Generation Fleet Turnover in New England: Modeling Energy Market Impacts

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MODELING RESOURCE ALTERNATIVES

Many regions of the country may soon face a period of accelerated turnover of power system infrastructure. This period of transition is being ushered in by economic and policy factors, including (1) major and potentially sustained changes in the relative prices of competing power generation fuel supplies; (2) deteriorating performance of many older power plants built decades ago; (3) compliance with emerging environmental regulations tied to air and water quality, and the disposal of solid waste; (4) continued pressure to do something about the risk of climate change; and (5) pressure from states and potentially the federal government to substantially increase the development of renewable power and enhance the transmission infrastructure needed to deliver power to load.

As generation infrastructure changes, so will the geographical relationship between power supply and consumption and, consequently, flows on and additions to transmission infrastructure. These changes will have implications for locational prices, generation revenues, power system reliability, and system operations. Given the potential pace of change, utilities, power market participants, industry stakeholders, and regulators and policymakers will benefit from advance thinking on the implications of change for market conditions and power sector pricing.

In this paper we summarize a select set of analyses we carried out related to resource options and infrastructure change in New England, with a focus on certain factors and consequences that will need to be addressed in quantifying and evaluating potential future resource scenarios. Specifically, we extract from our analysis observations focused on key differences between additions of renewables and traditional fossil-fired generation [natural gas combined cycle (NGCC) capacity] from operational and pricing perspectives, and then consider in detail how these additions affect the price and emission impacts of replacing aging coal and oil-fired capacity in New England with either natural gas-fired or renewable resources.

To carry out the analysis, we used the Multi-Area Production Simulation (MAPS) model and our own database on loads, resources, and input prices.[1] In our analysis, we included full representation of the ISO New England (ISO-NE), New York ISO (NYISO), and Ontario systems and portions of the PJM system, and a boundary representation of the resources located in Quebec, New Brunswick and Nova Scotia. Below, we summarize and discuss certain features of the analysis, focusing first on ways in which generation technology choices may affect market outcomes, and then specifically on the implications of replacing aging resources with various combinations of resource alternatives.

TECHNOLOGY CHOICE AFFECTS MARKET OUTCOMES

In choosing which generation resource additions to model, we considered the realities of the New England wholesale market and policy context. The resources available to New England for new capacity are limited. Demand resources may be limited by the availability of sufficient economic opportunities where needed to meet reliability needs. And, for economic and political reasons, few investors seem to have the appetite to pursue new nuclear, coal or oil plants.

[1] MAPS is a simulation model developed and licensed by General Electric.

Given these factors and underlying economics of competing technologies and fuels, natural gas is, and in all likelihood will continue to be, the resource of choice in New England markets. Yet states have pushed hard to integrate New England's vast quantities of on- and off-shore wind resources, and developers and neighboring Canadian provinces are eager to build new transmission interconnections into the Northeast U.S. to tap wind and hydro resources in that region.[2] Therefore, in our modeling we first analyze how wind and natural gas price and operating characteristics translate into power system locational price effects.

Differences in the operational characteristics of wind and natural gas technologies can lead to differences in market outcomes. Gas-fired facilities are dispatchable resources that can be operated whenever desired (within the constraints of ramp rates), but incur operational costs, including fuel and environmental allowances. By contrast, wind power resources are variable resources that produce power when the wind blows, but have (essentially) zero operational costs. These technologies also differ in their capital costs, with wind power costs typically greater than NGCC resources, although such costs do not affect daily market outcomes.

These operational characteristics have important implications for power production, prices and revenues. Figure 1 illustrates these differences by comparing output for wind and gas combined-cycle units against forecast hourly LMPs.[3] As shown in the figure, power output from wind facilities is independent of prices in wholesale markets.[4] Without some form of storage device to hold the power produced by the wind for use at another time, the grid operator can take the power only when produced (or curtail it) and the operator cannot submit bids that reflect the opportunity cost of selling stored power.[5] Because it effectively has no operating costs, wind power thus produces whenever wind conditions permit, which may not always be when prices are highest.

By contrast, fossil-fired facilities are dispatched in economic merit order, with plants with higher costs (or bids) dispatched after lower-cost resources. The pattern of output in Figure 1 reflects this control over output: the gas-fired plant operates at full output during peak demand hours and ramps down to minimum loads (or no output) in off-peak hours as demand declines and output from more costly resources is reduced. Consequently, because dispatchable resources are typically operated only when economics support their use, they tend to operate during periods when market prices are highest.

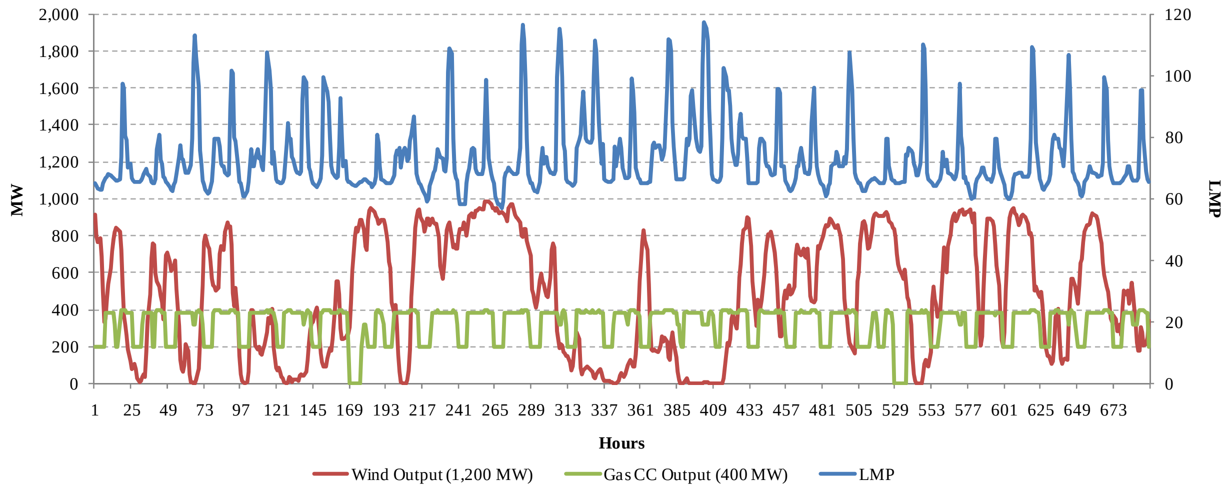
[2] See, for example, Announcement by New England States Committee on Electricity, *Preliminary Responses to Request for Information Identify Over 4,700 MW of Renewable Generation*, February 15, 2011, and Federal Energy Regulatory Commission, Docket No. ER11-2377-000, *Order Accepting Transmission Service Agreement*, issued February 11, 2011, approving a transmission service agreement for a high-voltage transmission line to move power from Hydro Quebec into New England.

[3] The data shown are for February 2020.

[4] Wind output is, however, not entirely random; there are important correlations between typical wind patterns and seasonal and daily variation in load that will affect market outcomes. Because these correlations depend on region-specific meteorological and load conditions, impacts will vary across regions.

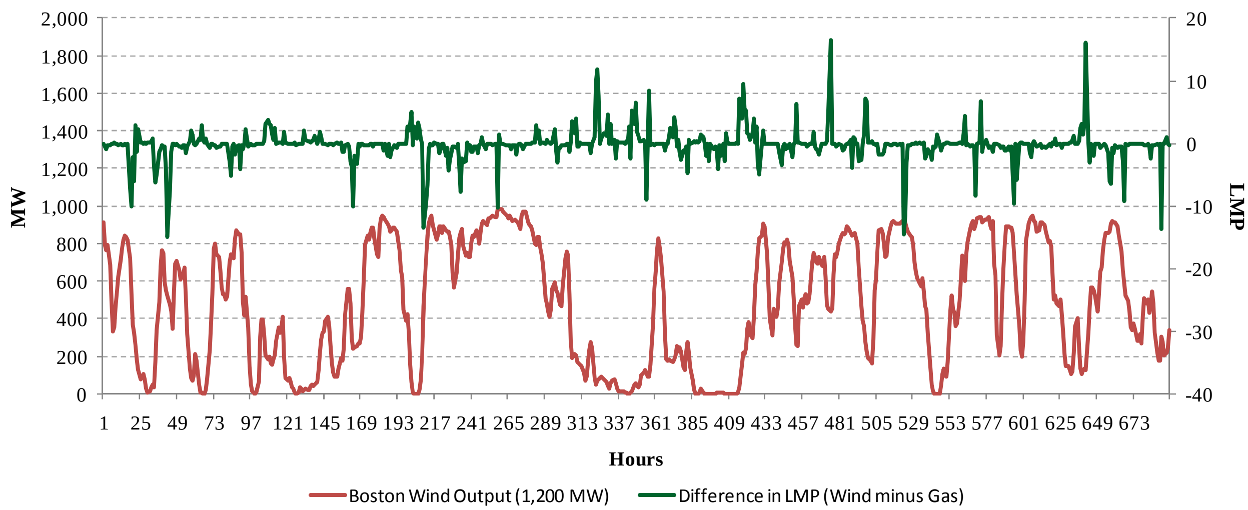
[5] As is the case with any energy technology limited by resource or storage constraints (such as hydropower), producing power at one point in time limits the ability to produce power at some future point in the time when prices might potentially be higher.

Figure 1
Hourly Generation and LMPs, Wind & Gas – February 2020



The operational differences between intermittency and dispatchability illustrated in Figure 1 are a key factor in creating the differences in LMPs between scenarios, as illustrated in Figure 2. The green line [Difference in LMP (Wind minus Gas)] shows the difference in February market prices in two scenarios: one with a 1,200 megawatt (MW) wind facility and the other with a 400 MW NGCC facility (with roughly equivalent annual energy generation). The red line [Boston Wind Output (1,200 MW)] shows the hourly output of the new wind power capacity. The chart suggests that when prices are higher, wind power output tends to be lower than at other times (that is, the green line is greater than zero.) Statistical analysis confirms this negative correlation.[6]

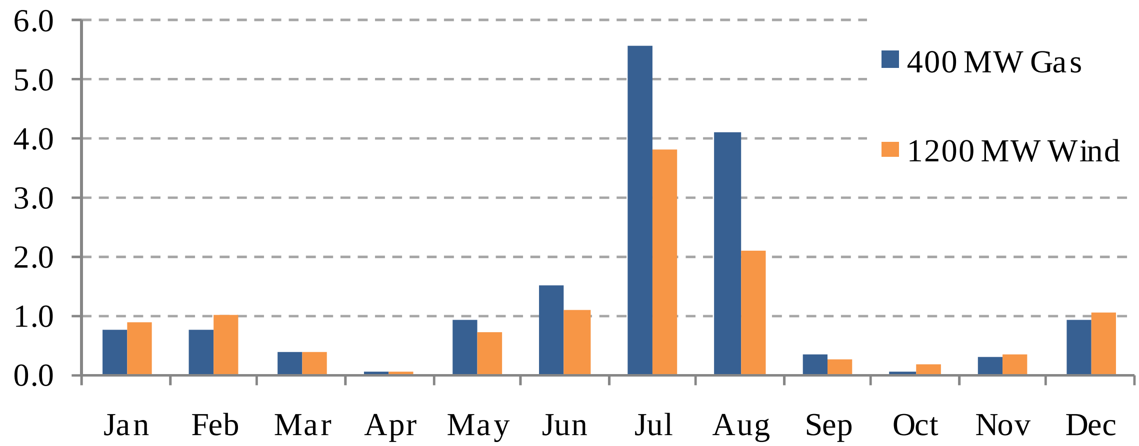
Figure 2
Hourly Wind Power Generation and Differences in LMPs between Wind and Gas Scenarios – February 2020



[6] The correlation between wind power output and the differences in price with wind and gas NGCC entry is - 0.24.

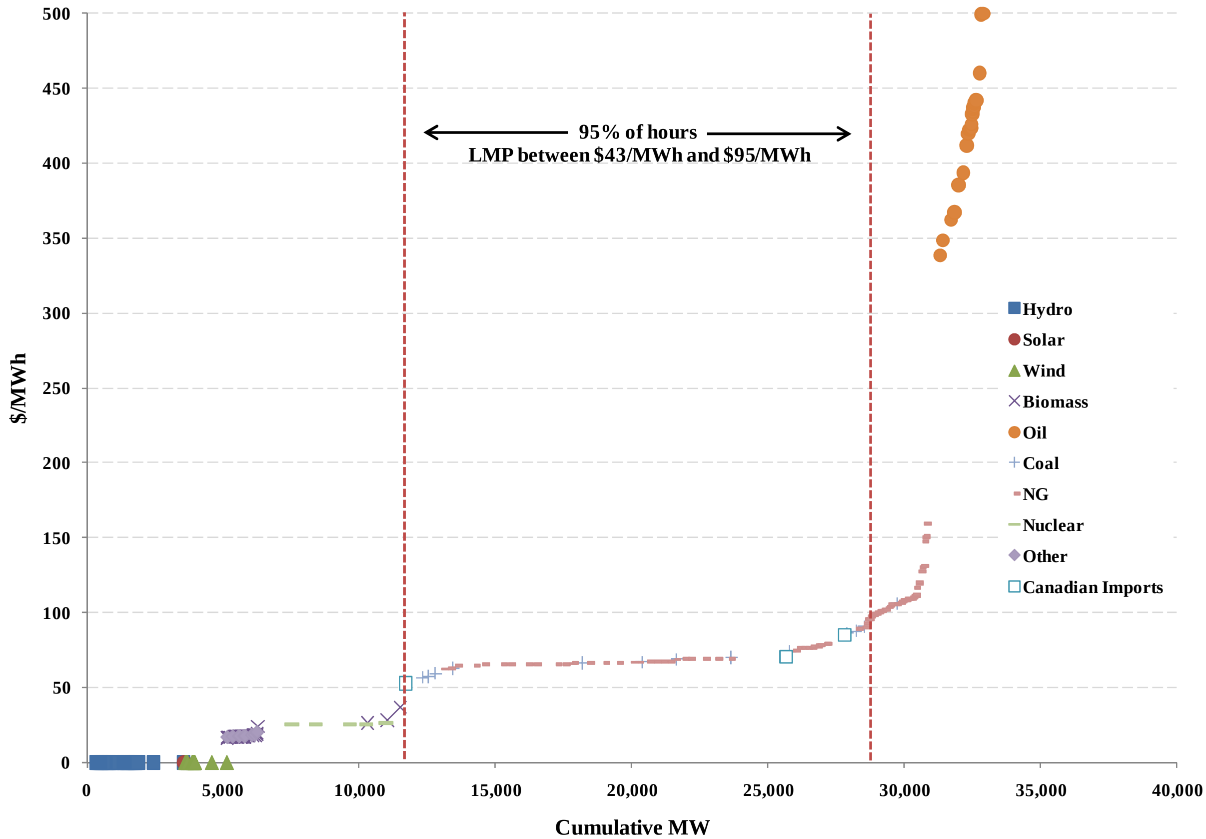
The example provided is for a single month, but the difference in technology pricing is not unique – the LMP impact of adding different technologies also differs across months. Figure 3 illustrates this point by comparing the change in monthly average LMPs arising from introduction of 400 MW of NGCC generation and 1,200 MW of wind power. The figure shows that annual price impacts are driven largely by price effects in summer months when reserve margins are tightest. Most of the reductions in costs and LMPs occur in July and August, which have peak loads 19 and 24 percent, respectively, higher than the peak loads in the non-summer months. In July, the entry of one new gas unit can decrease prices by over $5 per megawatt/hour (MWh), on average, across all hours.

Figure 3
Change in Monthly Average LMP: 400 MW Gas v. 1,200 MW Wind



Of course, while variations in facility output across months may contribute to the large disparity in price impacts across months, the primary driver is the shape of the production supply curve. As Figure 4 shows, the forecast supply curve for New England in 2020 gets much steeper as more resources are called upon to provide output. Consequently, when industry output is high, reducing demand results in a potentially large change in price. By contrast, when output is lower, prices impacts will be more limited. The supply curve in Figure 4 reflects the unique characteristics of the ISO-NE market, which relies heavily upon gas-fired resources with very similar operating costs over many hours of the year. Thus, adding new resources to the market does not dramatically change the marginal resources relied upon for many periods of the year, except during in summer months. Because the shape of supply curves will vary significantly across regions, region-specific assessment is necessary to properly capture the market effects of new entry.

Figure 4
Illustrative Power Generation Supply Curve for ISO New England



Notes: [1] Canadian Imports are modeled as generators with varying capacities and variable costs to mimic actual imports from Canada.
[2] Wind capacity has been derated to 35% of summer rating and solar capacity to 15% of summer rating.

PREPARING FOR THE RETIREMENT OF GENERATION ASSETS

Over the next several years, how well stakeholders understand the differences in operating characteristics and marginal pricing between natural gas and wind-powered generation sources, and are able to evaluate such impacts in the context of state renewable and carbon policy goals, may be increasingly significant. The North American Electric Reliability Corporation (NERC) estimates that up to 76 gigawatts (GW) of fossil-fueled capacity will be retired or derated by 2018.[7] For New England, NERC finds that up to 4 GW of capacity is at risk due to poor market economics and environmentally driven capital investments.[8]

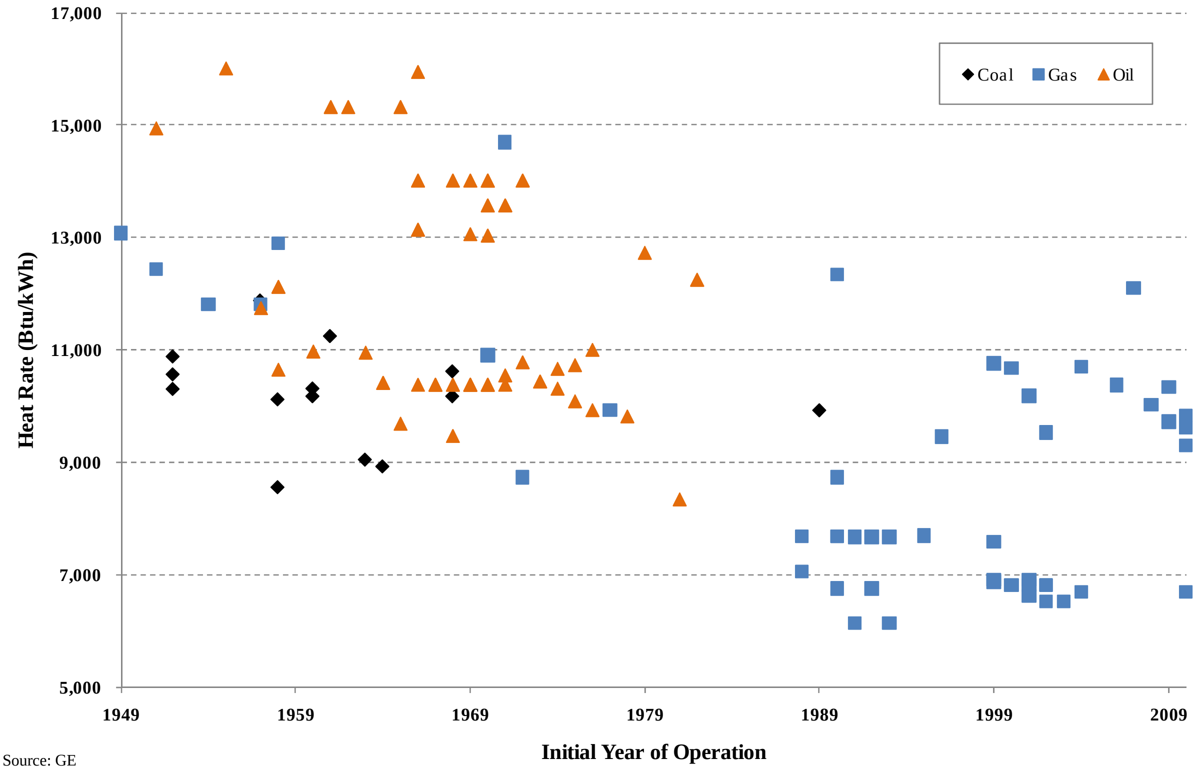
Consistent with these projections, announcements of retiring plants have been emerging steadily over the past year, including in New England. For example, on February 10, 2011, Dominion Resources Services,

[7] North American Electric Reliability Council, *2010 Special Reliability Scenario Assessment: Resource Adequacy Impacts of Potential U.S. Environmental Regulations* (NERC Report), October 2010, page 24.
[8] NERC Report, page 24.

Inc. announced its intention to permanently retire its Salem Harbor power plant by June 2014.[9] When this facility is finally closed, roughly 750 MW of coal- and oil-fired capacity, in the most densely populated load pocket within New England (NEMA/Boston), will be permanently retired. Dominion and industry analysts have cited the combination of impending environmental compliance costs and deteriorating capacity and energy market conditions in New England as key reasons for the retirement.[10]

While New England has substantial new, efficient, combined-cycle natural gas capacity that would be minimally affected by the EPA's emerging air, water, and solid waste rules, it also has a significant number of older, less-efficient fossil-fueled units that are at risk (see Figure 5). Consequently, other aging oil and coal facilities in the region could soon follow in Dominion's footsteps.

Figure 5
2010 Existing New England Power Plant Units
Summary of Heat Rate and Fuel Type by Year of Operation: 1949-2010



Source: GE

Significant turnover of the region's generating fleet would result in substantial price, revenue, and emission impacts. We did not attempt to forecast the retirement of all affected capacity in New England. However, in order to begin to understand the direction and nature of the impacts of competing resource

[9] ISO New England Inc., *Motion for Leave to Respond and Response of ISO New England Inc.*, filing in FERC Docket ER10-2477-001 (ISO Motion), page 1.
[10] Kyle Alspach, "Natural Gas Seen As Cleaner, Cheaper," *Boston Business Journal*, March 4, 2011.

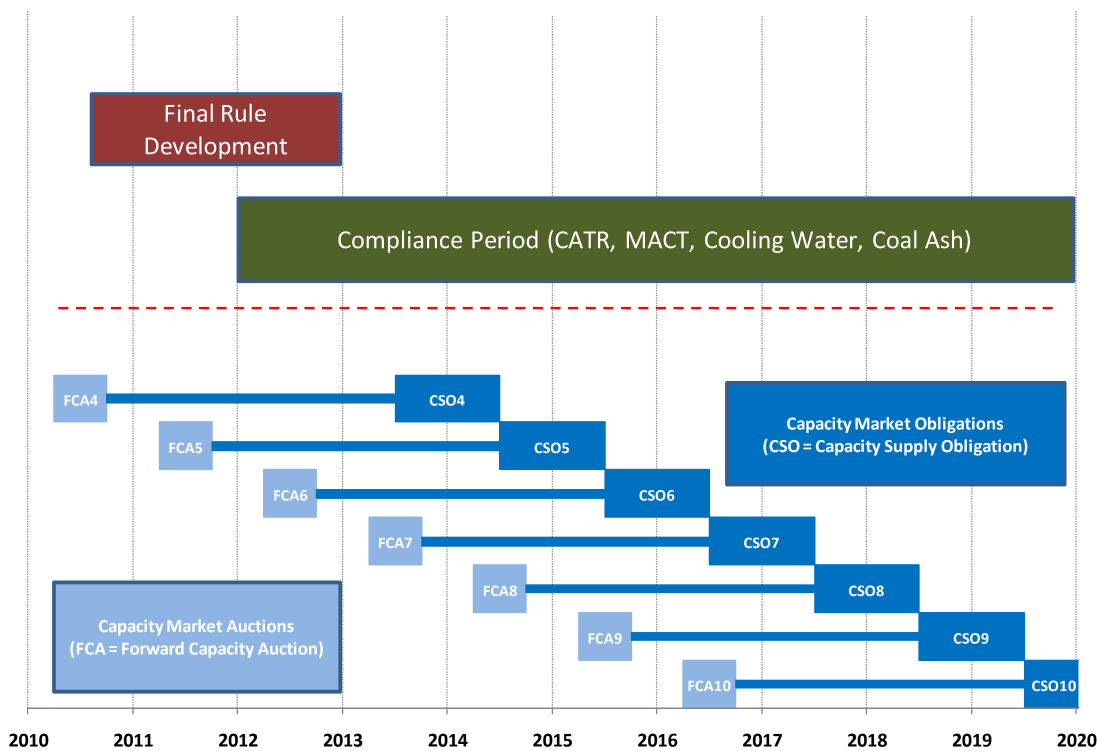
alternatives, we modeled the effects of the one announced plant retirement – Salem Harbor – and evaluated marginal prices and emission impacts of replacing that capacity with various configurations and quantities of natural gas, wind power, and hydro resources.

Competitive Markets and Advanced Planning

Energy infrastructure resource development has been robust in New England. Over the past ten-plus years, the region has reliably added more than 12 GW of generation, nearly 3 GW of demand resources, and enough new transmission virtually to eliminate congestion in the region. Additional infrastructure projects are in development to meet future needs, and New England's forward capacity market has cleared with an excess, at the market floor price, for the past three years.

At first glance, it therefore appears that the region is well-positioned to absorb substantial plant retirements. However, the pace, timing, and location of change matter. The potential for significant retirement of existing oil- and coal-fired capacity within a relatively short period of time means that stakeholders and policymakers in New England need to understand the tradeoffs among resource choices and to consider market impacts. Importantly, the time for these assessments is upon us, since retirement and new capacity development bids in *current* forward capacity auctions – which result in capacity supply commitments in *future* years – will reflect the EPA compliance requirements likely to be in place in the time frame of resulting obligations (see Figure 6).

Figure 6
Time Frame for EPA Compliance Requirements and Regional Capacity Auctions



Resource Choices and Regional Impacts

To begin to understand these tradeoffs, we modeled the combined effects of (1) retiring the coal-fired capacity at Salem Harbor Station, and (2) adding new capacity from either natural gas or renewable resources in increments of either 400 MW or 1,200 MW. Our goal was to gauge the potential magnitude of impacts of competing resource outcomes on emissions and marginal energy prices within New England. For modeling within MAPS, new resources were connected within the same load zone as the retirements (Boston/NEMA). The modeled scenarios include a reference case and five scenarios that assume retirement of coal-fired capacity, and add new capacity in the following quantities and configurations:

Reference case: New England load in 2020, existing resources plus additional renewable resources as needed to meet the region's renewable portfolio standard requirements through 2020.

Scenario 1 (1,200 MW wind): Change the reference case by retiring coal-fired capacity and adding 1,200 MW of wind resources.[11] This scenario involves only the dispatch of the variable wind resource, without specific balancing or backing by another resource type. Consequently, from an annual energy perspective, it is roughly equivalent with Scenarios 2 and 3 (400 MW of capacity each).

Scenario 2 (400 MW wind/hydro): Change the reference case by retiring coal-fired capacity and adding 400 MW of wind resources, but with hydro resources available to fill in up to the 400 MW quantity when wind output is less than that amount.[12]

Scenario 3 (400 MW gas): Change the reference case by retiring coal-fired capacity, and adding 400 MW of NGCC resources.

Scenario 4 (1,200 MW wind/hydro): Same as Scenario 2, except add 1,200 MW of wind/hydro capability instead of 400 MW.

Scenario 5 (1,200 MW gas): Same as Scenario 3, except add 1,200 MW of NGCC instead of 400 MW.

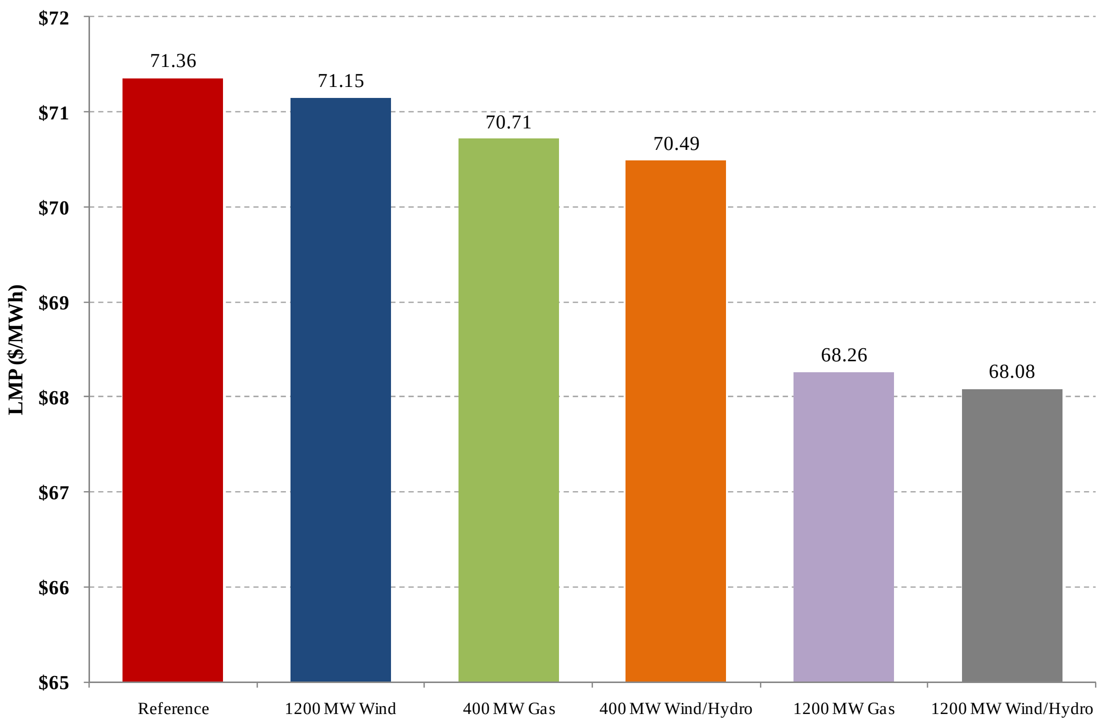
[11] This may be thought of as building a 1,200 MW-capable transmission interconnection into the Boston/NEMA load area, with only the 1,200 MW of wind capacity connected. The quantity of coal-fired capacity retired is equal to the quantity of coal-fired capacity at Salem Harbor Station (roughly 307 MW, summer rating).
[12] This may be thought of as a 400 MW transmission line to which only the wind and hydro resources are connected.

Regional Electricity Market Prices

Removing coal-fired generation from the resource mix increases regional electricity prices. But in every one of the scenarios, adding gas-fired generation or production from wind or wind/hydro resources, the reduction in prices associated with this new generation exceeds the upward price impact of coal unit retirements.[13] Thus, on net, prices decrease in all scenarios.

The magnitude of overall price impacts is shown in Figure 7. Annual load-weighted average marginal price reductions (compared to the reference case) range from $0.21/MWh for the 1,200 MW wind-only scenario, to $3.28/MWh for the 1,200 MW wind/hydro scenario. These price impacts translate into significant energy market cost reductions for the region's electricity consumers. As shown in Figure 8, reduced costs are highest in the 1,200 MW wind/hydro scenario, equal to approximately $449 million in the year 2020.[14] For the 400 MW wind/hydro and natural gas scenarios, and the 1,200 MW intermittent wind scenario, the reduced costs range from $28 million to $119 million (see Figure 8).

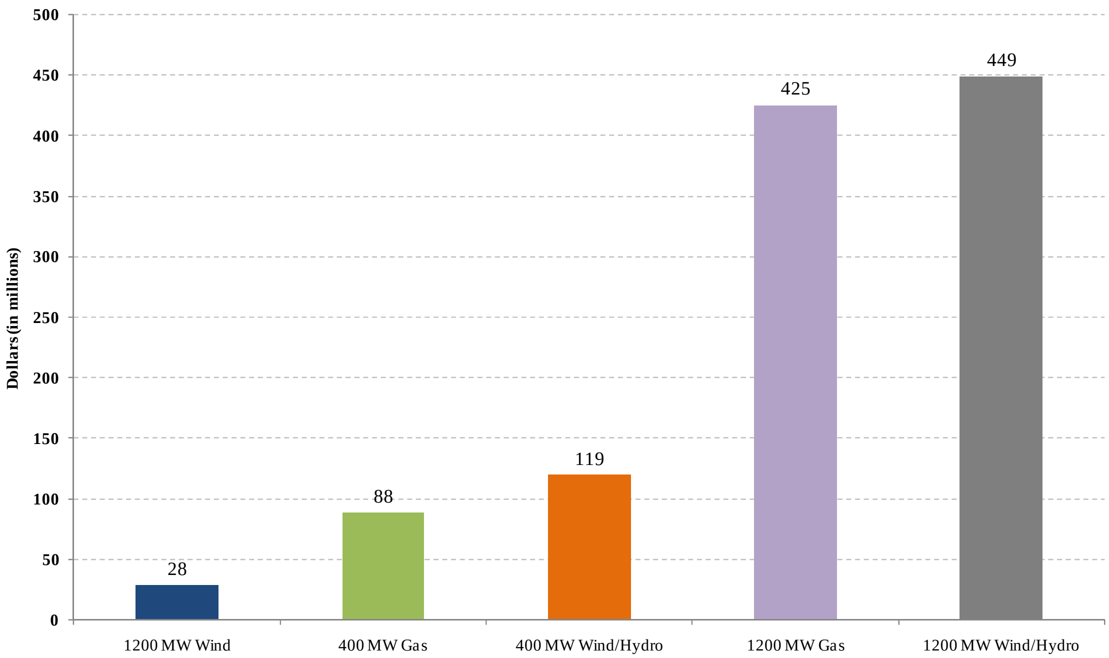
Figure 7
Annual Load-Weighted Average LMPs: New England - 2020



[13] The analysis models only the impact of prices in the energy market; it does not reflect the impact on capacity or reserve market prices associated with either the retirement of Salem Harbor, or the addition of new gas-fired or wind/hydro resources. It also does not reflect the impact on regional transmission pricing should the transmission to interconnect distant wind or hydro resources be collected through the regional tariff (as opposed to being paid for by project developers).

[14] In the long run, decreases in wholesale prices are likely to be fully passed through to consumers, although specifics of consumer's arrangements with retail providers could affect whether cost savings are partially, fully, or more than fully passed through to consumers in the short run.

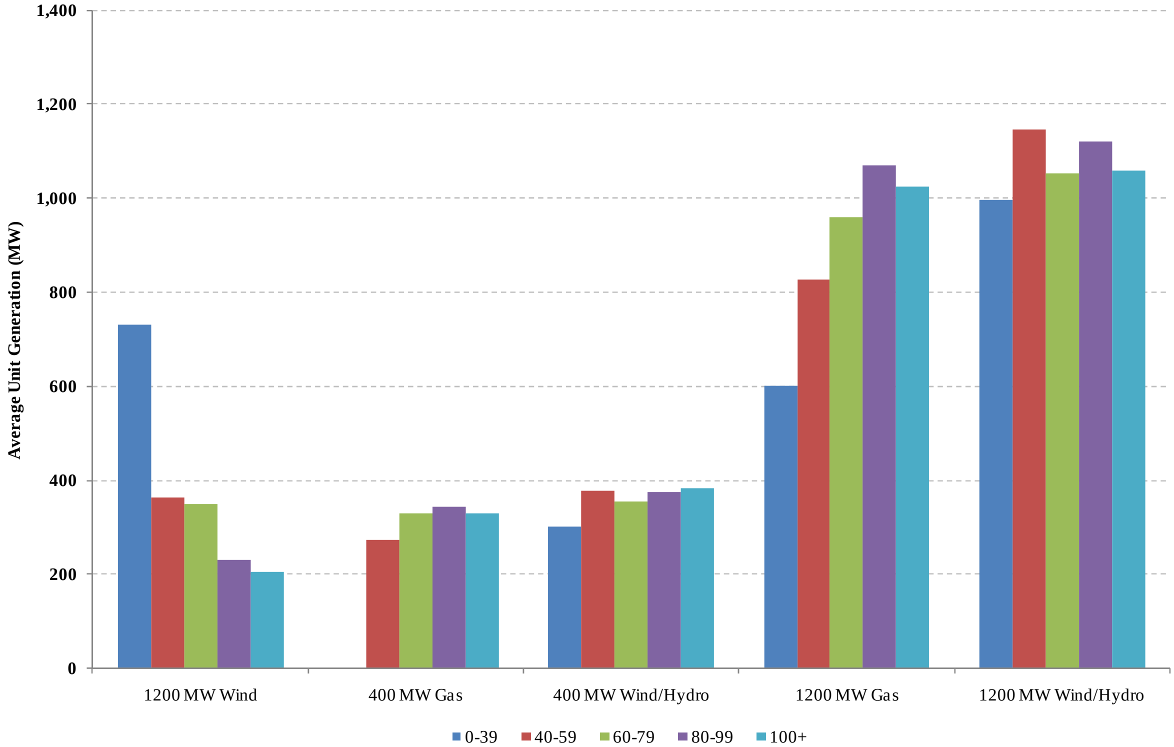
Figure 8
Reduction in Energy Market Costs Compared to Reference Case: New England - 2020



Note:
[1] Costs calculated as the annual sum of area hourly LMPs times area hourly load.

The 1,200 MW wind-only scenario generates the lowest cost reduction of all scenarios, because the variability in wind power output significantly dampens its impact on prices. Because of the limited cost reduction achieved with wind only, mixing wind with some other resource that can balance wind output, particularly where expensive long-distance transmission is required, can further reduce prices. The reduction in prices achieved by this combination reflects the fact that the wind resource is at reduced output in many high-load/high-price hours, as well as the greater output from the wind/hydro combination. In fact, as can be seen in Figure 9, average output for the wind-only scenario is highest in lowest-price hours, and lowest in highest-price hours. It is highly unlikely that a transmission line sized to carry 1,200 MW of wind (when available) would not carry other forms of power when the wind is not blowing, but from the perspective of both price and emission impacts, what fills the remaining space on the line will matter. The example modeled in this analysis – a combined wind/hydro product (Scenarios 2 and 4) – would dramatically increase reductions in energy market costs and emissions (see Figure 9).

Figure 9
Average New Unit Generation by LMP Bucket

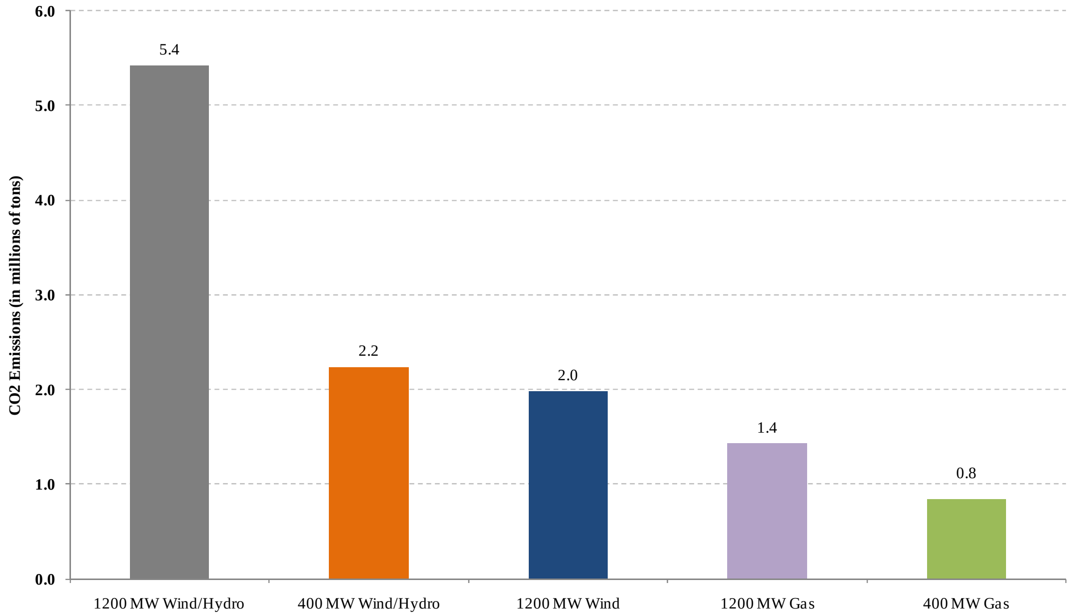


Notes:
[1] New unit generation computed as the simple average of unit generation when hourly, New England, load-weighted LMPs are within the specified ranges.
[2] Unit generation was reported as zero when units were not dispatched and when units were on maintenance. Therefore, results above are a lower bound of average unit generation.

We modeled minor variations in system infrastructure, so the potential for reductions in CO_2 associated with a more significant turnover of the fleet are significant. With respect to CO_2 emissions, the wind-only and combined wind/hydro cases generate the greatest reductions in 2020 relative to the reference scenario, with the NGCC cases leading to smaller reductions.[15] For example, the wind-only and 400 MW wind/hydro scenarios produce reductions of roughly 2 million tons in 2020 relative to the reference case, while in the 1,200 MW wind/hydro scenario, CO_2 emissions lead to reductions more than twice this amount (see Figure 10).

[15] Not all emission changes are associated with the New England region. One effect of increasing low-marginal cost generation in New England is, in fact, to increase exports to New York, relative to the reference case, and to decrease emissions from fossil-fuel generation beyond New England's borders. The emission results reported here represent changes in total dispatch emissions across the full modeled region (i.e., including NYISO, PJM, and Ontario as well as ISO-NE).

Figure 10
CO_2 Reductions from Reference Case: 2020



Note:
[1] CO2 emissions reported as the sum of CO2 emissions for New England, New York, PJM and Ontario.

CONCLUSION

The electric industry faces a period of significant change – change that will have important impacts on power supply operations, diversity, emissions, and prices. Forthcoming EPA regulations and continued expectations of control requirements for CO_2 are likely to lead to reductions in coal- and oil-fired capacity. In New England, it is likely that natural gas and wind resources will take up the slack. In this transition, investors, utilities, developers, and policymakers will need to better understand the revenue, price, cost, emission, and portfolio diversity tradeoffs that come with power system resource options.