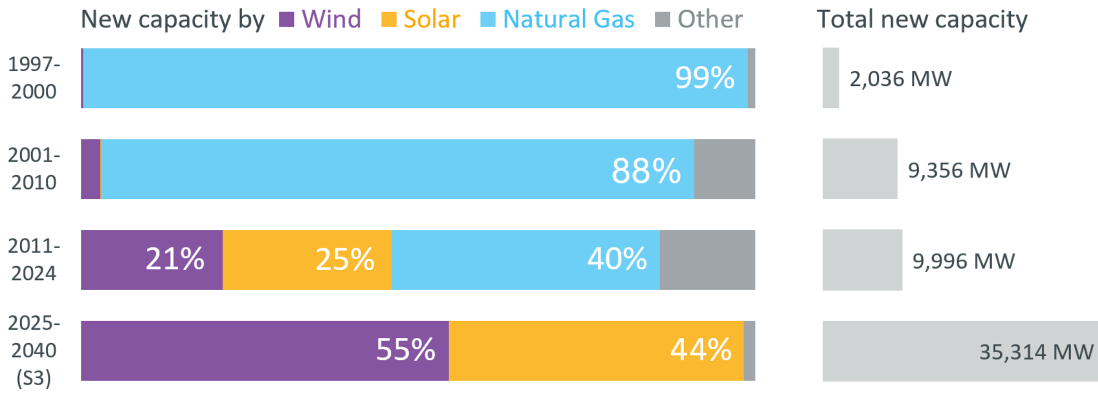

Figure 2-4: Historical and Anticipated New Resource Capacity by Fuel Type, 1997 Baseline

As part of their mandate to reduce emissions, some New England states have directed electrical utilities to acquire more energy from renewable resources. To effect this change, states have signed contracts for the construction of significant high-voltage direct current (HVDC) transmission lines and offshore wind farms, incentives and credits for solar photovoltaic (PV) systems, and provided other direct support to increase renewable electric generation. The federal government's Production Tax Credit and Investment Tax Credit also encourage investments in renewables. These financial incentives significantly impact renewable generation and were reflected in some of the pricing assumptions in the FGRS.

These directives and incentives can encourage consumers and utilities to participate in the decarbonization of the economy. But a significant shift towards these types of resources presents a challenge to the grid's need for *dispatchable* resources. The predicted future shift in resource dispatchability is a major focus of the FGRS. In the current electrical grid, resources such as wind and solar are capable of high output at some moments, but not others. Wind farms generate large amounts of power when the wind is blowing, but zero power when the air is still; solar farms generate large amounts of power when the sun is shining, but generate less power when the sky is cloudy, and zero power when the sky is dark, or panels are covered in snow. As a result, they cannot easily function as *dispatchable* resources - meaning, they cannot be quickly deployed at moments of high demand (a hot summer evening, for example, or an overcast, still day).

These constraints result in highly variable power output from wind and solar resources. Since the variable demand for electrical power does not mirror the variation in output of these resources, a grid-wide shift towards these kinds of resources, as reflected in the FGRS scenarios, can pose significant challenges to maintaining electrical grid reliability. A stable and reliable electrical grid requires a moment-to-moment balance of supply and demand. If supply and demand are significantly unbalanced, the electrical grid will become unstable, and portions of customer demand may need to be disconnected until balance can be re-established. While system operator actions can help mitigate and localize the impact of imbalances with the available margin built into the system in some circumstances, it is ultimately long-range planning's responsibility to create a transmission grid that is reliable. The reliability analysis in the FGRS seeks to assess whether hypothetical future systems have sufficiently diverse resource mixes to support demand from an increasingly electrified economy.

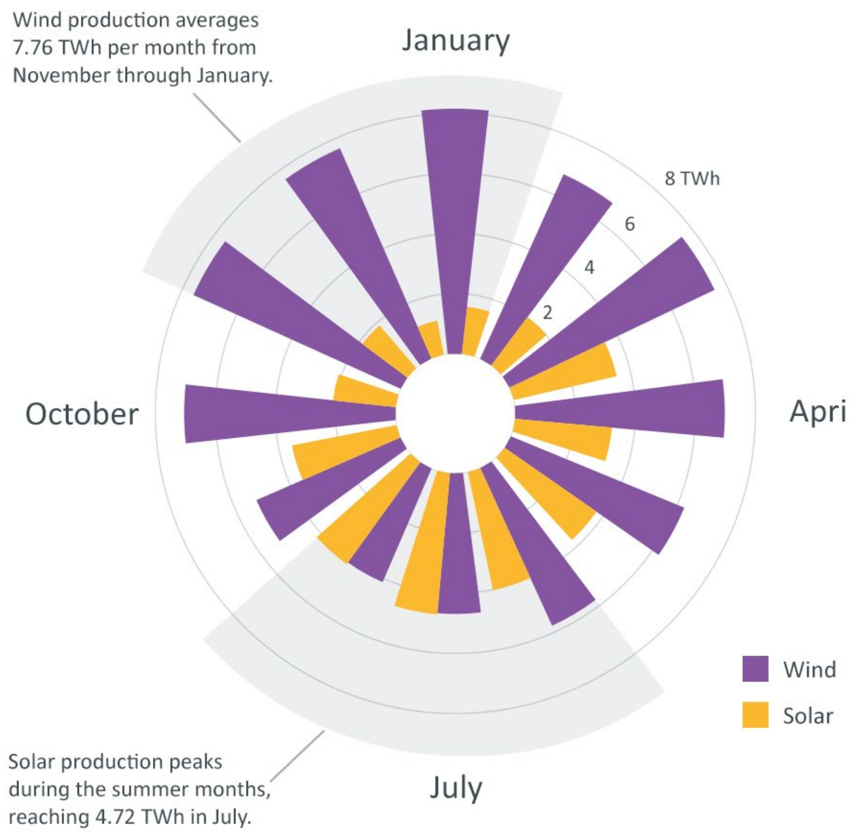

Figure 2-5: Monthly Generation of Variable Energy Resources in Scenario 3 (2040)

Some future grid scenarios explored in this study rely on PV, wind, imports of Canadian hydropower over HVDC tie-lines, and energy storage. These plans include large amounts of already-contracted offshore wind that will be located in federally-controlled waters off the coast of southeast Massachusetts and Rhode Island. These resources all produce energy at different variable energy output levels throughout the year (Figure 2-5). PV has a higher level of output during the summer, spring, and fall, but generally produces less energy during the winter months. The peak output period for offshore wind is winter, with lower production in summer. Onshore wind has a similar output pattern as offshore wind, with less overall output than offshore. All these energy sources have periods of high production and sustained lulls. In the proposed future grid, some combination of energy storage and dispatchable resources will be necessary to maintain adequate levels of production and reliability. Figure 2-6 provides a visualization of the two-dimensional transition the grid might undergo in order to meet carbon dioxide emission goals.

Large quantities of new energy storage, primarily batteries, are often seen as the solution to maintaining grid reliability in a renewable-dominant landscape. For example, on a sunny spring day, solar and wind resources can produce energy at near-maximum output levels. Electrical demand on such a day is relatively low, as cooling and heating needs are minimal. On days of high production and low demand, wholesale energy prices are low. Such days present an opportunity to divert a significant level of output to energy storage for later use. At times of higher demand, when wind and solar output is lower, wholesale energy prices will rise. Previously stored energy could then be discharged into the grid in order to maintain the correct balance of electrical supply and demand.

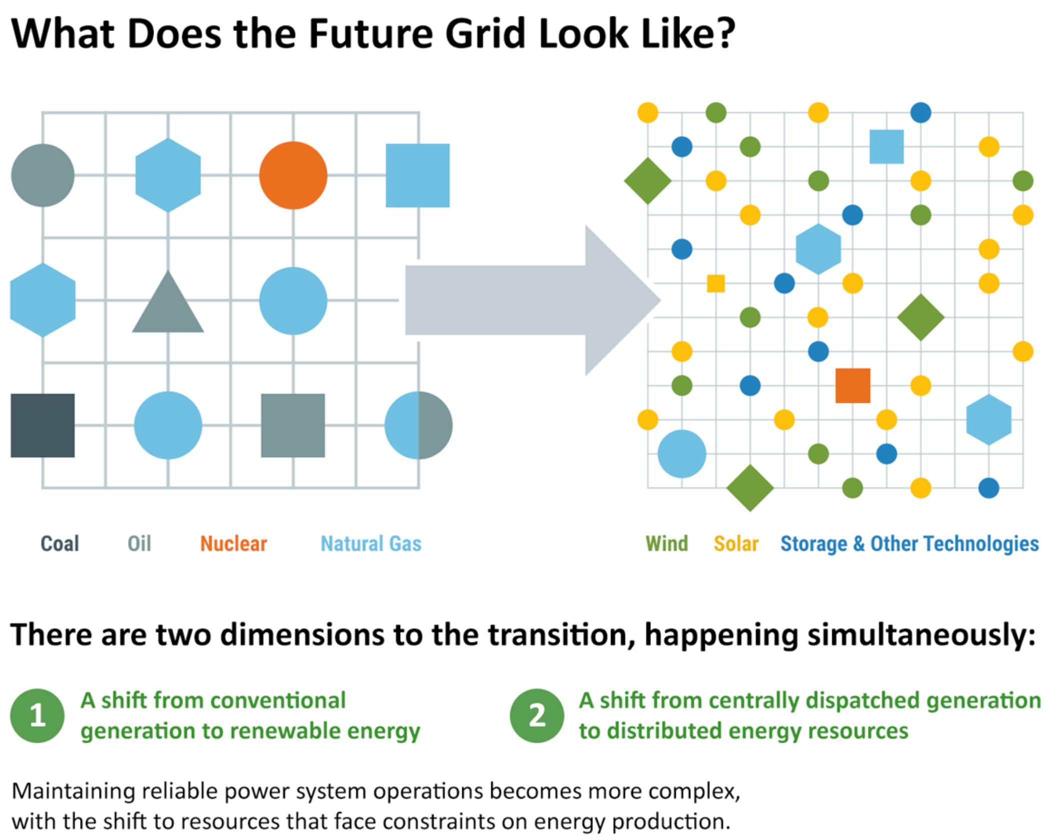

Figure 2-6: Transition to the Future Grid

Other existing energy storage solutions to maintain grid reliability include resources already in service, such as pumped hydroelectric storage. These resources function similarly to battery energy storage systems, in that they store energy when supply exceeds demand for use at a later time. During times of high production, water can be pumped from a lower reservoir or river to an upper reservoir or pond, where it is stored to generate electricity at future periods of higher demand. The potential energy of the stored upstream water is then converted to electrical energy by spinning turbine generators. As part of its many Scenarios, the FGRS explores increasing levels of battery energy storage system penetration on top of the existing pumped hydro energy storage as a way to evaluate storage's role in the grid of tomorrow.

Furthermore, many previous studies, including the FGRS, have assumed existing hydroelectric and nuclear resources will remain in service in the future. These resources can generate electricity without emitting greenhouse gases. Some of these hydroelectric resources are capable of dispatchable production, which could help maintain balance in a more renewable-dominant grid. Wood, biomass, refuse, and landfill gas units could also provide balance in a future grid if they remain in-service. The FGRS also explores Scenarios in which existing nuclear resources are retired, since these resources will be over 50 years old by 2040.

Additional future technologies and increased imports could also help maintain a reliable and economically feasible net-zero carbon emitting power grid. New England's neighbors in New York and bordering Canadian provinces are making similar moves towards a grid dependent on renewables and energy storage. Since weather patterns and storms move through these regions in sequential fashion and have predictable impacts on wind and solar production, a future grid must anticipate that these regions will likely experience sequential peaks and valleys in renewable-based energy production. Increased transfer capabilities between New England and its neighbors could harness the potential benefits of this sequential pattern in mutually beneficial ways, and therefore help mitigate some of the issues inherent in the variability of renewables. New England's current transmission topology and connections to neighboring regions is shown in Figure 2-7.

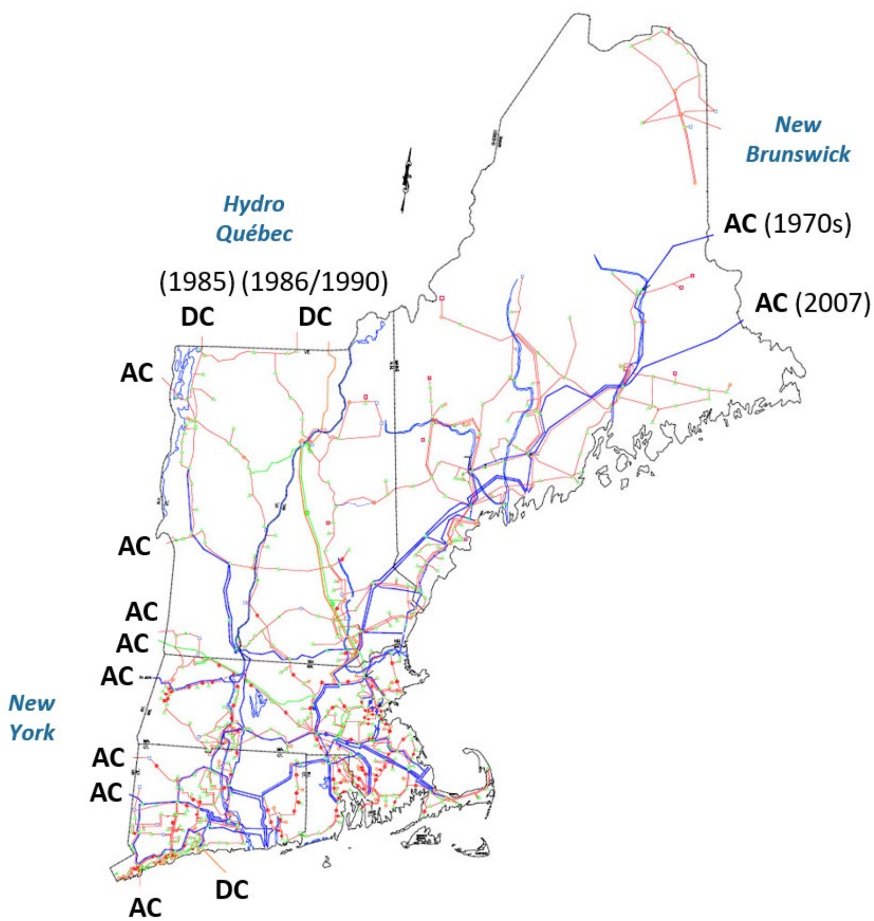

Figure 2-7: Map of New England Ties with External Regions as of 2022 (Map from ISO Website)

A 2020 MIT study highlights the benefits of one possible coordinated regional plan by exploring the possibility of using Canadian hydroelectric power to supplement gaps in dispatchable resources. An alternative Scenario of the FGRS, Alternative A, explores the feasibility of such a plan. Canada currently has an abundance of hydroelectric power, drawn from its large dams in Québec and Maritime Provinces. In most years, these reservoirs store substantial additional energy potential that can be exported for sale to the United States. Existing and additional tie-lines could be supplemented with a more coordinated dispatch between New England, New York State, Québec and the Maritimes to further mitigate the variability of renewable production in the United States. The study also shows the economic benefit of increases in these bidirectional transfers and regional coordination. Specifically, "adding 4 GW of transmission lines between New England and Québec is estimated to lower the costs of a zero-emission power system across New England and Québec by 17-28%."

In addition to the aforementioned changes in electricity supply, regional goals and legislation regarding heating and transportation will also change the way electricity is *used* throughout New England over the next decade and beyond. Heating and transportation will become further electrified. Policy initiatives to replace building heating systems currently powered by wood, oil, propane, or natural gas to electricity will have a significant impact to the power grid. Replacing these building heating systems with electric-powered air-source or ground-source heat pumps will significantly increase the total demand on the New England grid. The replacement of gas and diesel-powered vehicles with electric vehicles will also increase overall system demand. As shown in Figure 2-8, the heating and electrification demand envisioned in Scenario 3 is an exponential increase from current trends. In addition to the overall increase in demand, daily electrical system demand patterns will also change.

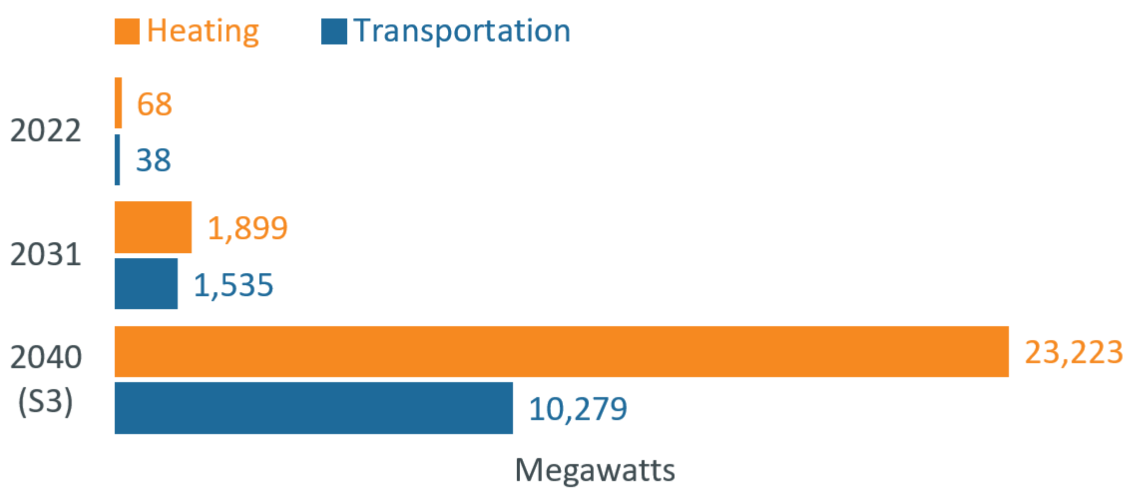

Figure 2-8: Current and Projected Peak Electrification Loads Using CELT Forecast for 2031

Historically, electrical demand increases steadily in the morning as the world wakes up and as heating, cooling and other electric-powered processes turn on. After a period of a few hours, the rate of load (demand) increase typically slows. Load then peaks in the afternoon or early evening before dropping to lows overnight. In today's grid, this pattern has already begun to change - the recent introduction of behind-the-meter PV resources, including the smaller systems installed on the roofs of homes, has altered the shape of the daily load curve. These systems provide electrical energy to individual users and also increase energy supply to the grid in the middle of the day when the sun is shining. The net demand on the larger electrical grid thus falls to nontraditional lows during these hours. The traditional morning pickup in demand is now followed by a new valley in the middle of the day, before a second peak in demand as the sun sets and PV systems produce less power. As shown in **Figure 2-9**, deploying other sufficiently flexible resources to quickly compensate for this second peak can be challenging. The FGRS investigates how the grid might support this. Prior to 2022, there were 35 historical daytime lows *in total* due to BTM PV. In the first four months of 2022 alone, there were 27 daytime lows. In FGRS Scenario 3, the study results anticipate 108 daytime lows for the year 2040.

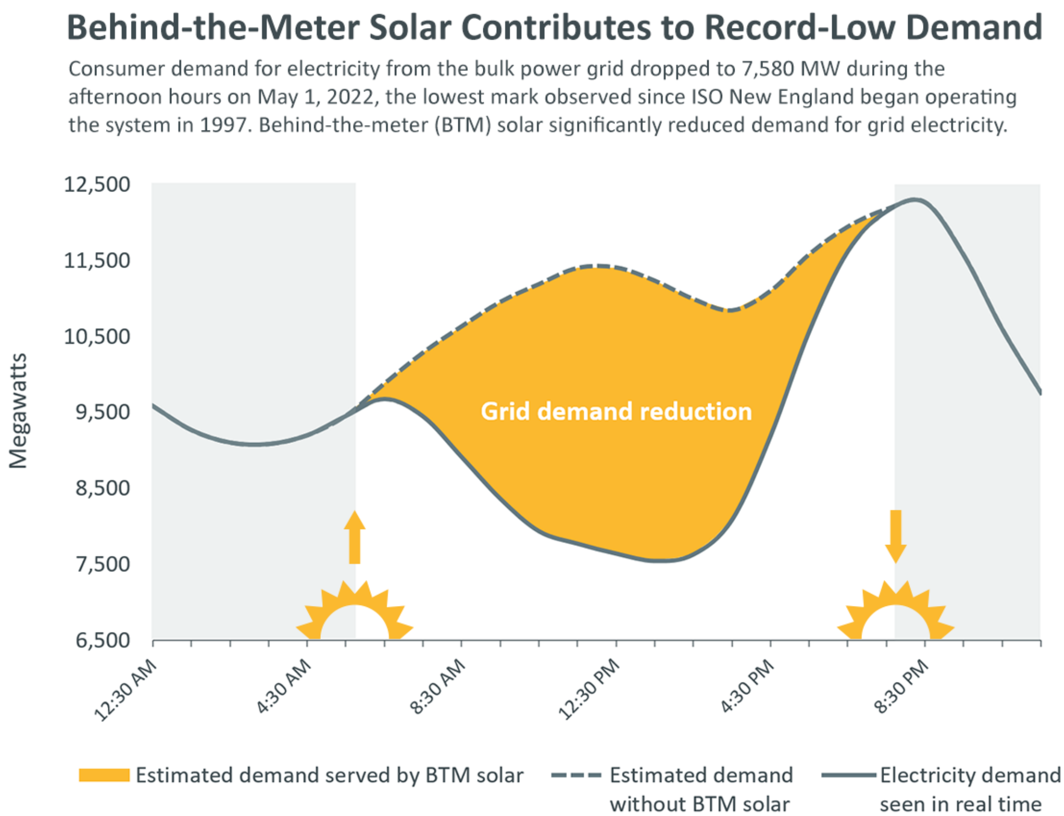

Figure 2-9: Behind-the-Meter Solar Drives Record Daytime Lows in Electricity Demand

In addition to these shifts in daily patterns, the FGRS also explores how *seasonal* electrical demand will be transformed by the expected higher penetration of renewable technologies. In today's electrical grid, peak demand occurs during the summer – driven by heat waves, for example. However, in some future grid Scenarios, summer peaks that would previously be served by dispatchable resources are lowered in part by enormous deployments of PV systems. During the winter months heating electrification can trigger heavier demand in the pre-dawn morning and post-sunset hours, when PV is offline. As a result, future seasonal demand on the electrical grid could peak in winter. Since PV systems produce less on average during winter, the electrical grid will not be able to rely on this large portion of future resources to meet need. At these times, other resources such as wind, storage, imports and dispatchable resources must meet the increased demand. The FGRS evaluates the feasibility of this shift.

2.3 Development & Origin of the FGRS

In order to assess and evaluate this transformed future grid, the "Transition to Future Grid" Initiative was proposed by NEPOOL at the March 2020 NEPOOL Participants Committee. Its objective was to assess and discuss the future state of the regional power system in light of current state energy and environmental policies. Beginning in April 2020 and culminating in March 2021, the joint Markets & Reliability Committees of NEPOOL met to discuss and define a scope of work for the initiative.

NEPOOL proposed conducting this study in two phases. Phase 1 would explore a number of possible future Scenarios, defined by stakeholders, in order to identify the previously mentioned operational and reliability challenges of the future grid. Phase 2 would then consider if the current market structure appears likely to produce the revenues necessary to attract and retain the new and existing resources necessary to continue operating the grid as informed by the stakeholder-defined Scenarios in Phase 1. This report will explore Phase 1 of the study, which ISO performed as part of its responsibilities under Attachment K of its Tariff and NEPOOL's request related to that section. As part of this study, four Scenarios for a future grid, and a set of "sub" scenarios, or Alternatives, were used to represent various possible future grid configurations. These Scenarios will be explained in-depth in a later section. Figure 2-10 provides a graphical overview of the structure of New England's electrical industry.

Who are NEPOOL & NESCOE? NEPOOL is composed of participants in the region's electrical industry, including generators, transmission owners, suppliers, publicly owned entities, end users, and alternative resources. NEPOOL is overseen by the Federal Energy Regulatory Commission, a federal agency that regulates the transmission and wholesale sale of energy in the United States. NEPOOL was initially formed in response to the 1965 Northeast Blackout in order to improve transmission planning, and to promote a more coordinated dispatch of power in the region. NEPOOL works with ISO New England and NESCOE to advise policy around the New England power grid.

NESCOE represents the collective views of the six New England states on regional electricity matters and seeks to advance the states' common views on reliable, economic, and environmentally sound electrical grid operation. As a member of NEPOOL, NESCOE participated in the development and submission of the FGRS.

Who is ISO New England? ISO New England (the ISO) is an independent, not-for-profit corporation responsible for keeping electricity flowing across the six New England states and ensuring the region has reliable, competitively priced wholesale electricity today and in the future. ISO seeks to harness the power of competition and advanced technologies to reliably plan and operate the grid as the region transitions to clean energy. The ISO is authorized by FERC to perform three critical, complex, and interconnected roles for the region spanning Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire, and most of Maine: **grid operation**, **market administration,** and **power system planning**.

Grid operation involves the monitoring, dispatch, and direction of the flow of electricity across the power grid 24 hours a day, 365 days a year. From the ISO's master control center in Holyoke, Massachusetts, system operators help maintain the near-constant balance of supply and demand for electricity required to sustain a stable power grid. Maintaining this balance involves accurately forecasting variables like hourly demand, availability of power resources, and the weather, while accounting for the effects of possible failures of components like generators, transmission lines and circuit breakers. Based on these forecasts, the ISO must then communicate electronic or verbal instructions to start up or shut down power resources, raise or lower output, and carry out other real-time component modifications. Responding to outages on the high-voltage transmission system and generators is also the ISO's responsibility. The analyses performed in this study mimic the way the ISO currently operates the power grid.

Market Administration involves the design, administration, and oversight of the region's competitive wholesale electricity markets. Electricity is a basic necessity, but it is also a commodity - one which is produced, sold, and transported to consumers by for-profit companies and publicly owned entities. The goal of these interrelated wholesale markets is to ensure electricity is constantly available and competitively priced, and the ISO oversees these markets to ensure these goals are met. The structure and assumptions of the FGRS reflect ISO New England market rules as of December 2020, except where otherwise indicated (e.g., a portion of the resource adequacy analysis which was requested by stakeholders).

Power System Planning is the more long-range, comprehensive system analysis and forecasting that is needed to ensure the power grid meets the market's demand for electricity over time. To effectively oversee the movement of high voltage electricity within New England, the ISO must conduct ongoing engineering assessments that estimate the region's power system requirements. Power system planning involves analyzing the grid's requirements up to 10 or more years into the future; ensuring that new resources are properly interconnected; identifying consumption patterns and growth; assessing the adequacy of resources to meet demand, and evaluating issues related to power plant fuel supplies, fuel diversity, environmental requirements, and integration of new technologies. The ISO also responds to stakeholder requests for analysis of various future scenarios, including whether or not increasing certain resources (e.g., renewables) is economically viable. These analyses are known as economic studies; this study falls under that purview.

This planning process is conducted through an open, public forum, and its findings result in the biennial Regional System Plan (RSP), which serves as a comprehensive report on the New England power system.

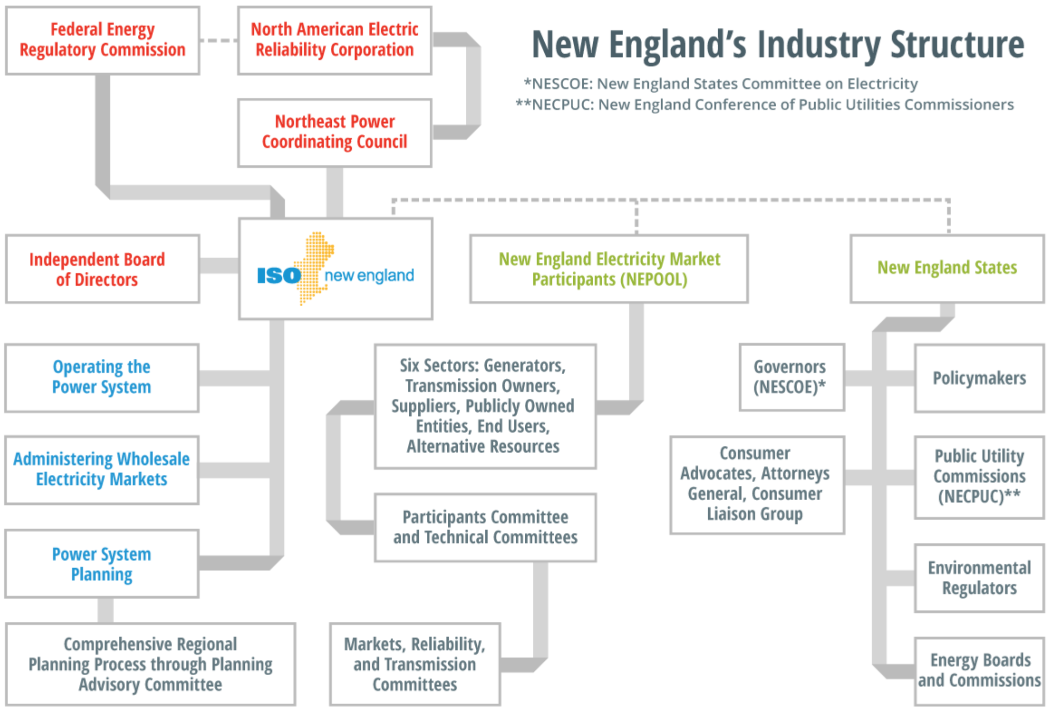

Figure 2-10: Structure of the New England Electric Industry

2.4 An Overview of Wholesale Electricity Markets

In addition to exploring the reliability of a future, renewable-dependent grid, we must also explore whether the future grid will be economically sound, which requires an analysis of how future scenarios might operate under today's wholesale electricity markets. While this is the main focus of Phase 2 of the FGRS, Phase 1 seeks to identify gaps and issues in adapting today's markets and system operations to the future grid.

ISO New England and other FERC-authorized entities nationwide have used electric markets to procure efficient, reliable electricity for over 20 years. Under this paradigm, FERC requires competitive markets to keep costs reasonable while maintaining a reliable system. Under the envisioned future grid, it is expected that ISO New England will continue to oversee markets that generate adequate revenue to attract the investment necessary to reliably operate the grid, much as they do today.

As with most commodity markets, the wholesale electricity markets allow for electricity to be bought, sold, traded, or stored. Storing more traditional commodities like corn and oil is generally easy and relatively cheap. A market trader may wish to wait and sell the corn on a future day when the price is higher, which requires storing the corn for the time being. Some of the Scenarios proposed by the stakeholders in the development of the FGRS involved large increases in storage capacity so that renewable-generated electricity could be consumed when it is most needed. Electricity, however, is not easily stored. While storage technologies have existed for decades (e.g., pumped-hydro storage facilities were introduced in the 1970s), storage technologies continue to evolve and expand. Electricity storage requires significantly more upfront investments compared to other commodities. In addition, a non-trivial portion of electrical energy is "lost" in the process.

The challenges associated with storing electricity present complications in the design and administration of all electricity markets. As the region's independent market administrator, the ISO is required to design markets that are technology-neutral. Electricity markets are intended to protect customers from cost overruns or unexpected expenses related to various technologies. For example, if a given resource provider offers to provide energy at a given price, but the fuel or costs required to provide this resource become more expensive than forecasted, the resource provider should absorb this cost instead of consumers.

In addition to protecting consumers from unjust and unreasonable costs via competitive markets, the ISO must also ensure that there are enough suppliers willing to offer energy to reliably meet customer demand. With insufficient resources, the grid would become unstable, and some retail customers could be cut off from electrical service for a portion of time to save the grid from blackout (a practice known as *load shedding*). The FGRS evaluates if the proposed resource mix is sufficient to serve the expected demand during the entire year.

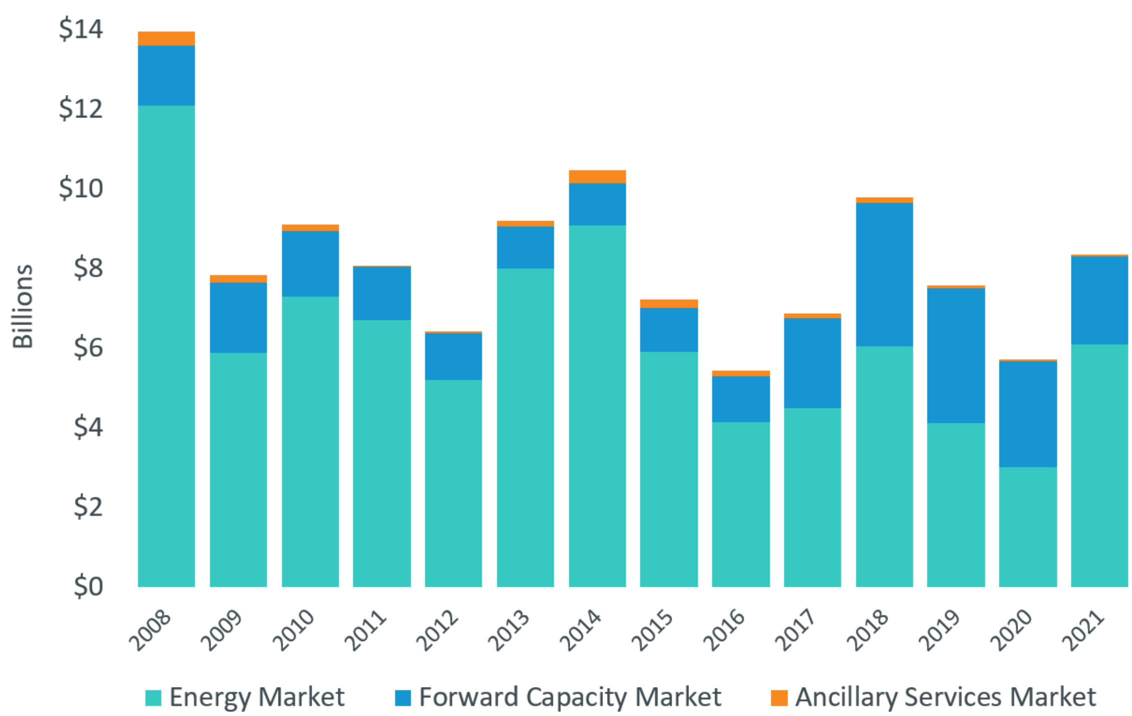

Figure 2-11: Historical Electricity Market Values by Market Type

Electricity markets fall into three main categories – **energy**, **capacity**, and **ancillary services**. Figure 2-11 shows the revenue from each market over the past several years. The energy markets compensate resource providers for power they actually produce, the capacity markets compensate resource providers for committing to produce power in the future, and ancillary services markets compensate resource providers for specific ways in which they produce power that is supplemental to, or in place of, the energy they would want to offer into the energy market. Phase 1 of the FGRS explores ancillary services as they relate to the reliability of the proposed future grid. Phase 2 will explore these areas of the markets in further detail. Except where noted, the FGRS Phase 1 uses the market rules as they were on December 2020 to identify where today's market rules may create challenges or gaps for the future resource mixes envisioned in the FGRS.

Section 3 : Economic Studies

In conducting studies like the FGRS, ISO New England provides the region with information and data on possible evolutionary changes to the power grid. Changes to the grid impact us all, and the implications of these changes must be explored and shared widely in order to educate and inform. Since the ISO is a regional transmission operator, it possesses market sensitive information about system resources and critical energy infrastructure information (CEII) about the power system that cannot be shared broadly. However, the ISO can use this unique access to data to produce publicly available studies to inform future development.

As noted, the ISO is authorized by the FERC to act as an independent planner and operator of the region's electrical grid and administrator of wholesale electricity markets. The governing document of the ISO is called the *ISO New England Inc. Transmission, Markets and Services Tariff* (Tariff), and any changes to the Tariff must be approved by the FERC. Attachment K of the Tariff authorizes the ISO to conduct needs assessments as they relate to the Regional System Planning (RSP) process. Attachment K also allows stakeholders (like NEPOOL and the New England States) to request these needs assessments for economic consideration on an annual basis in order to evaluate changes to the power grid that might reduce total production costs or reduce congestion on transmission lines. These types of needs assessment are also known as economic studies. The FGRS is the 2021 economic study. Other needs assessments performed by the ISO evaluate critical reliability aspects of the grid, such as the ability to serve load and remain compliant with national and regional standards and criteria.

3.1 History and Use

Since 2008, the ISO has performed a variety of economic studies. These studies have considered a wide range of topics but often focus on potential changes to the power grid related to the region's environmental goals. Some economic studies have been very narrow in scope (e.g., 2019 Orrington South Study), and some very broad (e.g., 2016 Study and 2021 FGRS).

The hypothetical alternative systems explored in economic studies should not be regarded as physically achievable plans or as ISO's vision of realistic future development and preferences. However, they can assist stakeholders in their decision-making by identifying key regional issues.

Generally, economic studies explore hypothetical future systems that deviate from today's electrical grid in large and small ways. These deviations can include changes to how the system operates, new transmission lines, new technologies, and the retirement of existing resources. To date, the ISO's economic studies have been focused heavily on the integration of wind and solar power or increased transfers with our neighboring systems. These studies also assume the substantial conversion to electric vehicles and air-source heat pumps mentioned in previous sections. Based on evolving perspectives and state legislated goals, what was considered an aggressive case Scenario five or more years ago might be a conservative case Scenario today.

3.2 Improving Predictability Using Recent Advances in Modeling Tools

The grid analysis and evaluation in the FGRS was conducted using more advanced modeling tools than prior studies. The FGRS is a further evolution of the ISO's economic studies using more types of analyses to bring clarity to the future grid.

Historically, economic studies have relied on production cost analysis tools only. These tools approximate how the electrical grid is operated today, and with simplifications that can approximate how the grid might operate in the future with a different mix of resources and demand patterns. Production cost analysis allows us to estimate the costs, emissions, and function of hypothetical future power grids, but cannot by itself ensure that the system will be reliable. This is because the goal of production cost analysis is to evaluate expected high-level outcomes without a focus on the specialized, time-scale sensitive task of reliability analysis.

Over time, the ISO has responded to new and different questions about the future grid from stakeholders by adding additional types of analyses. In the 2016 Study, for example, the ISO explored a potential change in ancillary services by collaborating with an external consultant to adapt their program to mimic the ISO's market system. In previous, production cost analysis-centric studies of ancillary services, the ISO modeled the system on an hourly basis. In contrast, this tool modeled the system on a minute-by-minute basis. This tool was also used in the FGRS.

This increased specificity in timescale can be extremely useful. While some aspects of the power system can be usefully studied on an hourly basis, ten or fifteen-minute time windows are more useful for other analyses, and time windows of mere seconds are more useful for still others. Using a model that relies on hourly time windows will likely miss the problems that ancillary services must solve. For example, in a certain Scenario, wind production might provide ~500 MW of electricity at 5:00 PM, drop down to 100 MW between 5:25 PM and 5:30 PM, and then recover to 500 MW by 6:00 PM. The entire problem that an economic study seeks to explore and solve would occur and resolve within one hour, and thus be missed entirely by existing models. This type of analysis requires modeling that can capture smaller time increments.

3.3 Advances in Transmission, Bidirectional Exchange & Resource Adequacy Analyses

The 2016 Economic Study and 2019 Offshore Wind Integration Economic Study modeled the impact of high-level transmission upgrades. These studies looked at both constrained or unconstrained limits on power flows and gave estimates about what interface-level upgrades would be needed to significantly reduce costs related to congestion. In its own exploration of transmission upgrades, the FGRS produced similar results to these two prior studies but did not include the approximate cost of the upgrades. Though high-level in nature, these results provide actionable data for stakeholders as higher penetrations of wind and solar resources become standard in the New England grid. This high-level analysis flags these areas for more granular future analyses.

The 2020 Economic Study explicitly modeled a bidirectional exchange of electricity with our neighbors for the first time and examined the potential impact of more inter-regional cooperation and power sharing with New York, Québec, and the Maritimes. Previous economic studies used historical data to model imports and assumed an import-only representation. In these models, the New England grid received electricity from our neighbors, but did not export electricity in the opposite direction. Based on historical profiles, the 2020 study's bidirectional model allowed for imports that would be curtailed based on a threshold locational marginal price (LMP), and then begin to export energy out of New England once those LMPs reached an even lower threshold price. This model explored the possibility of exporting wind and solar energy that in previous economic studies' Scenarios would simply have been curtailed. A further extension of this bidirectional model was used to create an energy-banking model that would eventually be used in the FGRS's Alternative A. The energy-banking model operated similarly to the bidirectional model but was designed so that all energy sent to Québec by the bidirectional model plus the energy that could not be taken from scheduled imports was stored and then used at a later time to displace a carbon-emitting fossil generator. In simpler terms, this meant that by the end of the simulation year, every MWh sent to our neighbors in Québec would be returned to New England over the course of that year. Both the bidirectional model and energy-banking model allowed for the investigation of long-term storage with our neighbors in Hydro-Québec to minimize curtailment of wind and solar energy and to maximize the production possibilities of those resources, which would result in lowering dependence on carbon-emitting resources across the region.

> Under an **energy banking scenario** involving Québec, Hydro Québec (HQ) would curtail hydro energy production during periods when they were accepting energy from the New England grid. During times of high production, HQ would then export energy to New England.

In addition to the previously mentioned tool the ISO now uses for modeling ancillary services, the FGRS implemented a resource adequacy reliability analysis using the tool that determines the ISO's installed capacity requirement. In traditional economic studies, stakeholders provide the ISO with assumptions about resource mix and load that are then run through production cost analysis and more recently ancillary service analysis. While useful for exploring certain aspects of reliability such as unserved energy under expected or normal conditions, these types of analysis are not designed for resource adequacy (RA) analysis. RA analysis provides for a better understanding of an assumed resource mix and load by calculating whether a theoretical system meets reliability criteria used in today's grid. RA analysis can simulate thousands of versions of a particular year, which significantly improves the ability to predict risk in the future.

The work of FGRS showed that the results from one type of analyses could inform the inputs to other types of analyses. In the FGRS, a variety of modeling and analysis types were utilized iteratively to get the most meaningful combination of economic and engineering analyses. These analyses were used to explore what conditions will likely present operational or reliability issues under the future Scenarios. Specifically, once FGRS identified a shortfall of units in the RA analysis, it re-simulated other portions of the analyses with sufficient supply resources to meet RA criteria.

3.4 Concurrent & Related Studies

The FGRS is one of three significant studies that the ISO has recently undertaken to better understand the needs of a future New England grid. In addition to the FGRS, the ISO recently completed the Pathways Study and is currently performing the 2050 Transmission Study. While these studies are distinct from the FGRS, certain aspects of the FGRS relate to analyses in both the Pathways and the 2050 Transmission studies.

The Pathways Study evaluates various approaches to achieving the states' emission reduction targets. Rather than beginning with an assumed resource mix, the model solves for the economic resource mix in 2040 under four different policy approaches. The Status Quo Scenario from the Pathways Study informed some of the reliability analysis work in the FGRS. By using the Status Quo resource mix of the Pathways Study in the FGRS analyses, the ISO was able to add further context for how the Status Quo Scenario might perform in a future system.

The 2050 Transmission Study seeks to identify high-level transmission roadmaps to serve future load while satisfying various reliability criteria. This study is based on similar assumptions as FGRS Scenario 3, which used the Massachusetts 2050 Deep Decarbonization Roadmap Study's "All Options Pathway" as a base assumption. This detailed transmission analysis provides additional insight into some of the future systems explored by the FGRS.

Section 4 : Scenarios and Alternatives

The final set of Scenarios explored in the FGRS included 32 alternatives, each exploring a different set of assumptions. Though none of these Scenarios should be interpreted as a forecast of a future grid, trends and relationships between Scenarios can provide an idea of how different assumptions will affect the operation of a future grid.

Table 4.1: Load and Resource Matrix for Scenarios studied in the FGRS

	(Resource 0) OFSW ~3,100 MW PV 14,444 MW BESS**: ~600 MW	(Resource 1) OFSW 8,000 MW PV 16,000 MW BESS 2,000 MW	(Resource 2) OFSW 8,000 MW PV 22,000 MW BESS 3,940 MW	(Resource 3) OFSW 17,000 MW PV 28,000 MW BESS 600 MW
(Load 0) Buildings: CELT* Transport: CELT*	**Scenario 0** Baseline Decarbonization			
(Load 1) Buildings 9,600 GWh Transport 7,300 GWh		**Scenario 1** Moderate Decarbonization		
(Load 2) Buildings 6,600 GWh Transport 18,500 GWh			**Scenario 2** Import-Supported Decarbonization	
(Load 3) Buildings 38,900 GWh Transport 40,000 GWh				**Scenario 3** Deep Decarbonization

*CELT: 7,550 GWh building load and 10,500 GWh transportation load included in CELT gross load. Other scenarios add additional electrified load onto the CELT gross load.

** BESS: Battery Energy Storage Systems

4.1 Main Scenarios

The FGRS explored four different Scenarios that modeled the future New England grid, shown in Table 4.1. Each Scenario represented a different view of the future grid, with different assumptions about generator retirements, wind and solar additions, new transmission lines, and other properties. These Scenarios were numbered zero through three.

4.1.1 Scenario 0 (Baseline Decarbonization)

Scenario 0 is also referred to as the reference case. It is a projected version of the current system in the year 2040, assuming current growth trends based on the 2021 Capacity, Energy, Loads, and Transmission (CELT) Report. Scenario 0 consisted of extensions of the current ISO trends and forecasts for various resources, with generator retirements and additions through Forward Capacity Auction (FCA) 15 - the ISO's three-year-out capacity market. Scenario 0 also included the ~3.3 GW (note all values given are nameplate values) of offshore wind farms with state contracts at the end of 2020 and the contracted New England Clean Energy Connect (NECEC) tie-line. Scenario 0 did not include any additional heating or transport electrification beyond extrapolating current ISO electrification forecasts to 2040. The heating load in this Scenario represented 4.9% of the total load energy, while the transportation demand represented 6.8% of the total. Other Scenarios included additional heating and transportation demand on top of the CELT load. Overall, Scenario 0 was the most similar to the current day ISO system, with the lowest penetrations of wind and solar, minimal retirement of generators, and the conservative adoption of heating and transport electrification.

4.1.2 Scenario 1 (Moderate Decarbonization)

Scenario 1 assumptions were derived from the 2020 Economic Study requested by National Grid. That 2020 Economic Study built upon a 2019 Economic Study request by NESCOE. Scenario 1 modeled a moderate penetration of renewable energy, with moderate heating and transport electrification. Scenario 1 assumed the retirement of all generators that have announced a planned retirement, along with all remaining coal units and 75% of the remaining oil units. To compensate for these retirements, Scenario 1 added 8 GW of offshore wind, 2 GW of BESS units, and the NECEC tie-line. The Scenario assumed an increase in the total solar nameplate capacity to 15.8 GW. Additional heating and transportation load comprised 5.8% and 4.4% of the total load. Scenario 1 utilized an import-priority threshold price order, where wind and utility solar resources were curtailed before tie-line imports.

4.1.3 Scenario 2 (Import-Supported Decarbonization)

Scenario 2 assumptions were derived from Eversource's (unreleased) Grid of the Future Study. Scenario 2 assumed similar properties to Scenario 1, but with a number of adjustments. Scenario 2 retired 8.4 GW of fossil fuel units, including all remaining coal and oil. For additional resources, Scenario 2 added 8 GW of offshore wind, 4 GW of BESS units, the NECEC tie-line, plus a new 1 GW tie-line with Hydro Québec. Total solar nameplate was increased to 20.3 GW. More emphasis was placed on the electrified transportation load than the electrified heating load, with 3.3% of the total load coming from additional electrified heating and 10.8% of the total load coming from additional transportation electrification. Instead of import-priority, a REC-inspired (renewable energy credit – an outside electric market payment certain clean resources can earn) threshold order was used where tie-lines were curtailed before wind and solar resources.

4.1.4 Scenario 3 (Deep Decarbonization)

Scenario 3 assumptions were derived from the "All Options Pathway" of the Massachusetts 2050 Deep Decarbonization Roadmap Study and imagined heavy renewable penetration and electrification loads. Scenario 3 modeled all retirements through FCA 15 plus all remaining coal, oil, and refuse-burning plants. Renewable additions were large, with 16 GW of offshore wind (a doubling from Scenario 2), 28 GW of solar nameplate (a 38% increase from Scenario 2), 600 MW of BESS, the NECEC tie-line, plus an additional new tie-line with Hydro Québec. Both heating and transportation electrification load additions were large, with the heating load comprising 20% of the total load and transportation comprising 18.6%. While all other Scenarios only modeled importing transmission lines, Scenario 3 assumed bidirectional lines, allowing New England to export power to New York, New Brunswick, and Québec after curtailing import power. The threshold order in Scenario 3 would curtail renewables only after exporting. Finally, Scenario 3 introduced interchange with New York, while other Scenarios only had imports from Québec and New Brunswick. New York flows were not modeled in Scenario 0, 1, and 2, or in previous studies. In prior studies, this was to avoid "relying" on New York to serve New England's load. The Massachusetts 2050 Deep Decarbonization study assumed an increase in interconnections in the northeast United States and, notably, between New England and New York. The results of that study showed significant interchange between New England and New York that was driven by additional paths to the energy storage resources in the Québec reservoirs. This meant that energy could flow from New England to Québec via New York and also into New England from Québec across the New York system.

4.2 Alternative Scenarios

In addition to the main Scenarios, there were several alternative "sub" Scenarios applied to some or all of the main Scenarios. Table 4.2 overviews the alternatives and which main scenarios they were applied to. These alternatives reflect additional assumption changes to the main Scenarios and were then compared to the base Scenario to see the effects of those changes. The alternative Scenarios were named A-G, which were then applied to Scenarios 1, 2, and 3 unless otherwise noted below. After running each alternative, the output metrics were compared to the base Scenario to determine the effects of the changes in assumptions.

4.2.1 Alternative A

Alternative A added an unconstrained bi-directional high-voltage direct current (HVDC) tie-line from Québec to Northeast Massachusetts (NEMA), and Québec hydro reservoirs were available for use to function as long-term energy storage. To avoid curtailment, surplus renewable energy could be exported out of New England and reimported later to displace fossil-fuel generation. Threshold prices were defined for export energy to model the new storage opportunity. The purpose of modeling this new tie-line and storage was to decrease curtailment of renewable resources and displace fossil fuel generation with the reimported energy. Alternative A explored the benefits of increased and bi-directional interregional power exchange between New England and Québec.

4.2.2 Alternative B

Alternative B explored utilizing a portion (25%) of 8 million electric vehicle batteries as vehicle-to-grid storage, also called EV Flex. This concept allows vehicles to both charge and discharge to the grid, rather than only charge. The EVs in this alternative were distributed throughout New England proportional to existing load distributions. The EV batteries would provide price arbitrage to compensate the owners for the increased battery cycling. It was theorized that these batteries would help reduce renewable curtailment and displace fossil fuel generation. Alternative B was only applied to Scenario 3.

4.2.3 Alternative C

Alternative C retired all remaining nuclear generation in New England, removing ~3.4 GW of high capacity factor carbon-free capacity. New England depends on a relatively small number of nuclear generators for a large portion of its energy. Nuclear energy is used as base generation, meaning it provides a steady amount of energy throughout the day and throughout the year. As of today, each unit of the New England nuclear fleet has been in service for between 35 and 50 years and each of these units will someday retire. Alternative C was identified to show what the New England grid would look like without these resources.

4.2.4 Alternatives D & E

Alternative D retired all fossil fuel generation and added significant amounts of wind, solar, and BESS units. The resulting grid was a carbon neutral system, with only nuclear and hydro units remaining from the old fleet. The Alternative D fleet reflected the goal of full decarbonization, as there would be no emissions in this alternative Scenario. Alternative E had the same assumptions as Alternative D, except the offshore wind interconnection points were redistributed to reflect theoretical offshore grids. Connecting significant amounts of offshore wind using only Southeast Massachusetts (SEMA), CT, and RI as interconnection points is expected to cause major congestion. This scenario's objective was to analyze different impacts of onshore and offshore grids by bypassing existing constraints of the onshore grid to deliver the offshore wind to load centers as suggested in the 2020 Brattle/GE/CHA study. Alternative E was only applied to Scenario 3.

4.2.5 Alternative F

Alternative F changed the threshold prices to the 'import-priority' order. It is uncertain how future REC prices will affect the order in which resources are more and less economical to run. Significant penetrations of wind and solar will result in periods of oversupply, and the dynamics of RECs will determine which resources can afford to continue operations when LMPs become negative. Scenario 1's assumption of import priority prices may reflect how the future system operates, but the likelihood of this eventuating is unclear. Modeling both methods of priority price orders gives stakeholders an idea of what LMPs and curtailment figures would look like under both possible Scenarios. Alternative F was only applied to Scenario 2 and Scenario 3 and reintroduced the import priority threshold order on a Scenario 2 and Scenario 3 system.

4.2.6 Alternative G

Alternative G disabled all tie-lines with New York. Using historical flows with New York may not accurately portray a future grid. For example, if New England has a significant excess of solar power in the middle of the day, New York will likely be experiencing similar conditions. Using historical flow assumptions could model New England's grid as having sufficient power to meet demand when this power may not be available in 2040 at the times it was in past years. Alternative G was designed to isolate the impact of the New York flow assumption on the results. Alternative G was only applied to Scenario 3.

4.2.7 Additional Scenarios

The main Scenarios assumed that the pace of electrified load increase and renewable energy development would be comparable. Two additional Scenarios explored what might happen if one outpaced the other. Scenario 2, load 3, resource 2 (S2_L3R2) mixed and matched assumptions from different Scenarios, taking the Scenario 3 EV and heating loads and placing them into a Scenario 2 case. The resulting Scenario had high electrification loads with moderate penetrations of renewables. Another Scenario, Scenario 2, load 2, resource 3 (S2_L2R3) took the Scenario 2 assumptions and replaced the wind, solar, BESS, and generator retirement assumptions with Scenario 3 levels. The resulting model had high penetrations of renewable resources with only moderate electrified loads.

These cases were meant to show the effects of uneven advancements in decarbonization, as it is unclear whether New England will maintain a balance between development of both electrified heat and transportation and renewable resources.

Table 4.2: Application of Alternative Scenarios to Main Scenarios

Alt	Description	S1	S2	S3
A	Energy Banking with Canada	X	X	X
B	Vehicle-to-Grid			X
C	Nuclear Retirements	X	X	X
D	100% Carbon-free Energy	X	X	X
E	Alt. D with Offshore Grid	X	X	X
F	Curtailment Priority Order		X	X
G	No NY Interchange			X

Section 5 : Analyses and Observations

The following section explores the production cost analyses of the FGRS. Production cost models simulate how generators dispatch to serve load with a goal of minimizing production costs. This objective maximizes social surplus within the wholesale electricity markets which reduces costs to customers and maximizes profits to generators in the energy market to the extent possible given the cost minimization goal.

5.1 Production Cost

The FGRS Phase 1 modeled the real-time energy markets at hourly increments for the study year of 2040 using a production cost model. Production cost models require a vast amount of input data ranging from system topology to individual generator's operating characteristics. Characteristics of each generator and various load shapes are accounted for such that the New England system is represented in reasonable detail. For each hour of the study year, the model looked at the requirements of the load within the next 24 hours to 7 days and committed units to minimize production costs. By modeling energy costs, a key component of wholesale costs can be developed for comparative purposes.

Constraints to the system like transmission interface limits may be modeled in production cost analysis, but for the purposes of this study, transmission interface constraints were modeled as a separate set of sensitivity analyses to show the effects of transmission congestion on select Scenarios.

Results of these simulations included information about the utilization of each generator, curtailment of renewables, emissions, and more. These results can be used to benchmark against the current-day system as well as alternative future systems. These results can then explore the advantages and challenges of various grid configurations while accounting for cost and total emissions. While not a perfect model for predicting how a future system will operate, production cost models can provide insights into theoretical resource mixes that can help shape the path to a decarbonized grid.

Production cost results – particularly in Scenario 3 – revealed a system that struggled to provide the operational flexibility needed to serve this future load. Results further revealed that the system relied on stored energy in existing gas pipeline infrastructure, LNG storage, and assumed future storage of renewable energy in order to meet demand during peak winter heating conditions. Figure 5-1 shows a January 2040 daily natural gas consumption vs projected pipeline gas and LNG imports available to electric generation based on the ISO 2025 Gas availability forecast, illustrating frequency of days when the system is unreliable

Electric distribution utilities or suppliers buy electrical energy wholesale on the market and sell it to retail customers in homes and businesses. New England has two overlapping electric **energy services** markets: Day-Ahead Energy Market and Real-Time Energy Market. The Day-Ahead Energy Market allows suppliers to secure prices for electric energy the day before delivery as a hedge against price fluctuations. The Real-Time Energy Market balances the dispatch of generation and demand resources to meet the instantaneous demand for electricity throughout New England. The Real-Time prices differ from the Day Ahead Energy Market due to real-time variations in supply and demand, but the markets prices generally converge. The production cost results from this study give information about a competitive future grid given the structure of today's day-ahead energy markets.

under FGRS Scenario 3. Though today's system is reliant on natural gas and LNG delivery, a future system may instead utilize a renewable fuel that could take advantage of existing pipeline infrastructure to replace natural gas or LNG. Pipelines are simply a means of delivering energy and could be retrofitted for use in the future to deliver low or zero-net carbon gaseous fuels. Developments in energy storage might also provide needed flexibility.

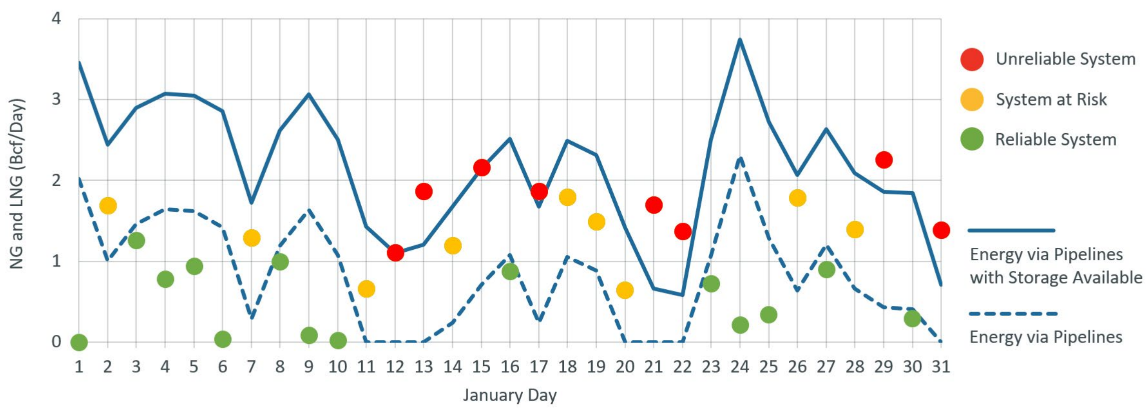

Figure 5-1: January 2040 Daily Natural Gas Consumption vs Projected Pipeline Gas and LNG Imports

5.1.1 Situations of Increased Operational Complexity in Future Grid

Analysis of Scenario 3 showed that the system would be pushed to its limits in two situations: days when curtailed energy from an oversupply of renewables could not be stored (i.e., high-renewable days), and days in which wind and solar resources were in a drought (i.e., low-renewables days). Figure 5-2 shows two 24-hour snapshots that illustrate load and resource makeup during these two situations. On high-renewable days, typically during the spring or fall seasons, there is a large amount of both offshore wind and PV, which leads to large amounts of curtailment. During peak solar output hours, we observed that even with simultaneous charging of BESS, pumped storage, and EV Flex (as explored in Alternative B), and external tie-lines exporting at their limits, there was more than 15.4 GWh of energy that needed to be curtailed in a single hour. The system was unable to capture this renewable energy for use at a later time due to insufficient storage (600 MW of BESS plus existing pumped hydro storage). The system would require increased energy storage capability to utilize this curtailed, renewable energy.

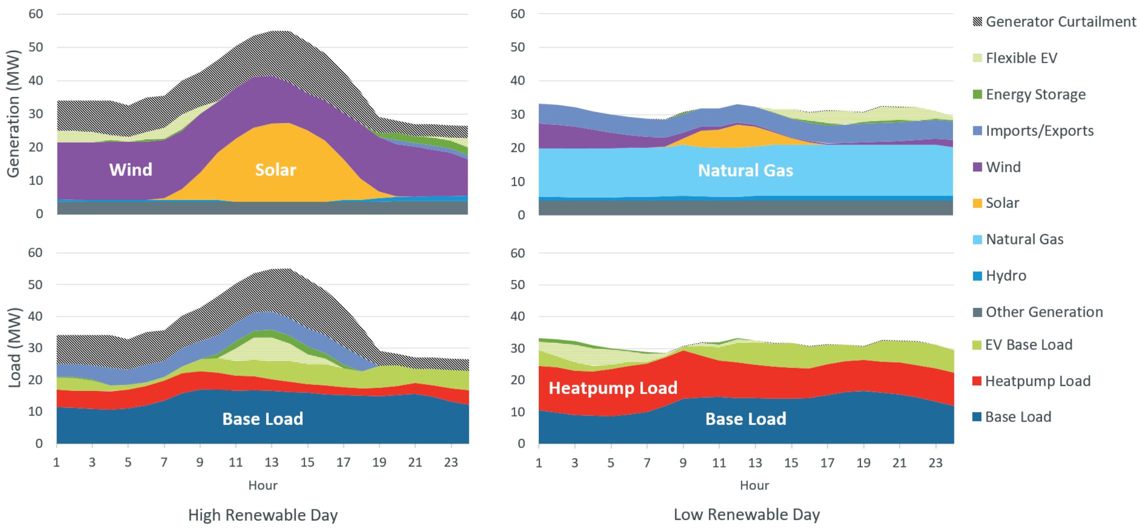

Figure 5-2: Load and Generation during a Low Renewable Day and a High Renewable Day in Scenario 3 (2040)

On the low renewable day, we observed a very different set of conditions. The late December day demonstrates a common occurrence during the winter season and some summer periods when the system relies on dispatchable generation when solar and wind are not providing adequate energy. The particular day shown occurs at the end of several days of continued low wind and solar output, and we find that BESS and pumped storage is only able to shift what little wind production occurs in the morning to the afternoon, which is not sufficient. The bulk of the load is served by natural gas resources, and this day in particular has the highest production from natural gas-fired resources in Scenario 3. Peak hourly natural gas production was 15.2 GW, with an annual total of 356 GWh of energy produced by the natural gas fleet. Using the ISO's fuel availability curve for 2025 as a rough approximation, 0.4 Bcf of pipeline natural gas is available and 1.4 Bcf of LNG is available, based on temperature and projected heating demand on the local gas suppliers totaling 1.8 Bcf. On this particularly high production day, a total of 2.7 Bcf would be needed, resulting in a deficiency of 0.933 Bcf. This substantial gap between gas supply and simulated gas demand signals a need for a large amount of dispatchable stored energy. Without changes to the resource mix, an increase in capacity of stored fuel, dual-fuel operations, or emergency operator actions designed to reduce demand, customers could be dropped from electrical service.

5.1.2 Main Scenario Results

Of the four main Scenarios, Scenario 3 modeled a future with the largest increases in both renewable resources as well as new electrification load. The other main Scenarios provided outlooks on future outcomes that have fewer renewable resources added. With no additional announced retirements and additions only from FCA 15 and state contracted resources, Scenario 0 was very similar to today's system. Figure 5-3 shows that Scenario 0 was the only Scenario that had some amount of coal resource production (all other scenarios retired all coal resources). Coal is more economical than some natural gas units in the model but is only dispatched selectively because these resources are less operationally flexible (they take longer to start-up and need to stay online for longer periods of time). Scenario 1 had additional renewable resources added, as well as electrification loads, resulting in greater PV and wind output. Scenario 2 had similar loads to those seen in Scenario 1, but higher injections of PV, which lead to reduced natural gas consumption.

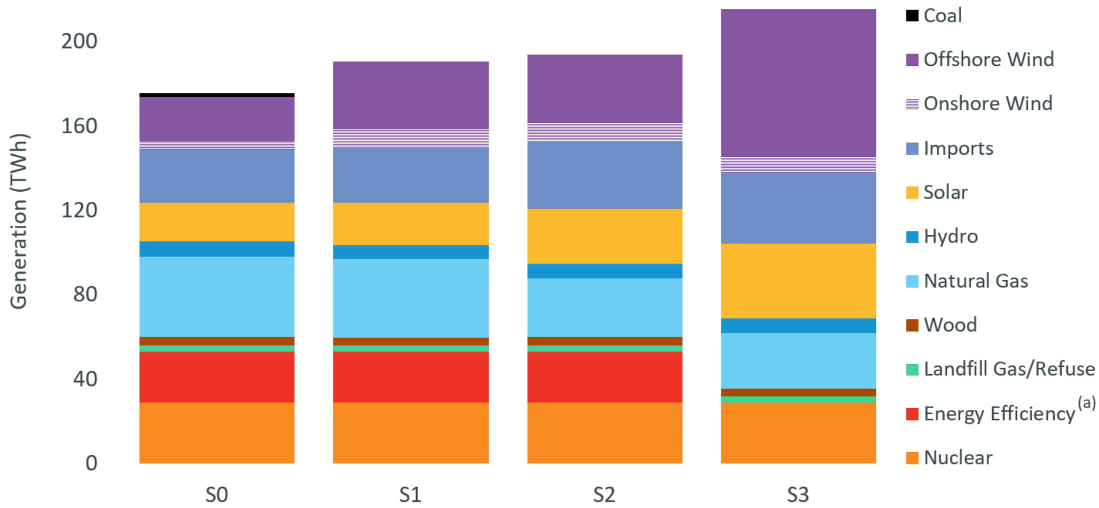

Figure 5-3: Anticipated Annual Generation by Resource Subtype for Main FGRS Scenarios

(a) EE was included in the load of Scenario 3

5.1.3 Alternative Scenario Results

While comparisons between the main reference Scenario 0 and higher renewable penetration Scenarios can provide a look at overall trends, it may be difficult to find the specific drivers of some results because of the many of assumption changes across Scenarios. The Alternatives applied to various Scenarios offer insights into how more isolated changes affect outcomes.

Alternative A examined energy banking with Hydro-Québec, and Alternative B examined vehicle-to-grid storage. Both alternatives revealed the difficulties in modeling energy storage using current production cost modeling software. The energy storage logic which modeled BESS, pumped storage, and flex EV charging used LMP arbitrage to determine when the resources would be economically dispatched. For each day modeled, the energy storage algorithm forecasted one week ahead to find opportune times to charge and discharge energy and maximize profitability. Resources would then be deployed in the model based on this pattern and updated after each daily cycle. This often led to situations where energy storage was depleted before a period of wind and solar drought the following week. The inability of the model to transfer oversupplied energy to longer periods of higher LMPs resulted in the use of more natural gas units, which resulted in higher emissions and production costs. Comparing the results of the base Scenarios to Alternative B with its 100 GW of 2-hour batteries revealed very little difference in curtailment of renewables. Current industry philosophy regarding the use of batteries posits that short-term price arbitrage could be used to maximize profits and result in greater overall reliability of the power grid. FGRS finds that this assumption is not supported by the current modeling approach, and that operation of storage in this manner may not necessarily support system reliability goals.

Alternative A used an algorithm developed outside of the current software model to explore the minimization of fossil fuel generation using energy banking with Québec. This two-step approach first ran a simulation allowing for unlimited exports to Québec, tracking the total quantity of imports that were curtailed in a first pass. Using the amount of energy exported to Québec and the total curtailed energy from the first pass, a profile was developed to re-import the banked energy as part of a second pass designed to minimize natural gas production. Since the energy banking logic looked at the entire year rather than a one-week ahead window, it was able to capture all oversupplied energy and return almost all banked energy. While the use of an unconstrained line that peaks at 10,743 MW imported may be unrealistic, it can help provide insights about how facilities in Canada could be used as an energy storage resource. In examining the entire year and assuming the capability to transfer any amount of energy at one time, Alternative A eliminated any curtailment of New England renewables and imports on existing tie-lines and NECEC while significantly decreasing natural gas production and emissions.

Of all the alternative Scenarios, Alternative C had the smallest change from the base Scenarios' assumptions, as its main shift in assumption was the retirement of nuclear units. However, this small change revealed how delicate some of the Scenarios – particularly Scenario 3 – really were. When nuclear units were retired in Scenario 3 Alternative C, we suddenly observed unserved energy – customers losing power – for 79 hours throughout the year, peaking at 6,160 MWh (19.7% of load) unserved energy during a single hour. After further analysis, results showed that if the energy storage logic had anticipated this gap between supply and demand outside of the one-week energy storage commitment period, there would have been no unserved energy. This example shows how small changes in assumptions about grid operations or supply and demand can have a large impact on the results of the production cost model. This issue is described further in Lessons Learned for Future Studies. Aside from the unserved energy, the retirement of nuclear units led to an increase in carbon dioxide emissions of up to 50%. In Scenario 2, carbon dioxide emissions increased from 22.4 million tons annually to 33.6 million tons, representing an 11.2-million-ton increase, or approximately 50%, in total emissions. With the retirement of the two nuclear plants in New England, reaching the states' future emission targets will be challenging.

Of all the Scenarios, Alternatives D and E contained the most ambitious assumptions in order to test the possibility of a 100% emissions-free grid. These Scenarios pushed the modeling capability to its limits, and the limitations in our current software's Energy Storage algorithm resulted in a sub-optimal dispatch. Unserved energy was observed in Scenarios 2 and 3 D/E in very small quantities. Scenario 3 Alternative D saw 0.16 TWh of unserved energy. To meet such large loads without dispatchable fossil resources, the Scenario assumed a massive quantity of renewables, leading to a large amount of curtailed renewable energy production. The 231 TWh of energy demand in Scenario 3 Alternative D is served by over 190 TWh of wind and solar yet still sees a total of 56 TWh of curtailment and relies on 41 TWh nuclear, hydro, imports, and small amounts of reduced capacity MSW/LFG and wood units. With zero-cost resources dispatched at threshold prices acting as the dominant resource type in these alternatives, emissions were eliminated and average LMPs and production costs all fell significantly, as expected.

In addition to the unconstrained transmission Scenarios, a small set of Scenarios were run with constraints applied to the internal New England transmission interfaces. These Scenarios sought to provide a high-level analysis of the transmission system under the various future outcomes while providing an analysis of theoretical changes in limits to reduce congestion. In all the main Scenarios, congestion was observed primarily in Northern New England, with additional congestions seen in

SEMA/RI for Scenario 3. This congestion led to increased curtailment of renewables and imports. Assumed transmission upgrades to Northern New England and SEMA/RI showed a significant decrease in congestion and curtailments, but not a complete elimination. Alternatives D and E proved too difficult for the model to run under constrained transmission and thus saw many hours of unserved energy that skewed production cost metrics. Alternative B initially saw congestion in SEMA/RI and Northern New England similar to Scenario 3 when interface limits were enforced. Similar results were observed when those regions had their interface limits increased, with less curtailment of renewables and imports. These results revealed that incorporating a large number of new resources into the system would create challenges with the transmission system. Much more analysis will be needed to explore how the system must be modified to accommodate these changes.

To investigate the relationship between PRAA (probabilistic resource availability analysis) and production cost results, two different sets of proxy mixes determined by the resource adequacy software were added to Scenario 3. Scenario 3_P1(resources retained for reliability with combustion turbines) was modeled by bringing back in the units that were assumed to be retired for Scenario 3 and adding 9,000 MW of proxy combustion turbine (CT) units to meet reliability criterion. We observed that none of the reintroduced units ran, since they were less economical than existing units or the added CT proxy units. CT proxy units ran with a fleet capacity factor of 11.8%, and only operated when there was no curtailment of zero-cost resources. These CT proxy units primarily displaced existing natural gas units, and to a lesser extent imports from neighboring regions. Another modeled alternative, Scenario P6 (onshore wind and BESS in Scenario 3 scaled up to meet resource adequacy criteria), assumed large additions of 9,800 MW of onshore wind and 29,000 MW of four-hour BESS. This Scenario saw significant increases in oversupply of renewable resources, resulting in increased curtailment of renewables and decreased system-wide emissions. By simulating resource mixes from the PRAA in the production cost model, the costs and impact of emissions can be quantified to further inform approaches to a future grid.

While the current production cost model's energy storage logic sometimes struggled to balance supply and demand, the Scenarios provided insight into how the future system might operate, as well as revealing potential issues. Large injections of variable energy resources will provide an opportunity to capture and store oversupplied energy for deployment during wind and solar droughts. Increased injections of zero-cost resources may lead to many hours of low or negative LMPs, and further investigation into the revenue adequacy of resources under these conditions will need to be explored in Phase 2 of this study.

5.2 Ancillary Services

In the New England power system, ancillary services refer to products and functions that allow grid operators to maintain the balance of power supply and demand, and respond to unplanned outages while maintaining a reliable grid. While the capacity and energy market exist to address bulk energy needs, ancillary services help fine-tune the energy balance and procure reserves for unexpected shortfalls. The quantities to manage this fine tuning are typically small and are generally provided by a subset of available resources. These resources self-select to offer into the ancillary service market because of their capabilities. Ancillary services help address the uncertainty of forecasting and the variations of a real-time system. For example, an offline generator that can come online and produce power within ten minutes can participate in the reserves market as "ten-minute non-spinning reserves". Resources must be able to increase or decrease their power output to meet both large and small changes in demand. Grid operators must also keep generation in reserve for unexpected outages or disturbances to the grid. Though ancillary services are a small part of the electrical market, they are essential in maintaining electrical reliability.

Regulation and **reserves** are two ancillary service products studied in the FGRS. Regulation is the ability of resources to fine-tune their output to account for small changes in demand. Reserves refers to either online or offline capacity set aside to respond to sudden disturbances. Different reserve types have different MW requirements. If the quantity of available reserves drops below the requirement, a penalty price is enforced and other generators are incentivized to come online to meet demand. When the ISO New England reserves market produces high reserve prices, this generally increases energy prices as well and thereby incentivizes generators to provide energy and reserves to serve demand. **Ramping** is another component of ancillary services, though it is not a product in the current market. Ramping refers to the ability of dispatchable resources to increase or decrease their power output over short time periods.

Several **ancillary services** markets exist to procure services for the power system that can ensure reliability in the short-term. These services go beyond the production of power and include tools that allow grid operators to increase or decrease resource output on a moment-to-moment basis, called regulation. Other examples of ancillary services are mechanisms that allow a resource provider to preserve power in a state of readiness in order to respond to unexpected contingencies on the power system. Black start services can be used to initiate power generation when no other electricity is available to the power grid.

The ISO administers day-ahead and real-time energy markets. All resources are required to offer their available energy into the day-ahead market and each resource that is selected is given an hourly schedule for the next day. Resources that did not receive a day-ahead schedule for any or all of their available energy can offer to provide one or more of the ancillary services of regulation, ramping and reserves in the real-time market in addition to energy. The real-time market exists to address changes in actual realized demand and changes in supply. This is supplemented by the regulation ancillary service market, which provides automatic fine-tuning of generation between dispatch intervals.

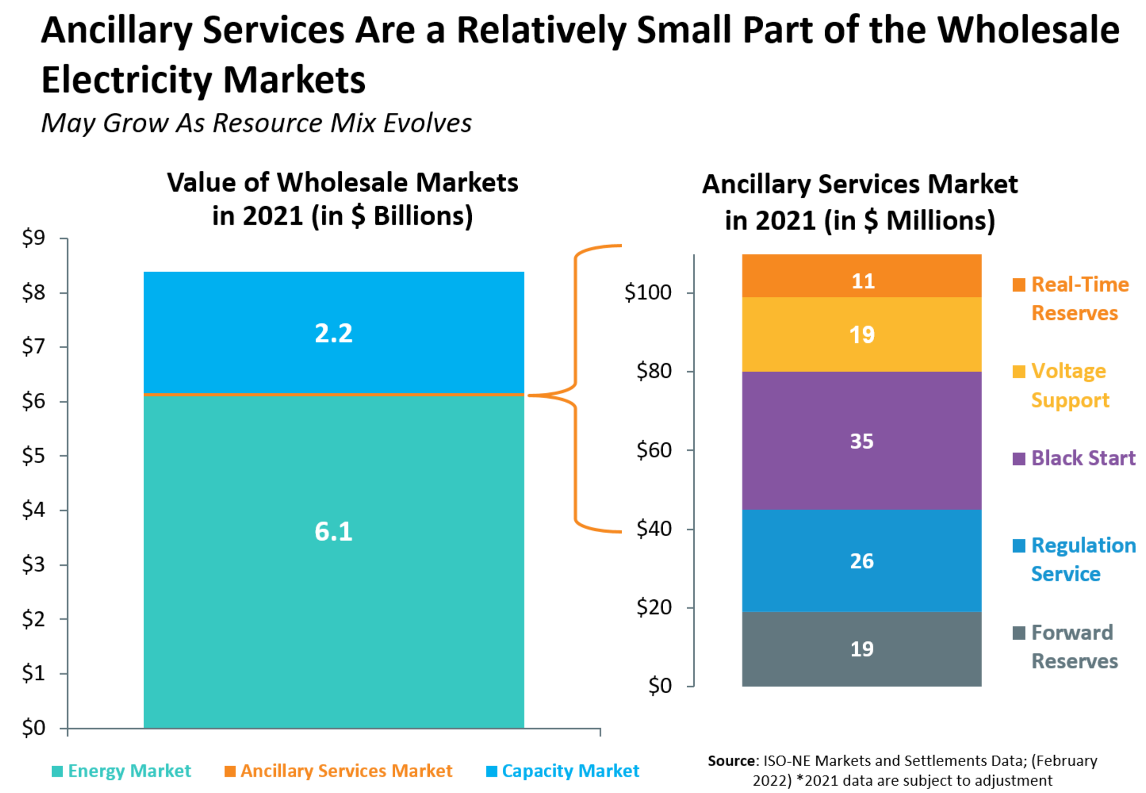

Figure 5-4: Illustration of Ancillary Services as a Portion of the Wholesale Electricity Markets

5.2.1 Ancillary Services and the Renewable-Dominant Grid

Ancillary services are a very small portion of today's markets, as shown in Figure 5-4. Moving forward, increasing amounts of wind, solar, and energy storage resources are anticipated to supply the grid. In their current mode of operation, wind and solar resources produce the maximum power they are capable of in given weather conditions and local transmission constraints. This output can be quite variable, and predicting generation accurately depends on precise weather forecasts. As output from these resources fluctuates up and down, other resources must fill in the gaps. Energy storage or dispatchable resources can provide this service.

Variable resources, such as wind and solar, need to forecast how much power they think they will be able to produce the next day. Though forecasting methods are becoming increasingly accurate, there is still a significant amount of uncertainty associated with predicting future weather patterns. Forecast error (along with load forecast error) creates a difference between day-ahead generation schedules and real-time conditions. As more power is produced by variable resources, differences between day-ahead schedules and real-time conditions may grow larger, even if forecasts increase in accuracy. As overall magnitudes of power produced from renewables increase, the overall megawatt difference between forecast and real-time may increase significantly. As a result, dispatchable generation will need to react quickly to account for real-time weather conditions or price signals sufficient to induce wind and solar resources to change their dispatch patterns (to the extent possible) to accommodate the changed circumstances. New England's ancillary services must prepare to maintain a reliable power balance while integrating large amounts of wind and solar generation.

5.2.2 Analysis

The purpose of the FGRS ancillary services analysis was to investigate if resources in each Scenario will provide necessary amounts of regulation, reserves, ramping and load following, and provide insight into expected revenues from the ancillary services markets.

The ISO power and market simulator was used to perform the ancillary services analysis. The tool uses a one-minute time period to capture rapid changes in wind generation, solar generation, and load. Additionally, it has four control layers reflecting the current ISO day-ahead scheduling, real-time commitment and real-time dispatch. The day-ahead layer looks at the predicted future wind, solar, and load patterns, but applies some amount of forecast error. This layer then schedules generation for the next 24 hours depending on its predictions. Afterwards, real-time layers compensate for any discrepancies between the day-ahead prediction and the real-time conditions by ramping resources up and down. The real-time layers use reserves if the real-time conditions are sufficiently different from the day ahead predictions. Finally, regulation provides small changes to generation between dispatches in the real-time layer. Since regulation is the last product in the model that can meet load changes, that regulation need was used to show gaps in the ability of a Scenario to meet flexibility requirements. Reserves were monitored and penalty prices were calculated for the minutes that reserve requirements were violated. Ramping was monitored, however there was no penalty price associated with insufficient ramping capability.

The simulator had some limitations, particularly concerning storage. Pumped storage and BESS units performed price arbitrage but did not perform other functions. In the model, either type of storage could only switch between charging and discharging every 15 minutes and could not directly provide reserves. While it is expected that future storage could provide reserves and/or regulation, this was not modeled.

5.2.3 Simulation

A sample result of a Scenario 1 day (2040) and the need for ramping and regulation as modeled by the power and market simulator can be seen in Figure 5-5 below. The day-ahead layer of the simulator estimated load, wind, and solar behavior for the next day. In the graph, the difference between the day-ahead prediction and the real-time conditions are shown as a function of time for these two components. The day-ahead layer then scheduled thermal generation and storage to meet the anticipated net load. Then real-time layers dispatched generation to meet deviations in the net load prediction. In the early morning prior to 8 AM, wind produced more power than expected, resulting in a lower net load, which required a ramp-down of dispatchable generation. From 8 AM to 12 PM, both wind and solar produced less than predicted, leading to a higher net load that required a ramp-up of dispatchable generation. From 6 PM until 10 PM, wind overproduced which resulted in a lower net load, and balance was maintained by dispatchable generation ramping down. Throughout all of this, regulation provided fine-tuning between dispatch periods.

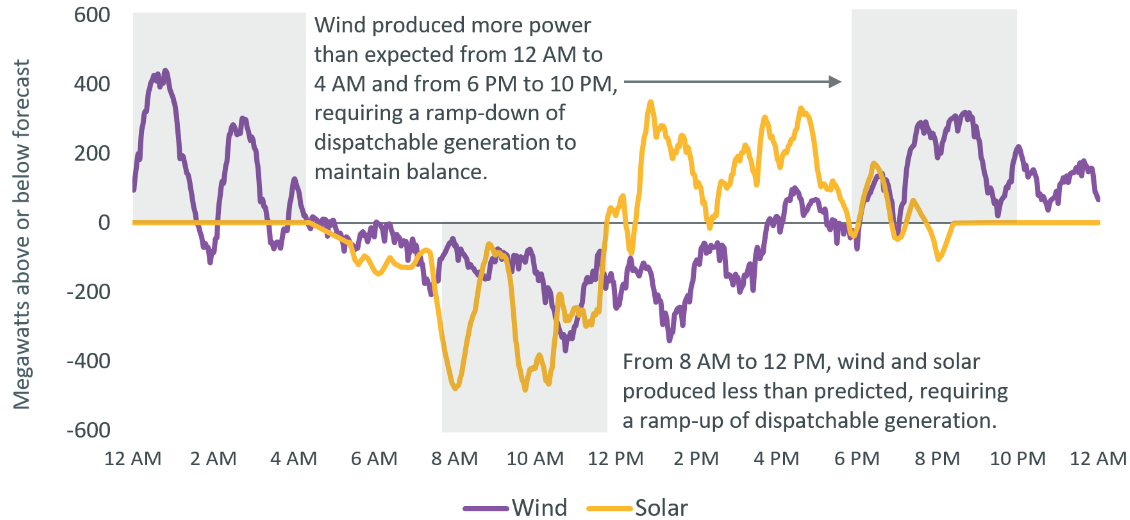

Figure 5-5: Difference in Real Time vs. Day Ahead Forecast Load (Scenario 1, 2040)

The program monitored load and generator behavior, including regulation, ramping, and reserves over one simulation year. Each Scenario only had access to a limited amount of each product, and it was possible for the grid to exhaust one of these products during a commitment time-step before it could be re-dispatched. For reserves, a penalty price was applied when the number of reserves dropped below a predefined reserve requirement. Regulation was also assigned a price depending on how much it was used. After the simulation was complete, the data was used to determine the ability of a Scenario to meet generation and load variability as well as the predicted cost of the reserves and regulation.

5.2.4 Results

In general, increased amounts of wind and solar generation led to an increased need for regulation, usage of reserves, and periods of reserve violations. Scenarios that contained large amounts of dispatchable generation had minimal minutes of reserve violations, which mimicked the current ISO system. On the other hand, Scenarios with aggressive electrification and aggressive retirement of dispatchable generation without sufficient replacement from other resources saw increased minutes of reserve violations.

As electrification leads to larger loads, power systems must not prematurely retire too many dispatchable units or fail to adequately replace their reliability attributes if they are retired. Variable resources and energy storage can provide large amounts of energy to a system, but a balance between supply and demand must be maintained for reliability or operability. Scenario 3 and Scenario 3 Alternative B even showed reserve depletion when the system ran out of resources to commit, which resulted in large regulation needs. These Scenarios were thus deficient in reserves and unable to meet flexibility requirements. In other words, such Scenarios contained many minutes where reserves dropped below their requirement threshold, triggering high real-time energy prices. If reserves dropped to zero, the system would experience unserved energy. In a real system, reserve deficiency would lead to expensive administratively-imposed prices and possible rolling disconnection of customers after all operator emergency measures are applied to maintain system reliability. In Scenarios where reserves were not completely depleted, increased penetration of wind and solar generation was positively correlated with a higher regulation need. In a future system, increased variable generation will require either more frequent dispatch intervals or more regulation capability between dispatches.

> The Forward Capacity Market (FCM) is the region's **capacity** market. It seeks to ensure that the system has sufficient resources to meet future needs by procuring resources to meet projected demand for electricity three years in advance. Capacity payments help support the development of new resources and retain existing resources They also serve as a revenue stream for resource providers that help meet demand during periods of system stress but do not operate regularly over the remainder of the year.

Adequate reserves will be an important part of future ancillary services. In the current New England grid, reserve requirements are set as a percentage of the first or second largest contingency (i.e. if the largest generator (which defines the first contingency) on the system is a 1,200 MW nuclear unit, the total 10-minute reserve requirement may be 120% of the largest contingency, or 1,440 MW). This ensures that reserves are sufficient to mitigate the worst-case unit outage with some additional margin. However, in a future grid with high penetrations of wind and solar resources, the largest contingency could be caused by cloud cover over a critical area or an unexpected drop in wind speed on large wind farms in close proximity to each other. Moving forward, the need for ancillary services will increase, but currently fewer dispatchable resources are expected to provide them.

Of the scenarios which met reliability criterion, minutes of reserve scarcity varied according to a number of factors. Scenario 0 experienced minimal minutes of reserve scarcity due to a large margin of dispatchable capacity and low penetrations of variable resources. Of the Scenario 3 proxy mixes modeled, Scenario 3_P1 (resources retained for reliability with combustion turbines) had the lowest number of minutes of reserve scarcity due to a similar large margin of dispatchable generators. Scenario 3_P6, which increased onshore wind and energy storage, had the most minutes of reserve scarcity. When one variable resource was built out, its variability became a driver for higher reserve usage. Scenario 3_P7, which built out energy storage and all variable resource types, had fewer minutes of reserve scarcity than Scenario 3_P6. Maintaining a balanced resource mix may help reduce the need for different reserve requirements.

Though reserves may be provided by wind, solar or energy storage units, the simulations reveal that a core of dispatchable resources will be necessary to provide ancillary services to the system. During the clean energy transition, the system may need more flexibility to maintain the balance between an increasingly variable energy supply and increasingly weather-dependent demand.

5.3 Resource Adequacy

The resource adequacy simulations of the FGRS were a new addition to economic studies. They were added to ensure that future resource mixes will be able to support a reliable power system. The other analyses contained in FGRS evaluated just a single year and did not consider unexpected failure of power system components (known as contingencies or forced outages). Resource adequacy, on the other hand, considers a near infinite combination of possible resource contingencies and performance levels. In short, it simulates thousands of load and resource availability outcomes in the year of interest, and in doing so can determine the risk of not serving all customer demand and evaluate if possible future grids will meet today's reliability standards. The FGRS reliability analysis covered two study types: RAS (resource adequacy screen) and PRAA (probabilistic resource availability analysis).

The RAS is used in the planning and operations of today's grid as part of the Forward Capacity Market (FCM). The RAS analysis identifies what total amount of resources must exist for a given mix of demand to serve load, known as an installed capacity requirement (ICR). Meeting the ICR ensures that enough resources are available to provide customers (known as firm load) with reliable power service, and that customers will not be disconnected from the power grid due to insufficient resources more than one day in ten years (referred to as Loss of Load Expectation (LOLE) of 0.1 days/year or less). The same analysis used in today's system procurement was applied to the hypothetical future Scenarios of the FGRS.

The FGRS also performed a modified form of RAS called PRAA. In traditional RAS, wind and solar resources were modeled using a predetermined hourly static value during pre-defined reliability hours applied to every hour of the season. While this approach was generally sufficient to model the reliability of the existing grid with relatively low penetrations of renewable resources, the FGRS anticipates that with higher quantities of wind and solar, modeling these resources on an hourly basis that reflects variable historical weather-driven conditions would be a more accurate approach. This change in assumptions is a key difference between PRAA and RAS analyses. Using both RAS and PRAA helped evaluate the reliability of different future resource mixes and explore whether today's RAS approximations will still be valid for a future grid with significant amounts of variable resources.

The reliability analysis focused on Scenario 3 since resource adequacy analysis is labor intensive and time consuming, and Scenario 3 had the largest resource shortfall. Additionally, it was believed that a subset of cases would be sufficient to identify any reliability issues.

5.3.1 RAS and PRAA Results

The RAS and PRAA analyses showed whether the simulated resource mix had either excess ("long") or insufficient ("short") capacity to serve load. While the magnitude of long-ness or short-ness varied between the RAS and PRAA results, they were directionally similar. The PRAA results were higher than those in the RAS, as RAS overestimates the reliability of renewables during the hours of highest risk. The FGRS results showed that to assess a high renewables system more nuanced modeling of renewables is required. While fixed output values used in RAS for solar and wind are sufficient for today's system, that assumption is no longer adequately detailed in Scenarios where they are dominant resources and widespread wind lulls and cloudy weather become more impactful.

Scenarios 0, 1, and 2, which simulated either a version of today's system in 2040 or slightly increased renewable and electrification deployment, were all long on resources to various degrees. Most load loss risks were in the summer months, with some risks in the winter months.

However, Scenario 3, with its more ambitious renewable and electrification deployment, was short on resources. When a Scenario is found to be short, (i.e., not meeting reliability criteria), the FGRS adds additional units to the Scenario (called "proxy" units) until the Scenario meets criteria. These units are representative of specific resources. In reliability analysis, the FGRS quantifies the number of additional units of various types that would be necessary to maintain a reliable system. In the initial FGRS analysis, a moderate amount of additional BESS were added as proxy units (900 MW) and then quick-start peaking units known as combustion turbines (CTs) were added until the Scenario met criteria. Scenario 3 needed a large amount of additional proxy units to meet reliability criteria.

However, in Alternative B, due to the large amount of vehicle-to-grid electric vehicles, adding additional BESS as a proxy, in any amount would not close the gap. In this Scenario there was not sufficient energy in the resource mix to recharge the BESS. As a result, only CTs were added as proxy units in this Scenario. Only a small amount of CTs were needed. However, it is important to note that Alternative B started with much larger quantities of resources than Scenario 3. The results of Alternative B showed that due to energy depletion BESS alone cannot ensure a reliable system – the grid must also have enough resources to charge the BESS.

Applying RAS and PRAA to future grids showed that as the grid moves toward net-zero emissions, all "known" assumptions must be checked and verified. New England's current grid is reliably summer peaking, and reliability hours underlying the RAS approximation (the hours with the highest risk for the grid) are in the evening. Results from Scenario 3 showed the system moving to a winter peaking grid, with reliability hours in the pre-dawn winter morning in addition to the evening. As the region transitions, reliability assessments will need to be conducted on a 12-month basis instead of seasonally.

5.3.1.1 Scenario 3 Proxy Mixes

Table 5.1: FGRS Scenario 3 Proxy Mixes

Scenario	Scenario Description	Base Renewables + BESS	Perfect Capacity	Combustion Turbine	BESS	Offshore Wind	Onshore Wind	Solar	Total Proxy MW Added	**Total Installed Capacity**
S3_P0	Perfect Capacity Resources	47,979	11,750						11,750	79,048
S3_P1	Resources Retained for Reliability and CTs	47,979		9,000 + 4,396[1]					13,400	80,698
S3_P2	Only BESS Resources	47,979			>100,000[2]				> 100,000 (0.1 LOLE not Reached)	>167,298
S3_P3	Only OFSW Resources	47,979				155,000			155,000	222,298
S3_P4	Only ONSW Resources	47,979					85,000		85,000	152,298
S3_P5	Only PV Resources	47,979						>230,000	> 230,000 (0.1 LOLE not Reached)	>297,298
S3_P6	ONSW and BESS Resources	47,979			29,000[3]		9,800		38,800	106,098
S3_P7	Solar/Wind/BESS Resources Mix from Pathways Status Quo Scaled	~52,400			~9,000[3]	~11,000	~3,000	~14,000	37,400	109,119
S3_P7 3,000 MW DEFR	S3_P7 with 3,000 MW of Dispatchable Emission Free Resources Added	~52,400		3,000 DEFR	~3,300	~4,000	~1,100	~4,900	18,500	88,019

[1] 4,396 MW assumed retired in S3 was retained for reliability (oil, coal, older natural gas) in this scenario
[2] Two-hour duration
[3] Four-hour duration
All values are in MW

This additional analysis resulted in a few key takeaways. Maintaining a significant quantity of dispatchable units will significantly reduce the overall build-out of renewables needed to meet environmental goals and reliability criteria. These dispatchable resources do not necessarily need to be carbon-emitting, but could be any resource with similar attributes to a current-day dispatchable resource. Examples include today's fossil fuel units running on synthetic or renewable fuel, new small modular nuclear units, co-located storage and renewables, large-scale solar or renewables operated in particular ways to maximize dispatchability, or imported hydro-power from Québec.

Without dispatchable units, a significantly large build-out of renewables is required. The FGRS analysis also finds that resource diversity is critical. In cases where only a single unit type was added, Scenarios either did not meet reliability criteria or required what may be infeasible quantities of those resources. The FGRS also explored a few resource mixes that used diverse combinations of onshore and offshore wind, solar, battery storage, or hypothetical dispatchable emission-free resources to meet resource adequacy criteria. This diversity reduced the need for new renewable and storage resources by up to 17,000 MW. This analysis also shows that resource adequacy criteria can be met by a variety of resource mixes but that dispatchable resources are particularly effective at meeting this criteria.

Section 6 : Gaps & Key Takeaways

The analysis contained in the FGRS identified several potential power system gaps and key takeaways with regard to the future grid envisioned through the various Scenarios. **Gaps** are defined as notable issues or concerns with the modeled system. The solution to a gap may be unknown and is beyond the scope of an economic study, but it is an identified problem which must be resolved if the future New England power system reflects any one of the potential Scenarios modeled in this study. A **takeaway** is a prevalent or recurring theme identified in a Scenario or groups of Scenarios. These gaps and takeaways include issues around energy adequacy, resource and demand flexibility, resource mix diversity, and lessons learned for future economic studies. Each of these areas will be expanded upon below.

6.1 Energy Adequacy

6.1.1 An Outsized Demand for Gas

The FGRS modeled several different potential Scenarios for the future grid. It was generally expected that as the quantity of renewable resources in these Scenarios increased, the region's reliance on fossil fuel resources would decrease. Though emissions, LMPs, and utilization of fossil fuel resources did decrease, this decrease did not result in a commensurate reduction in the need for dispatchable resources dependent upon stored fuel. With increased electrification of transportation and heating, electrical demand increased sharply and shifted away from historical patterns. As Figure 6-1 shows, under the resources specified in FGRS Scenario 3, this resulted in a 53% drop in annual natural gas consumption for electricity production but only a 14% drop in peak-hour consumption versus 2021.

The results demonstrated that dispatchable resources in the future do not necessarily need to be carbon-emitting, but they should have similar attributes to today's dispatchable resources. Examples of such resources with these key attributes not explicitly studied might include today's fossil fuel units powered by synthetic or renewable fuel, new small modular nuclear units, co-located storage and renewables, large-scale solar or renewables operated in particular ways to maximize dispatchability, or imported hydro-power from Québec.

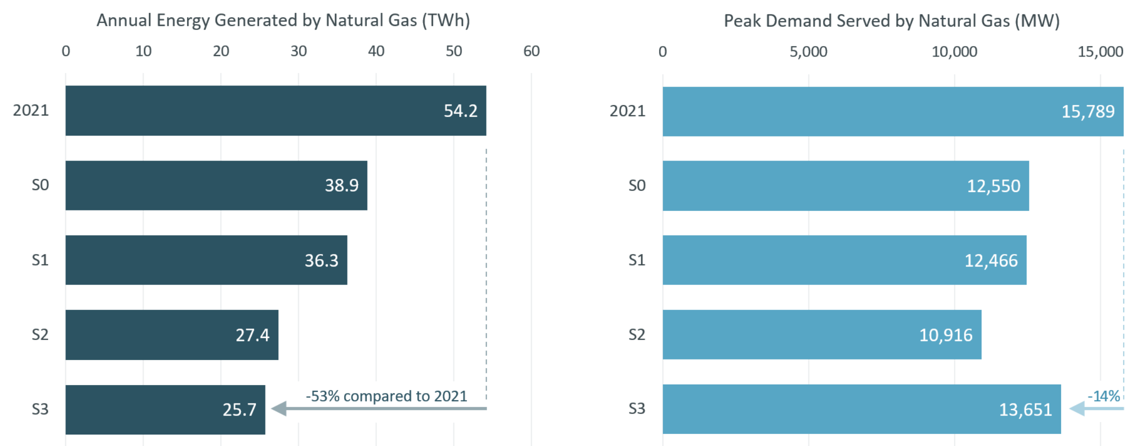

Figure 6-1: Historical and Studied (2040) Total and Peak Natural Gas Generation

The simulations revealed that solar resources are not helpful in meeting the winter early morning and evening periods of high demand, and potential wind lulls and droughts could prevent wind resources from supplementing these gaps. With the resource mixes modeled in the FGRS, this leaves natural gas as the remaining option to serve demand. However, the need for natural gas may at times exceed available fuel supply and pipeline delivery capabilities. In the natural gas network, primary residential and commercial heating demands are prioritized over electric generation. As a result, the New England power grid is currently forced to utilize liquefied natural gas, coal, and oil in some winter conditions. As home heating is electrified, oil, propane, and other high emission systems are likely to be the first systems replaced before natural gas heating. This will drive demand for electricity, which will subsequently increase natural gas-fired resource usage and continue the grid's reliance on gas pipeline capabilities during these peak winter periods.

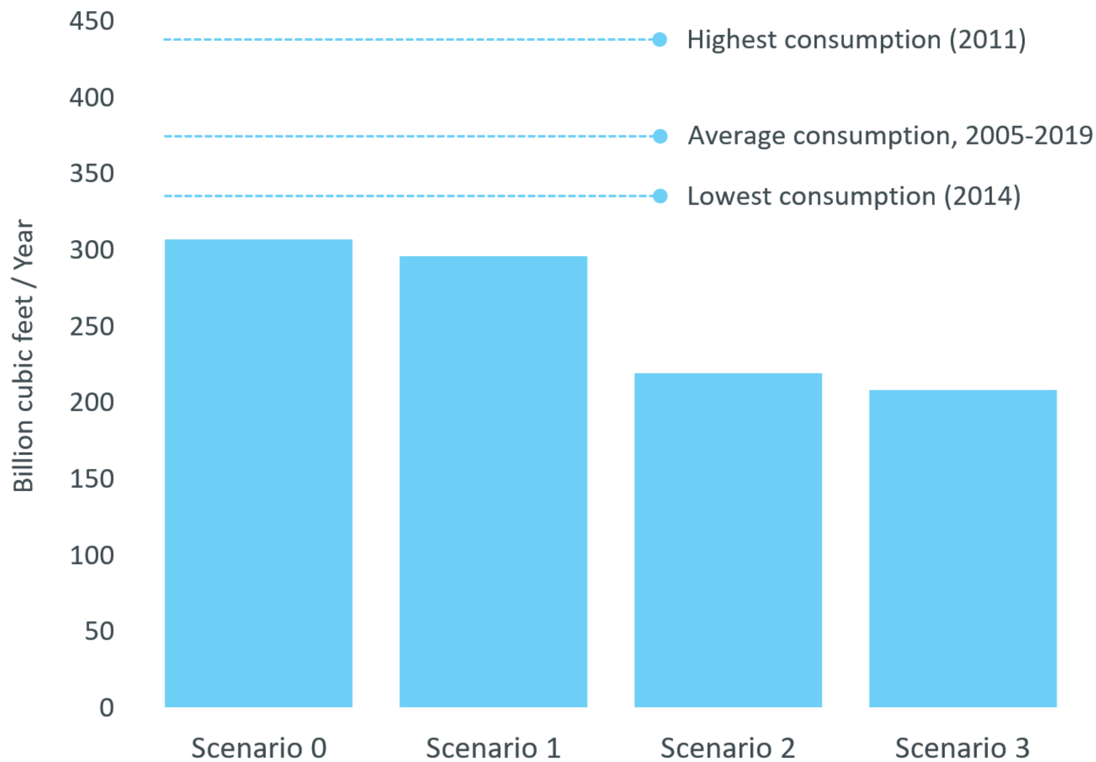

Figure 6-2: Historical and Anticipated Natural Gas Consumption for Electrical Production

The analysis utilized in the FGRS assumed natural gas generators and utilization of a natural gas pipeline and delivery system. Figure 6-2 shows the anticipated natural gas consumption by FGRS Scenario compared to historical consumption. However, it is possible that by 2040, a gas fuel that is renewable or synthetic may have been developed to reduce the carbon footprint of this fuel. Regardless of the specific gas type in use, the FGRS analysis shows immense amounts of renewable energy curtailment in most cases, but particularly in aggressive electrification and renewable deployment cases.

The results of this study show that significant penetrations of renewables along with increased electrification will create an increase in natural gas demand during cold weather periods when wind and solar are experiencing production lulls. Assuming that a comparable amount of natural gas will be consumed for direct heating in 2040 as it is today, more gas infrastructure may be required to meet the increased demand from the electrification of oil and propane heating loads and electric vehicles.

Figure 6-3 shows that for Scenario 3 there are several days during the cold months where the system is at risk of not having sufficient fuel, in FGRS's assumptions, natural gas, to support the demand for electricity production to serve higher winter demand. Multiple Scenarios explored in this study indicate that there would be insufficient gas infrastructure to meet these demands on some days. Dual fuel units capable of using locally stored oil in addition to natural gas would assist in supporting the reliability of these Scenarios, however it is not known whether locally stored fuel resources would be allowed or economical in a future electric grid.

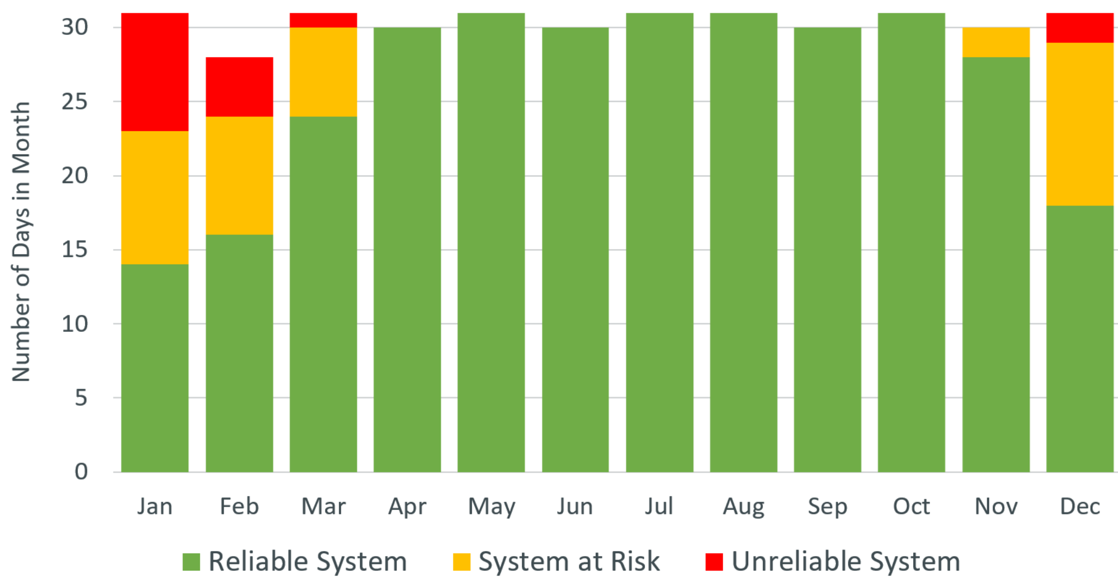

Figure 6-3: Days Per Month of Natural Gas Supply Risk Under FGRS Scenario 3

The Scenarios with the most heating electrification and renewable penetration showed interesting natural gas usage dynamics. Of all the Scenarios, these modeled the most hours with zero natural gas generation. However, they also modeled the highest peak usage of natural gas of any Scenario. Natural gas, coal, and oil units often had net negative revenue before additional compensation (called uplift). These units are required in the Scenarios studied for grid reliability, but they require uplift to be made whole. Note that this analysis did not consider compensation from sources outside the energy markets (capacity payments, state contracts, etc.). Some form of economical stored energy will be needed in future conditions, and the FGRS analysis indicates that the current natural gas network is insufficient, by itself, to meet these energy storage needs.

This analysis of future natural gas usage matches the high-level transmission analysis of the study even though the gas analysis was run on an unconstrained system. Analysis found that increasing transmission limits in various parts of the system would decrease production costs and curtailment of resources. As bulk energy supply shifts towards variable energy resources, sufficient energy transportation infrastructure will be needed to bring energy to demand centers. Across its Scenarios, FGRS finds the need for multiple 345 kV AC transmission lines. The average 345 kV line requires 15 acres per mile for a right of way. However, underground HVDC lines are another option that could address this need without requiring as much land.

There are many potential solutions to these challenges, and the FGRS explored some of them. For example, Alternative A demonstrated how long-duration storage with Québec could provide energy in place of natural gas during times of peak demand. This Alternative reduced peak hour natural-gas consumption for electricity generation, annual carbon dioxide emissions, and production costs. Resource and demand flexibility, another key takeaway of the study, can also impact peak hour demand.

To help the region improve their understanding of operational risks under future weather extremes, the ISO is working with the Electric Power Research Institute (EPRI) to conduct a probabilistic energy adequacy study for the New England region. Part of this work involves creating a framework of analysis that transforms historical extreme events into future events based on the projected future climate. Although currently a project focused on system operations, this framework may eventually be applied to longer-term planning studies to examine the energy adequacy risks of proposed resource mixes combined with the projected future climate.

6.1.2 Challenges Related to Energy Storage and Charging

Energy storage resources such as BESS and pumped storage hydro were included in the FGRS Scenarios. However, these resources were generally unable to provide sufficient energy storage, and fossil fuel resources were needed to fill the gap. There are also limitations in current production simulation models that reduced the ability of large quantities of BESS to replace dispatchable resources in these Scenarios.

Two alternative Scenarios relied on large penetrations of BESS, but the storage in these fleets were depleted during the winter season. The BESS in these Scenarios could not store enough energy to meet demand between recharge periods. The FGRS found that the supply-and-demand mix envisioned in many of the more aggressive Scenarios did not leave enough time for storage to recharge in the 2019 weather year, even though it was not a particularly severe winter. Price arbitrage (whereby storage charges during low-cost periods and discharges during high-cost periods) is widely seen as a way for large BESS penetration to be both reliable and profitable. However, the FGRS found that although this methodology is realistic for the current grid resource mix, it does not meet the needs of the future grid envisioned in this study. For example, in today's grid, sustained low demand occurs overnight. In a future grid where heating and transportation demands have been electrified and large quantities of wind are installed, the wind lulls can extend for days and even weeks. In these situations, charging opportunities shrink or disappear. Integrated regional energy storage using Hydro Québec's reservoirs is a possible solution, but this study finds that the opportunities to store energy via this method are narrow.

Post-FGRS economic studies will rely on newer modeling software than was used in the FGRS. While this new software lacks a native solution to the problem described here, its flexibility will enable the ISO to explore potential modeling enhancements to improve the modeling of storage in the future grid.

6.1.3 Nuclear Retirement in Conflict with Net-Zero Emission Goals

Some FGRS Scenarios modeled a future grid in which all nuclear generation was retired. The New England nuclear fleet has aged significantly, and some units will be over 70 years old by 2040. The region has already seen the retirement of much younger large nuclear units such as Vermont Yankee in 2014 and Pilgrim in 2019. Though the nuclear retirement Scenarios did decrease curtailment of renewables, most of the replacement energy came from natural gas. With this increase in natural gas generation comes an increase in production costs and emissions.

Without these nuclear units, some FGRS Scenarios showed a risk of unmet demand, and thus grid unreliability. Retirement of nuclear resources exacerbates the need for more stored fuel or energy, and these results indicate that the loss of the remaining New England nuclear units will lead to additional emissions from fossil fuel resources. In short, the retirement of nuclear resources further reduces diversity in supply resources and requires an increase in other resources (such as fossil fuels) to compensate for their retirement.

Though BESS and energy banking Scenarios were partially helpful in addressing the stored energy issue, no one technology will solve this issue. Scenarios that were highly reliant on one resource type (such as BESS or offshore wind) were not effective, or they required possibly unrealistic amounts of one resource type. The most reliable Scenarios were those with a healthy diversity of resources. If the New England power system is to meet the challenge of serving an increasingly electrified landscape, some type of stored fuel or long-term energy storage will be necessary to ride through expected periods of solar or wind lulls as well as droughts.

6.2 Resource and Demand Flexibility

This study's ancillary service results were correlated closely with the penetration of renewable resources and electrified load. Scenarios with lower penetrations of renewables, electrified load, and fewer resource retirements performed significantly better than other Scenarios. Renewable energy resources currently attempt to self-schedule their output to the maximum amount allowed by current weather conditions. However, high-levels of renewables with an incentive to self-schedule will result in highly variable dispatchable requirements, and thus rapidly fluctuating net loads. To maintain a balance of supply and demand, these fluctuations in net loads must be offset by flexible resources that provide regulation and ramping services. However, in the FGRS Scenarios, increased penetrations of renewables coincided with assumptions about increased retirements of oil, coal, and natural gas units, which reduced the aggregate flexibility of the remaining fleet of dispatchable resources. More BESS units may help increase system flexibility by providing reserves and regulation, but future battery behavior is still a large unknown variable that was not studied in the FGRS.

Much of our current grid reliability is provided by dispatchable resources as an incidental part of their operation, but the replacement of fossil fuel resources with BESS and variable resources like wind and solar may require specific identification, quantification, and procurement of dispatchable generation or resources that provide attributes similar to today's dispatchable generation. As an example, the system inertia created by a large spinning metal turbine that is a feature of nearly all traditional power generation is a significant source of momentary power that can absorb small variations in supply and demand. In contrast, power electronic inverters (which are used in PV, BESS, and some wind turbines) do not provide momentary energy storage in the form of inertia. As a result, a grid reliant on inverter-based power could become unstable without the proper analysis and control design. The FGRS found that as penetration of renewables expands, large increases in regulation and reserves will be needed to maintain a reliable system.

The FGRS finds that the degree of variability inherent in large amounts of renewable resources requires more flexible dispatchable resources than are available in these future Scenarios. The ISO used a software workaround in the study to evaluate storage's ability to assist with the required balancing. Results showed that while storage could to some extent assist with real-time balancing, the grid was still not flexible enough to support this resource mix and demand need. The FGRS quantifies this need. The ISO's adoption of new modeling software will allow ancillary services analysis to be more tightly integrated into future studies.

Traditionally, reserve requirements are based on the first or second-largest contingency (unexpected failure of a generator or large transmission line importing power) in a system. This ensures that the system can recover shortly after loss of the largest possible source of power. Moving forward, the largest loss of power over a short period of time could come from variable wind speed, or cloud cover that would impact many different resources. Additional reserve requirements may be needed to cover the increased variability of resources. As more dispatchable resources are retired, wind, solar, or BESS units may need to provide reserves. This attribute was not modeled as part of the FGRS due to software limitations but may be necessary in a future grid. The analysis of the most aggressive clean energy Scenarios in the FGRS finds that under expected peak loads, large amounts of renewable resources are needed to meet resource adequacy criteria, particularly in Scenarios with insufficient diversity of resource types. Results showed that the number of resources needed to meet reserve margins – i.e., how many extra resources are needed to keep the system online in times of stress – will increase by a factor of ten by 2040.

In a future system, increased variable generation will require either more frequent dispatch intervals or more regulation capability between dispatches.

There is an important caveat to these findings. The FGRS used as inputs **current** ramping, runtimes, economic minimum output, economic maximum output, and other flexibility resource attributes that are partially determined by the revenues generated in the current market. Changes in the markets to incentivize increased flexibility or new flexibility properties could result in added reserve or regulation availability for a given resource mix.

6.3 Resource Mix Diversity

As the resource mix changes dramatically, assumptions related to resource adequacy studies will also need to be reviewed. However, the FGRS relied on current practices and procedures in its assumptions. In some of this study's Scenarios, the New England system will become winter-peaking, however many current assumptions are based on a summer-peaking system. Higher winter loads will require new guidelines.

As electrification leads to larger loads, power systems must not prematurely retire too many dispatchable units or fail to adequately replace their reliability attributes if they are retired. Additionally, while not dispatchable, retiring existing clean units, e.g., nuclear resources, without a replacement plan presents challenges. The retirement of the region's nuclear generators assumed in some Scenarios may pose a challenge to grid reliability and could thwart the states' goals to reduce carbon dioxide emissions. In the FGRS, retirement of these units resulted in increased natural gas-fired resource electricity production and commensurate increases in carbon dioxide emissions and production costs.

Adding relatively small, targeted amounts of dispatchable units to the most renewable-heavy Scenario explored in this study (Scenario 3) would significantly reduce the necessary new units of wind, solar, and storage, illustrating the importance of dispatchable resources to the future grid. In the proxy resource adequacy analysis of this Scenario 3 P7 (Resource Adequate Deep Decarbonization), the ISO found that with sufficient fuel, 3,000 MW of dispatchable resources could replace 17,000 MW of the studied mix of wind, solar, and storage.

Current representations of resources often rely on the use of static hourly values. The PRAA process, which models variable resources using historical profiles and is informed by real weather patterns rather than a static value, has shown the benefit of these more advanced tools by revealing shortages as the modeling of variable resources becomes more realistic. The PRAA results demonstrated how the timing of reliability hours will change in the Scenarios explored by the FGRS. As more weather-sensitive variable resources are added to the New England grid, policies informing their capacity abilities must also evolve.

To better understand the continued transformation of our current and projected future resource mix, the ISO is currently conducting a resource capacity accreditation (RCA) study. This study will assess the methodology used to determine qualified capacity values for various resources and technology types, with the aim of better aligning these values with the resources' actual reliability contributions.

6.4 Lessons Learned for Future Studies

Some of the key takeaways of this study relate to the function and scope of economic studies themselves, and to the limitations of current software. The FGRS study was a significant undertaking, with a larger scope than the typical economic study. Additional areas of study were performed (such as ancillary services, resource adequacy, and high-level transmission analysis) and some requests stretched the limits of existing practices and software. Stakeholders have also increasingly requested that the results of economic studies be more actionable. Based on ISO's experience with this study, several improvements are suggested below for future economic study frameworks. While the original focus of this study involved identifying reliability and revenue gaps, ISO discovered as the study evolved that industry study tools and processes are not currently sufficient to fully explore what such a shift in resource supply and demand patterns will require.

In addition, current software often could not model a requested assumption or behavior. Some workarounds were achieved, but in general, current software had trouble adequately modeling power system resources and loads mixes that are more variable, less dispatchable and require increased look-ahead time.

6.4.1 Sequence of Production Cost, Ancillary Services and RAS/PRAA Analyses

In future economic studies, it would be beneficial to run the RAS and PRAA first before performing other types of analysis. In the FGRS, RAS & PRAA were performed after the production cost and ancillary services analysis. When some Scenarios did not meet reliability criteria under production cost and ancillary services analysis, the FGRS reran the Scenarios with altered assumptions to test the effects of the changes in resource mixes. If the RAS/PRAA had been run first, these analyses would have revealed a supply shortage issue sooner, and this step could have been avoided.

The FGRS analysis also exposed modeling gaps caused by a reliance on historical study norms or software limitations, and they represent important issues that will be addressed in future economic studies.

6.4.2 Limitations of a Single Weather Year

Studies like the FGRS use a concept called a "weather year" to inform production from renewable resources and demand for electricity. One Scenario in the FGRS was based on the Massachusetts 2050 Deep Decarbonization Roadmap Study, which used the weather year 2012 as part of its assumptions. In the FGRS, all Scenarios were standardized to the weather year 2019. Analysis of the conversion showed that 2019 had a more normal winter and therefore increased electrical demand as compared to 2012, and as a result, the previous study was "less conservative" in its estimation of grid capabilities. The 2019 weather year had higher electrification loads compared to the 2012 weather year but was much less severe than the most demanding winters in recent history.

While the use of a single weather year has been a common industry practice, this method is not as useful or representative in Scenarios with high penetrations of wind and solar resources. In these Scenarios, weather impacts not just demand, but also supply. Additionally, in a future with increased electrified heating, the severity of a particular winter will affect demand more than in previous years with less electrification. In future studies, it would be beneficial to model multiple weather years instead of one. Recent research suggests using multiple weather years to adequately capture weather diversity. Through parallel work with an outside consultant, the ISO has worked to develop several years of historical correlated wind, solar, and load data which it plans to leverage for future studies.

6.4.3 Need for Modeling of Neighboring Regions

Another improvement for future modeling relates to modeling of neighboring regions. In the FGRS and other past studies, historical diurnal (daily) profiles have been used to model supply from neighboring regions. However, interregional exchange of power will become increasingly important as other regions electrify, decarbonize, and diversify. Additionally, the simplification of using historical import profiles may not be informative of future interregional transfer patterns with different resource mixes and demand profiles in neighboring regions. Expanding upon the modeling of neighboring regions using simulated supply and demand instead of historical data will lead to more insightful model results. Future analyses could model more dynamic interactions across tie-lines, informed by the impact of weather patterns on renewable generation. The FGRS Scenario assumptions represent a level of renewable penetration and electrification that challenge the continued viability of many assumptions used in long-range studies over the last decade or more.

6.4.4 Other Assumptions

The FGRS results also identified other assumptions that could benefit from revision, including:

- *Out-of-market revenues.* These external sources of compensation allow emission-free resources to lower their energy-market offers. In the FGRS, threshold prices were a proxy for these revenues and informed the curtailment order during times of oversupply.
- *Modeling co-located energy storage.* Co-located energy storage is becoming more prevalent in ISO's three-to-five-year market outlook. The FGRS modeled storage units as discrete from the wind and solar resources whose energy they store. The actual behavior of co-located units may help lessen variability by producing a fixed output value, instead of the variable values produced by wind and solar without storage.
- *Modeling of the transmissions system.* Nodal modeling would replace the 13 zone 'pipe and bubble' model with a more detailed and comprehensive bus level model of the New England power system. Although this is more computationally intensive, the results could be more informative, as very detailed transmission, congestion, and pricing data could be obtained.
- PRAA is a better reliability representation than the RAS approach, using reliability hours to estimate a qualified capacity.

As a result of the lessons learned from the FGRS, the ISO is testing this new method in the Economic Planning for the Clean Energy Transition (EPCET) – Pilot Study that is currently underway.

6.4.5 Limitations in Modeling Energy Storage

One frequent problem was related to the study's modeling of energy storage. Scenario 3 assumed 600 MW of 4-hour batteries. The other base scenarios assumed different (larger) values of storage, with some alternatives having large amounts of storage. All Scenarios assumed at least 2,400 MWh of BESS units, with some assuming 200 GWh (EVs in Alt. B) and others up to 2.3 TWh (Alt. D &E). However, outside of pumped storage hydro resources, the modern New England power grid currently has a very small number of energy storage units. Most of the software tools assumed the use of storage for price arbitrage, but price arbitrage becomes complicated during sustained periods of low or negative locational marginal prices (LMPs). The FGRS analysis found that modeling storage with the objective of price arbitrage did not fully address the needs of the overall future power grid. In the current software models, storage is generally dispatched on a daily basis or seven-day basis, and not in concert with other dispatchable resources. With larger penetrations of renewables, modeling longer periods (such as seasonal storage) may be necessary. It is also plausible that energy storage will be used to provide reserves or regulation, but the software used in FGRS could not adequately model these uses.

When nuclear units were retired in Scenario 3 Alternative C, results showed unserved energy – customers losing power – for 79 hours throughout the year, peaking at 6,160 MWh (19.7% of load) unserved energy during a single hour. If the energy storage logic had anticipated this gap, there would be no periods of unserved energy. This is an example of how small changes in assumptions about grid operations or supply and demand can have a large impact on the results of the production cost model.

The ISO is currently shifting to new simulation software that is more flexible and able to better reflect commonly imagined future uses for storage, and thus improve our evaluation of BESS's usefulness to the future grid.

6.4.6 Simplification of Wind and Solar Resources

Beyond storage, treatment of wind and solar resources was also simplified to fit current software tools. Some software was designed to model large amounts of traditional dispatchable generators, with wind, solar, and energy storage as added features. When large portions of energy are supplied from variable resources and storage, the software lacks the complexity to fully model and dispatch these resources.

6.4.7 Uncertainties in Future Load Shapes

Uncertainty regarding future demand also affected the FGRS results. Electric Vehicle (EV) and heating load shapes were created for the study based on stakeholder provided data, but it is unclear how representative these shapes are of future load patterns. EV flex-charging profiles were assigned to each Scenario, but these profiles are based only on pilot programs, not widespread use. Figure 6-4 illustrates the generic implementation of Flex EV in the Scenarios and how it impacts demand. The software could only accept a static load profile and had limited ability to model flexible loads. To simulate price responsive charging, the FGRS assumed a BESS-based flex-charging model. The megawatt size was based on 50 percent of the EV charging profile, and four hours of storage. This allowed the BESS flex charging to modify the fixed charging profiles based on market conditions.

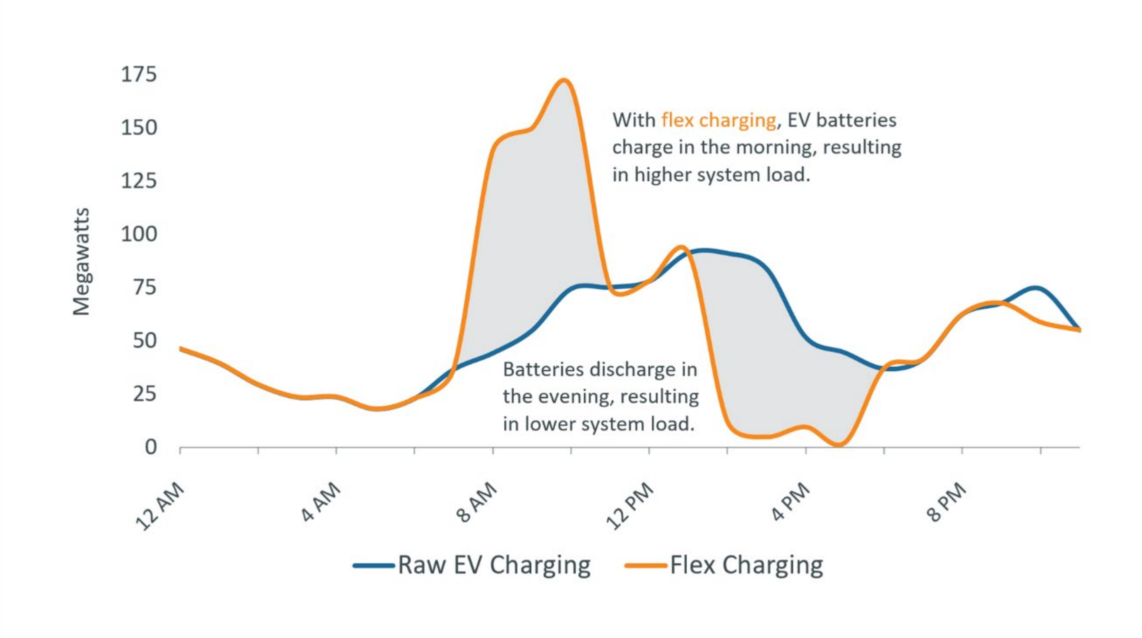

Figure 6-4: Implementation of Flex EV in Production Cost Analysis of FGRS Scenarios

The ISO continues to perform research in this area. In 2021, the ISO worked with a consultant to improve existing light duty electric vehicle profiles and add medium duty electric vehicles to the annual forecast process.

6.4.8 Demand Modeling

Active Demand Response, where customers may curtail their power use at the request of utility providers, has a limited role in this analysis. The electrified heating and transportation load shapes had a large impact on the results of the study, so continued modeling improvement through research will be very important. Many aspects of future electrical load may become more flexible to match future generation variability, but the current software is unable to model this. In addition, the specific shape of this flexibility is currently undefined. The FGRS did not investigate integrating demand response into the dispatch model as an active means of balancing the supply and demand. The study modeled two static tranches of demand response. In a future grid with high penetrations of renewables, it may be beneficial to develop a more dynamic representation of demand response. Post-FGRS, the ISO is beginning to utilize new modeling that should address the roadblocks identified here.

Section 7 : Conclusion

The FGRS built upon findings from the last decade of ISO economic studies, as well as numerous other recent studies of the New England power grid, most notably the Massachusetts 2050 Deep Decarbonization Roadmap Study. The FGRS was also performed in parallel with the ISO's 2050 Transmission Study and the Evaluation of Pathways to a Future Grid study.

The results of the FGRS reveal the need for coordinated and correlated studies of the many different aspects of the power grid to maintain a reliable, economic future grid that meets society's environmental goals. The Scenarios explored in the FGRS pushed and sometimes exceeded the limits of current tools and assumptions.

Electrification of heating and transportation will radically change the demand for electrical power. These changes will make it difficult for energy storage to charge enough to support periods of sustained high demand due to cold weather, as well as periods of low renewable production. Current simulation software seeks to optimize the profits of storage resources over short time periods and assumes this aligns with the reliability needs of the system. The results of the FGRS did not support this assumption. Current software has been developed in an environment where wind, solar, and storage are a small part of the resource mix, instead of the dominant role they will likely play in the future. Results of the FGRS indicate that simulation software requires an overhaul to model variable resources and storage with more granularity and realism.

The production cost results produced important information regarding power system economics, curtailment, emissions, fuel needs, and some high-level transmission observations. All Scenarios experienced some amount of curtailment, where variable resources and imports produced more energy than the system was able to accept. As penetrations of wind and solar increased, more curtailment was observed. Alternative Scenarios containing varying amounts of vehicle-to-grid charging and energy banking with Québec were effective in reducing curtailment. Energy storage will be an important way to maintain reliability of a future grid and will be effective in reducing curtailment of variable resources.

Energy adequacy will continue to be a challenge as the New England grid decarbonizes. In the initial production cost runs, natural gas generators utilized as much gas as they needed. However, the ISO already faces gas constraints in the current system during the winter. Using the ISO's natural gas and liquefied natural gas fuel availability curve for 2025 as an approximation, some Scenarios experienced fuel shortages and would not be able to meet reliability criteria. Though residual fuel oil and distillate fuel oil were sometimes available as alternative fuel sources, another low emission fuel source may be needed in the future. Wind and solar will not always be able to supply energy, and dispatchable generation must be available to support the grid through lulls and droughts of variable energy. These dispatchable generators may not be able to rely on natural gas and may need some other synthetic or renewable fuel to operate during these periods. Nearly any resource and fuel type combination could fit this profile (e.g., co-located renewable and storage, imported hydro, or solar/wind farms operated in a particular way) as long as the resource is dispatchable with enough stored energy to supply the grid.

In the explored Scenarios, emissions generally decreased as penetrations of wind, solar, and energy storage resources increased. Of the four main Scenarios, two reached New England state emission goals, while two did not. Natural gas units were still required to serve load during reliability hours. Alternatives D and E, which retired all fossil fuel generation, saw essentially no carbon dioxide emissions, but also saw some unserved energy when applied to Scenario 3. The retirement of nuclear generation in Alternative C saw increased emissions, as the non-carbon-emitting nuclear generation was primarily replaced by natural gas generation.

High-level transmission analysis identified two problematic regions. In the main Scenarios, northern New England experienced common congestion. Additional congestion was also observed in the SEMA/RI area in Scenario 3. Increasing transmission limits in both regions resulted in decreased production costs and decreased curtailment of resources. As the location of bulk energy supply shifts towards offshore wind sites, significant transmission upgrades will be required to deliver the renewable energy to load centers.

The resource adequacy analysis investigated the ability of future systems to meet load reliably using two analysis methods: RAS and PRAA. The PRAA analysis was found to better model future reliability Scenarios due to a more sophisticated modeling of variable energy resources. Of the main Scenarios, the PRAA analysis indicated that Scenario 0 and Scenario 1 met resource adequacy criteria and had additional load carrying capability (ALCC), Scenario 2 needed some additional generation, and Scenario 3 needed almost 13 GW of additional generation. The RAS analysis found that Scenarios 0, 1, and 2 had ALCC, while Scenario 3 was still short of resources. The reliability timing shifted between Scenarios – while Scenarios 0, 1, and 2 were summer peaking systems, Scenario 3 became a winter peaking system, and reliability hours also appeared in the early morning (rather than occurring around sundown in the other Scenarios).

After analysis found that Scenario 3 needed 13 GW of proxy CTs to meet the reliability criteria, ISO investigated different resource mixes to meet Scenario 3's load. Many mixes were ineffective or impractical – adding energy storage or solar alone did not meet reliability criteria, and the amounts of onshore wind or offshore wind needed to meet criteria are likely infeasible. The most effective resource mixes had a diversity of resource types. Dispatchable resources similar to today's thermal resources were the most efficient at meeting reliability criteria per megawatt added compared to wind, solar, and battery storage. All proxy mix Scenarios had significantly larger reserve margins than today's system.

PRAA analysis was also performed on Alternatives B, C, and D. Alternatives B and D added large amounts of energy storage, which reduced resulting LOLE values. Alternative C, which retired all nuclear units, required maintaining other existing fossil fuel resources. While Scenarios 0, 1, and 2 were sufficiently reliable, procuring and interconnecting the resource mixes needed for the electrification levels of Scenario 3 may be difficult.

Ancillary services analysis found that increasing penetrations of variable resources will require additional flexibility out of the remainder of the system. It will be very difficult to forecast how much power wind and solar resources will produce on a minute-to-minute scale, and system operators will need to be able to respond to sudden changes. Additional regulation or more frequent dispatches will be needed to compensate for the rapid variability of renewable resources.

A system with increased penetrations of wind and solar may also require more reserves due to short-term forecast error. If wind or solar production during a particular day is significantly different than the day-ahead forecast, the system will require sufficient reserves to quickly compensate. A different reserve requirement or product might be necessary to address day-ahead uncertainty. The ancillary services analysis was only able to model reserves from traditional dispatchable generators. In reality, it is plausible that reserves will be provided by energy storage, wind, or solar resources. Increased power production from variable resources will require more system flexibility. If retired dispatchable generators are replaced by new non-dispatchable resources, this could create reliability issues.

The FGRS Phase 1 is a turning point study for our region. Many existing long-term assumptions were called into question as part of this analysis, and results show that the methods by which the ISO and region at large evaluate future grids require an overhaul. The hypothetical future resources and demand mixes assumed by the FGRS are very different from today's system and cannot be fully evaluated with our current tools or assumptions. The FGRS identifies and quantifies many reliability and operation challenges, transmission problems, and ancillary services gaps. Additionally, this analysis identifies areas where gaps of a future grid cannot as of yet be identified or quantified in sufficient detail to suggest a potential path forward.

FGRS Phase 2 will build on the work of FGRS Phase 1. Additionally, the ISO team will continue to investigate the challenges identified in FGRS Phase 1 in the Economic Planning for the Clean Energy Transition (EPCET) study now underway at the ISO.