Renewable and Clean Energy Scenario Analysis and Mechanisms 2.0 Study

Phase I: Scenario Analysis
Winter 2017

NESCOE
New England States Committee on Electricity

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I. Introduction and Executive Summary

This report presents an economic analysis of various hypothetical clean energy futures in New England,[1] and is the first phase of a two-phase study. Phase I shows the potential implications of various hypothetical renewable and clean energy futures on existing and new resources in New England, and ultimately on the consumers who pay for them.[2] Phase II will examine, in the context of the Phase I hypothetical futures, various mechanisms that states could use to achieve certain policy objectives and the associated consumer costs. Together, Phase I and II of the study is intended to inform policymakers' consideration of potential mechanisms through which states could execute energy and environmental objectives and their consumer cost implications.[3] This two-phase study is one of several pieces of information that may assist states' consideration of means to achieve state energy and environmental laws.[4]

London Economics International ("LEI") performed the economic modeling that is at the core of this Phase I report. LEI analyzed New England wholesale electric energy and capacity market dynamics in two future years - 2025 and 2030 - under various hypothetical future market conditions that NESCOE defined. Specifically, LEI estimated the going-forward costs and future electricity market revenues for existing and new generation resources in New England with a focus on renewable and clean energy resources.[5] Importantly, the market revenue

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1 In December 2015, NESCOE's *Mechanisms to Support Public Policy Resources in the New England States* (2015 Mechanisms Whitepaper) identified a range of mechanisms, such as Renewable Portfolio Standards, clean energy standards, and long-term contracting, available to states to support resources capable of satisfying various objectives, such as. It described various mechanisms' mechanics, as well their interaction with New England's competitive wholesale markets and some legal and regulatory issues. *See* http://nescoe.com/wp-content/uploads/2015/12/PublicPolicyMechanisms_December2015.pdf.

2 Renewable energy is defined by common eligibility for Class I Renewable Portfolio Standard ("RPS") among the six New England states and, at utility scale, generally includes on- and off-shore wind, solar, small hydro, and biomass. Clean energy is defined as production from nuclear resources and imports from neighboring systems powered predominantly by large-scale hydroelectricity.

3 An electricity customer's bill includes three main components: (1) energy supply costs, (2) transmission costs, and (3) distribution costs. This Phase I: Scenario Analysis report is focused on wholesale market impacts, which directly affect the energy supply cost component of a customer's bill. As discussed further in Section V. Study Approach, wholesale market prices include both the energy and capacity market.

4 In June 2016, the New England Power Pool ("NEPOOL"), an advisory body of New England energy stakeholders, commenced a conversation about whether it could identify potential market solutions that could accommodate state laws. That exploratory effort remains underway. For more information, *see* http://www.nepool.com/IMAPP.php. Another piece of information that may inform thinking on markets and policies is an ISO New England ("ISO-NE") *Economic Study of Markets and Planning*, which NEPOOL requested and defined. For that ISO-NE study, the NEPOOL End User Sector defined the clean energy future assumptions; those assumptions do not conform to the clean energy future assumptions NESCOE identified for this study. That work also remains underway. *See* http://www.nepool.com/2016_Scenario_Analysis.php.

5 The going forward cost estimates were based on publicly available information. Wholesale market revenues were based on an economic model of ISO-NE's energy and capacity markets, but do not include ancillary services. Going forward costs and market revenues were averaged by resource type. The impacts

estimates under the hypothetical scenarios are directionally indicative, not precise predictions. For example, they were developed without taking into account the impact of certain market rules on new and existing resources, including the Minimum Offer Price Rule ("MOPR").[6] Finally, LEI estimated the amount of "missing money" for each resource type – i.e., the amount by which a resource's *costs* exceed its forecasted wholesale electricity market *revenues*. LEI also examined power sector air emissions under a range of future scenarios.

For this study, NESCOE:

1) Designed the set of hypothetical resource and infrastructure expansion scenarios,

2) Specified the assumptions, and

3) Prepared this Phase I Report.

LEI conducted the modeling and provided the results to NESCOE.

NESCOE presents the results of LEI's analysis in this Phase I report and also offers context and some observations. This report is not a plan or a recommendation. It simply provides information about a set of hypothetical scenarios based on a host of assumptions. It should be viewed accordingly, and critically.

Each hypothetical future energy system scenario added or subtracted varying amounts of renewable and clean energy resources to the region's power system. These assumed amounts of clean power influence wholesale electricity market prices and competition among resource types.

Ultimately, the analysis provides estimates of the amount of "missing money" that generation resources may need to: 1) enable New England to meet the hypothetical state clean energy and renewable requirements, and 2) maintain reliable electric service at the lowest possible consumer cost over the long-term. The results are directionally consistent with other studies.[7]

When LEI added renewable and clean energy resources to its model at NESCOE's request, it found that market energy prices are lower than the prices under the Base Case or status quo. In addition, capacity market prices were found to decline temporarily but rebound in later years. The decline in capacity prices is the result of excess supply in the capacity market, which is affected by, among other things, not applying the MOPR, low peak load growth, and few retirements. Together, energy and capacity market price declines cause resources' revenue to decrease. The Phase I results also show competitive dynamics in the energy market by and between existing and new resources and the impacts on power sector carbon dioxide emissions.

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of certain wholesale market rules, including the seven-year capacity price lock, shortage event performance incentives, and energy market negative pricing were beyond the scope of the analysis.

6 This rule was designed by the ISO-NE Internal Market Monitor to protect developers of competing supply resources from the effects of buyer-side market power. A buyer has market power if it can compel suppliers to reduce price below the level that would emerge in a competitive market. For more information about the Minimum Offer Price Rule ("MOPR") and the associated exemption for renewable technology resources, see *ISO New England Inc. and New England Power Pool Participants Committee*, 158 FERC ¶ 61,138 (2017). On the other hand, counting new renewable and clean energy resources which are required to meet state emission statutes avoids the over procurement of capacity and reduces the reliance on natural gas resources, natural gas capacity constraints and associated reliability concerns.

7 *See*, for example, initial draft results from NEPOOL's 2016 Economic Study: Scenario Analysis, available at http://www.nepool.com/uploads/IMAPP_20161110_2016_economic_study_draft_results.pdf.

II. Study Limitations

This study, and LEI's modeling, provides *directionally indicative* information about a range of hypothetical scenarios. It is not a plan, and it is a not a collective or individual state view of or preference about the future.

Given the hypothetical nature of the input assumptions for the scenarios, LEI's modeling is intended to be illustrative rather than predictive or precise. It is based on many assumptions, any one or more of which history may prove wrong to varying degrees.

The costs LEI's model identifies are based on assumptions and therefore should not be interpreted as an actual price tag. LEI was not asked to consider the total costs of any of the investment in the hypothetical scenarios. The total costs of an investment are the costs that would emerge in a competitive solicitation, as the result of a negotiation, or otherwise reflect actual project costs.

LEI's model assesses different hypothetical scenarios, but cannot predict the future given there are many uncertainties in electricity markets.[8] Rather, any analysis in this study assumes that policymakers will apply judgment to the assumptions in each of the hypothetical scenarios and their assessment about future conditions.

In addition, the study does *not* attempt to:

- Precisely forecast the timing of future generator retirements, or infrastructure development.
- Evaluate cost-effectiveness under an avoided cost approach.
- Optimize the level, timing, or location of renewable and clean energy resources.
- Suggest winners or losers.

This study should be viewed accordingly, and critically.

NESCOE welcomes from market participants or others any facts or data that clarify, correct, or should be considered in reviewing the study results.

8 While the model uses mathematical logic to select the least cost portfolio of resources to meet forecasted demand based on a host of assumptions, the model cannot predict the future. For more information regarding the limitations of the study, see page 25.

III. Phase I Observations

1. **When the LEI model adds *new* renewable generating resources or additional clean energy imports to the New England system with zero or very low marginal costs, those added resources have the effect of decreasing the amount of money that all resources earn from New England's capacity and energy markets.[9]**

   The reduced flow of money that resources earn from the regional markets impacts the region's newer natural gas-fired resources because those resources are financially dependent on payments provided by participation in the regional capacity market.[10] Over time, the modeling results suggest that adding new renewable generating resources or additional clean energy imports to the New England system would create "missing money" for new, relatively high capacity factor natural gas resources, while some of the low capacity factor oil resources remain profitable. The region's biomass and refuse plants' "missing money" also increases significantly.[11]

   Renewable Resources

   The modeling results also indicated that market revenues would be insufficient to cover costs for *existing* public policy resources, i.e., clean energy resources that satisfy the requirements of state laws. Note, however, that the economic impact of mechanisms that support public policy resources, like power purchase agreements and Renewable Energy Certificates ("RECs"), were not included in this scenario analysis. Phase I: Scenario Analysis is designed to show market interactions and resource economics without the impact of mechanisms. Mechanisms to support public policy resources are the focus of Phase II of the study.

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9 This observation assumes the MOPR is not in effect and that the full capacity value of the assumed renewable and clean energy resources is counted toward the region's resource adequacy targets. Had the MOPR been applied to the capacity market modeling, new renewable and clean energy resources would have been less likely to have been selected by the capacity market and their full contributions to the region's resource adequacy may not have been counted. Applying the MOPR in the modeling would have led to higher capacity market prices and lower missing money estimates for existing resources, all other things being equal. On the other hand, counting new renewable and clean energy resources which are required to meet state emission statutes avoids the over procurement of capacity and reduces the reliance on natural gas resources and the associated natural gas capacity constraints and reliability concerns. How to resolve this tension is part of the ongoing Integrating Markets and Public Policies ("IMAPP") process and Phase II of this study.

10 As described in Section V. Study Approach, below, the energy market governs the production of, or the ability to instantaneously produce, electric energy. To ensure the region has an adequate supply of resources to meet forecasted future electricity demand, the capacity market procures obligations to participate in the energy market every day. As shown in Section VI. Study Results, capacity market results are especially sensitive, by design, to the amount of supply (or oversupply) resources in the region. For more information, see also https://www.iso-ne.com/about/what-we-do/three-roles/administering-markets.

11 These plants have significant "missing money" in the base case. Some of these plants are Class I or II eligible in some of the New England states. This study does not analyze whether the Renewable Energy Certificate ("REC") market is sufficient to make these plants profitable.

Gas-Fired Resources

The study's assumed addition of renewable and clean energy resources results in an excess supply of generation resources through 2025, relative to the level needed to maintain reliable electric system operation, which will lower capacity prices. By 2030, in all scenarios, the model shows that capacity market prices are projected to return to a higher level that would provide sufficient revenues to *existing* gas-fired resources. This suggests that any price-reducing effect is temporary and related to the timing of entry of new renewable and clean energy resources. However, in the model, even with this projected rise in capacity market prices, *new* gas-fired resources will still fall short of net revenues needed to operate at a profit.[12]

2. **Under Base Case load conditions,[13] if the region adds more than 25,000,000 MWh (annually) of *new* renewable resources and/or clean energy imports by 2025, *existing* renewable and clean energy resources produce less power.[14]**

In the scenarios that add the most renewable and clean energy resources, the *new* renewable and clean energy resources begin to displace *existing* renewable and clean energy resources.[15] The resource types that are affected first are biomass, nuclear, and on-shore wind. The biomass and nuclear resources, while having lower operating costs than natural gas-fired resources, are more expensive than other renewable and clean energy resources.[16] Thus, competition from new renewable and clean energy resources causes existing biomass and nuclear resources to produce less energy. Some of the existing on-shore wind resource produces less energy because it is located in a transmission-constrained portion of the New England system.

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12 The modeling results provide only a general indication of this trend. Estimating specific amounts associated with this observation are beyond the scope of the study. Such an analysis would include additional capacity market features including the so-called seven-year price lock for new resources; shortage event performance incentives; and the MOPR, discussed above.

13 The assumed load forecast in all scenarios includes regional energy efficiency programs and distributed generation impacts consistent with the 2016 ISO-NE Capacity Energy Loads and Transmission ("CELT") Report's load forecast net of passive demand resources and behind-the-meter solar photovoltaics.

14 For reference, the study assumes the New England power system serves approximately 125,000,000 MWh in 2025 and 123,000,000 MWh in 2030. Thus, the 25,000,000 MWh threshold represents approximately 20% of regional energy demand being served by new renewable and clean energy resources. *See* Section V. for a description of the resource and infrastructure expansion assumptions for each scenario and Section VI.B. at 36-38.

15 For more explanation of competition in the energy market, see Section V.B. Also, see ISO New England's explanation of its role administering the various wholesale electricity markets at https://www.iso-ne.com/about/what-we-do/three-roles/administering-markets. This finding, as all information presented in this report, is based on a host of assumptions, including the future demand for electricity and amount of energy traded with neighboring electric systems. Under different assumptions, the competitive dynamics of the wholesale market may be different.

16 This statement that some resources are more expensive than others is based on: (1) the study's assumptions and (2) market participants' energy market supply offers consisting of only the costs to provide an additional MWh of energy in the short term (i.e., so-called short-run marginal costs).

The first time the model shows that new renewable and clean resources cause existing renewable and clean resources to produce less energy is in the Expanded Scenario in 2030.[17] This scenario assumes approximately 26,000,000 MWh from new renewable resources. The Aggressive Scenario and the Combined Scenario, which add approximately 28,000,000 MWh and 36,000,000 MWh in 2025 respectively, have an even greater impact on biomass, nuclear, and existing on-shore wind resource production. For example, in the Combined Scenario, nuclear resources' production decreased by 14% in 2025 and by 31% in 2030 relative to the Base Case.[18] As a point of comparison, in the Base Case Scenario, nuclear resources' capacity factor was 91%. However, in Combined Scenario, nuclear resources' capacity factor declined to 78% in 2025 and to 63% in 2030.[19] The nuclear production decline is due to a combination of more low-priced energy in the scenarios and light load conditions (portions of the year when demand for electricity is relatively lower). Nuclear resources cannot cycle on and off very easily due to long minimum on and off time constraints. The economic model, which operates as if it has perfect foresight, selects nuclear resources to remain off for longer periods when they are turned off, particularly around maintenance outages in the spring and fall. Of course, actual market conditions and resource operations in 2025 and 2030 may differ from the economic modeling results.

3. **In the Base Case, if New England maintains *current* RPS targets and does not add transmission for new on-shore wind, the modeling shows that there will not be enough renewable resources to satisfy the states' aggregated RPS targets in 2025 and 2030.**

   Specifically, this observation assumes that: (a) the states' aggregated class 1 RPS target is approximately 26.28% in 2025 and 28.71% in 2030, (b) new renewable resources will mostly be *new* on-shore wind,[20] (c) the existing transmission system in Maine cannot support enough new on-shore wind to enable the region's aggregated RPS compliance, and (d) the level of RECs imported from neighboring systems will be consistent with historical trends. Without new transmission in Maine to support *new* on-shore wind

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17 *See* Section V. Study Approach for a full description of the hypothetical future resource and infrastructure expansion scenarios. *See also* Figure 11, on page 37, which presents this information graphically.

18 The Combined Renewable and Clean Energy Scenario adds 1,000 MW of clean energy imports, 1,000 MW solar PV, 4,250 MW on-shore wind, and 2,000 MW off-shore wind by 2025 (with an additional 1,250 MW solar PV, 5,500 MW on-shore wind, and 2,500 MW off-shore wind by 2030) to the resources cleared through FCA 10 and assumed Base Case additions. All values are expressed in terms of nameplate capacity. *See* Section V. Study Approach for more information.

19 The assumed load forecast for 2025 is approximately 125,000,000 MWh and for 2030 is 123,000,000 MWh. Thus, the load forecast declines by 1.6% from 2025 to 2030, which may also contribute to resource production declines observed in the study.

20 The Base Case represents an extension of the status quo. At the time the assumptions were finalized, the predominant renewable resources in the interconnection queue were on-shore wind resources. For more information on the study approach and assumptions, and the Base Case results in particular, see the Base Case Results presentation in Appendix B, also available at http://nescoe.com/wp-content/uploads/2016/11/Mechanisms_BaseCase_November2016.pdf.

resource, system operators would need to curtail certain Maine-based wind resources to allow other wind resources to run. This observation of the modeling results assumes that new renewable resources will largely be on-shore wind; there are of course other technologies and means to satisfy RPS requirements that do not require transmission. Importantly, the Base Case scenario does *not* suggest that the only way to satisfy renewable and clean energy objectives is by increasing the amount of on-shore wind that requires new transmission.

4. **If New England does not build new transmission to allow *new* on-shore wind resources to move power to population centers, both *new and existing* on-shore wind resources will operate less often and earn less revenue in 2025 and 2030.**[21]

The current transmission system can accommodate a limited amount of power transfers between where most of New England's wind power is generated and most electricity customers live. Transmission constraints between Maine and population centers result in congestion and curtailments for existing and new on-shore wind resources. This congestion requires existing and new resources to compete against one another for limited space on the existing transmission system (known as "headroom"). Without additional transmission upgrades a lack of transmission headroom reduces opportunities for new on-shore wind resources to sell power and earn revenues. Reduced revenue opportunities would increase the need to support new on-shore wind resources through other means, such as long-term contracts or another mechanism, *if* states wish to increase the amount of new on-shore wind in the region's power mix.[22] This scenario does *not* suggest that the only way to satisfy renewable and clean energy objectives is by increasing the amount of on-shore wind that requires new transmission.

Some of the study's scenarios assume consumers would pay for the costs of transmission reinforcement that may be needed for the system to support new on-shore wind resources pursuant to a voluntary agreement by one or more states. This could be through an Elective Transmission Upgrade, for example.[23] In other scenarios, the study assumes the developers of a new on-shore wind resource would pay for transmission costs as part of its interconnection agreement and thus look to recoup those costs in the revenues it receives once operating.[24] Without new transmission paid for by consumers under a

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[21] The Base Case scenario adds 1,180 MW of new on-shore wind by 2025. The Expanded RPS 35%-40% scenario adds (including Base Case additions) 4,000 MW by 2025 and 4,750 MW by 2030 of new on-shore wind. The More Aggressive RPS 40%-45% scenario and Combined Renewable and Clean Energy scenario add (including Base Case additions) 5,425 MW by 2025 and 6,675 MW by 2030 of new on-shore wind.

[22] Long-term contracts are also commonly called Power Purchase Agreements ("PPA"). *See also* 2015 Mechanisms Whitepaper at Section IV. Long-Term Contracts.

[23] Elective Transmission Upgrades are transmission lines that are voluntarily funded by project parties. For more information, *see* https://www.iso-ne.com/committees/key-projects/implemented/elective-transmission-upgrades.

[24] The transmission costs assumed in this study are associated with hypothetical transmission upgrades that would enable new on-shore wind resources to deliver power to customers across the region. This does not include the costs for transmission upgrades specifically designed to enable the resource to interconnect to the system. See Appendix A for more information on the study's assumed hypothetical transmission

voluntary state agreement approach, the modeling shows that new on-shore wind would not earn enough money from the markets plus programs such as RPS requirements to be profitable.[25]

5. **Under every hypothetical scenario, LEI's analysis projects that nuclear units, existing oil combustion turbines, oil internal combustion turbines, oil steam, and pumped storage remain profitable in 2025 and 2030.[26]**

All resources earn less revenue in scenarios that add the most renewable and clean energy resources; however, even under the scenario with the most new renewable resources and clean energy imports (described above), nuclear units, existing gas/oil combustion turbines, existing gas/oil internal combustion turbines, oil combustion turbines, oil internal combustion turbines, oil steam, pumped storage, and gas/oil steam are still projected to remain operating.[27] Under that scenario, nuclear units produce substantially less power in 2025 and 2030 and therefore earn less revenue in the energy markets and their presumed equity returns are reduced.[28] The oil units have very low capacity factors in all scenarios but continue to remain profitable by virtue of the revenues from the capacity market.

Notably, LEI's estimate of going forward costs for existing resources, like nuclear resources, does not explicitly include equity returns or significant capital expenditures. LEI's approach for going forward costs is based on the economic theory that an existing resource would not include so-called "avoidable" costs in its capacity market supply offer. Importantly, LEI's model does not reflect resource owners' actual business judgment, which could result in different outcomes such as plant retirements because of inadequate equity returns or the need for unanticipated capital expenditure.[29]

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infrastructure for delivering new on-shore wind resource output and Section VI.C.1. for more information on how the costs of such transmission are incorporated into the study results.

25 Mechanisms to support public policy resources, like power purchase agreements, are analyzed in Phase II of the study.

26 The study did not explicitly evaluate nuclear resources' going forward costs and market revenues for other years; the Study only examined hypothetical future years 2025 and 2030. Building on the results from the Forward Capacity Auction for 2019-2020, the capacity market model economically retired any resource that with going forward costs in excess of its energy and capacity market revenues for three consecutive years.

27 For more information about the study's assumptions and market models, see the Base Case Results in Appendix B, at 18-29, also available at http://nescoe.com/wp-content/uploads/2016/11/Mechanisms_BaseCase_November2016.pdf.

28 The More Aggressive RPS 40%-45% Scenarios added 1,000 MW solar PV, 4,250 MW on-shore wind, and 2,000 MW off-shore wind by 2025 (1,250 MW solar PV, 5,500 MW on-shore wind, and 2,500 MW off-shore wind by 2030) in addition to the resources cleared through FCA 10 and assumed Base Case additions. The Combined Renewable and Clean Energy Scenario adds an additional 1,000 MW of clean energy imports to the More Aggressive RPS 40%-45% Scenario's capacity additions. All values are expressed in terms of nameplate capacity. *See* Section V. Study Approach for more information.

29 *See also* Limitations of Modeling Results on page 25.

6. **If New England's nuclear resources retire and/or if New England has only enough renewable resources to meet current RPS levels, New England's emissions will increase significantly.**

   Carbon dioxide emissions rise from approximately twenty five (25) million short tons in the Base Case to nearly forty (40) million short tons in the nuclear retirement scenarios. The rise in emissions would significantly exceed New England's share of Regional Greenhouse Gas Initiative ("RGGI") targets.[30] RGGI is the cap-and-trade program that enables carbon emission allowances to be traded among participating states (which also includes Delaware, New York, and Maryland) to achieve reductions at least cost. To achieve future RGGI power sector carbon emissions targets, which are assumed to continue to tighten at the current pace beyond 2020 in future program reviews, New England would require enough renewable resources to meet current RPS levels *plus* 1,000 MW or more of clean energy imports (other than from NY) or power sector carbon dioxide emissions reductions would need to occur in RGGI states outside New England.

7. **Different types of renewable and clean energy resources have different effects on wholesale electricity costs and emissions.**

   Hydropower and nuclear resources displace higher cost and higher carbon-emitting resources more often than do weather-dependent resources such as wind and solar. Hydropower and nuclear resources are generally available during the times of day and periods of the year when consumers use the most power. As a consequence, hydropower and nuclear resources generally have the greatest positive effect on wholesale electricity costs and emissions.[31]

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30 The Regional Greenhouse Gas Initiative ("RGGI") 2016-2017 Program Review process also includes power sector modeling. RGGI's modeling has different objectives, geographic scope, modeling tools, and analytical approach than the modeling that informs this study. While some assumptions are common (e.g., the ISO-NE load forecast), the two analyses are not directly comparable.

31 These resource types may have other relevant characteristics that may present challenges, however. For example, nuclear units need to refuel approximately every 18 months and incremental imported hydropower requires transmission development.

IV. Historical Context

In New England, the Independent System Operator ("ISO-NE") identifies generating resources that will serve New England consumers at the lowest cost through a competitive system that is deliberately fuel neutral. ISO-NE's competitive auction process was designed to select resources based only on their costs. It is therefore generally indifferent to resources' environmental attributes and to the energy and environmental requirements of state laws.[32]

In the 1990s, policymakers in the New England states expressed a number of rationales to support this structure, in some cases explicitly stating the goals in legislation or orders.[33] Among the goals most often cited were:

- Market mechanisms are preferred over regulation to set price where viable markets exist.
- Risks of business decisions should fall on investors rather than consumers.
- Consumers' needs and preferences should be met with lowest costs.
- Electric industry restructuring should not diminish environmental quality, compromise energy efficiency, or jeopardize reliability.

The composition and attributes of the generation fleet that supplies New England consumers with their electricity has changed significantly since the 1990s.[34] Information from ISO-NE, the U.S. Energy Information Administration, and other publicly available data illustrate that:

- The proportion of generation added by non-regulated players, be it independent producers or the unregulated subsidiaries of utilities, rose dramatically in the 1990s prior to retail restructuring.
- In New England, natural-gas fired generation has been the dominant source of new capacity additions (and electric energy production) annually over the last twenty years, leading to increased reliance overall on natural gas to supply the region's electric power load, although renewables have also increased with support from the New England states.
- Given that the fuel mix in New England has gradually been reshaped by new additions of more efficient combined cycle natural gas plants, as well as by smaller amounts of non-emitting renewable sources of generation, the region's emissions of both conventional pollutants and carbon from power plants have fallen over time. (However, because of natural gas

32 In response to states' request, ISO-NE recognizes in system planning some resources that are in the region's resource mix as a result of states' laws, such as through an Energy Efficiency Forecast and a Distributed Generation Forecast.

33 A review of the history of electric industry restructuring is available here: http://nescoe.com/resource-center/restructuring-dec2015/.

34 *Id.*

pipeline constraints during winter months, and the region's resulting reliance on fuel oil, emissions have risen over the past few winters.)[35]

- Average heat rates for the region's natural gas generating fleet, an industry measure of operational efficiency in converting fuel into electricity, improved as more efficient combined cycle plants have replaced less efficient, single-cycle steam units.

At the time of restructuring and the transition to a regional market, policymakers in most of the New England states also established RPS requirements to achieve specific levels of renewable energy penetration. RPS levels are typically set by statute and in proportion to a state's total electricity sales. States generally set modest levels in early years that escalated over time. RPS programs use competitive market forces to identify the level of economic support necessary to achieve the state's objectives. States also generally limited RPS program costs through a cost cap feature called an alternative compliance payment ("ACP"), discussed further below.

In New England, renewable energy resource development faces several challenges. One challenge is the ability to finance and develop new renewable resources based solely on wholesale market-based electricity and REC revenues. To address these issues, some New England states are increasingly using other mechanisms, including but not limited to long-term contracts. In addition, much of the on-shore wind resource potential is located: (1) in an electrically weak portion of the New England system, such as Northern Maine, and (2) on the other side of transmission interfaces that limit delivery of renewable power to consumers in southern New England. These challenges have resulted in delays in interconnecting new generators in the Maine portion of the system and the inability to use all of the output of current wind generators.

Today, the wholesale competitive market is generally not designed to accommodate state laws that seek to increase reliance on renewable and certain no-carbon resources. Moreover, the resource-neutral competitive wholesale markets have resulted in an increasing reliance on natural gas-fired resources. NESCOE has observed over the last several years that New England's resource-neutral competitive wholesale markets must accommodate state energy and environmental laws in order for those markets to be sustainable over time. NEPOOL commenced a process to consider potential market-based solutions this challenge in the Summer 2016.[36]

[35] *See*, for example, ISO New England's Regional Electricity Outlook, available at https://www.iso-ne.com/about/regional-electricity-outlook/grid-in-transition-opportunities-and-challenges/natural-gas-infrastructure-constraints.

[36] *See* fn. 4, above.

V. The Study Approach

LEI modeled the New England power system based on several hypothetical futures that NESCOE defined using a simulation-based approach of the ISO-NE's energy and capacity markets.

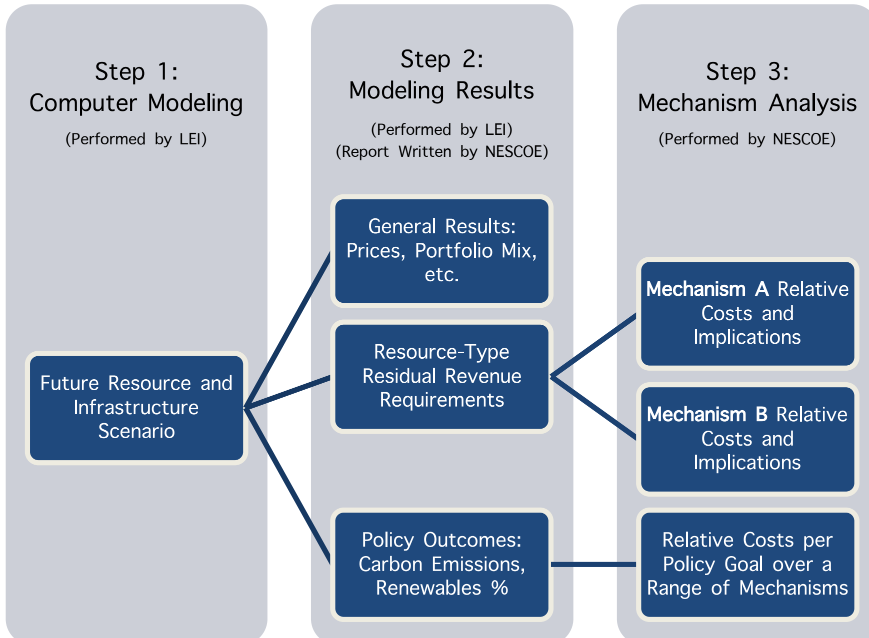
LEI's analysis identified the amount of money existing and new resource types would need to "break even" financially. The analysis is intended to show which resource types might need revenues in excess of what the New England wholesale markets will pay them, according to the LEI model. This study refers to that difference as "missing money."

LEI's model looked at the "missing money" for existing and new resources 1) under the status quo (referred to here as the Base Case), and, 2) under a range of other hypothetical scenarios and infrastructure expansion options (referred to here as Alternative Scenarios). LEI's model also forecasted how often the regional market would select each resource type to supply energy to meet forecasted demand under normal weather conditions based on ISO-NE's load forecast. On the basis of the simulated energy market dynamics of various resources, the model also reported aggregate level of carbon dioxide emissions from the power sector.

With LEI's modeling results in hand, in Phase II, NESCOE will analyze various mechanisms through which states could provide the "missing money" to renewable and clean energy resources, if and to the extent a state requires such resources to comply with state laws. These will include an RPS, a Clean Energy Standard, Long-Term REC Contracts, a Centralized Auction-Based Procurement, and Strategic Transmission Investments. A Phase II report discussing that analysis is expected to be published in 2017.

LEI's modeling discussed in this Phase I of the study also estimated the likelihood of achieving state energy and environmental objectives in the various hypothetical future scenarios. These forecasts will allow NESCOE to compare the *relative* costs of the mechanisms, resource options, and infrastructure choices.

Figure 1: Overview of Study Approach



A. Assessing the Going-Forward Ability of New and Existing Resources in New England to Provide Service – A Look at Profitability or Losses

LEI forecasted future New England wholesale electricity market prices for the energy and capacity markets.[37] These market price forecasts enabled LEI's model to estimate the market-based revenues that resources would earn in those markets.[38]

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37 This study does not examine the Ancillary Services markets, which currently provide less than 5% of regional market revenues. It is generally understood that Ancillary Services markets will grow and require adjustments if the region adds considerably more intermittent resources, such as wind. As the amount of intermittent resources on the system grows, the missing money for existing and new combined cycle natural gas-fired resources is expected to decline.

38 *See also* Section VI.A. at 26-31 for a fuller discussion of how energy and capacity markets work together.

Table A: Wholesale Electricity Market Products and Services

Wholesale Market:	Product:	Note:
Energy	Production of, or the ability to instantaneously produce, energy	The largest market, currently providing ~ 85% of revenue[39]
Forward Capacity	Obligation to participate in the energy market every day	Second largest market, provides the critical remaining revenue (profit) ~ 10% of revenue
Ancillary Services[40]	Grid operating support, including energy reserves, voltage, and frequency, and system restart capability	Collectively, a small but essential market segment[41]

LEI also estimated what it would cost new and existing resources to produce power over the study period.[42] These are a resource's expenses. Of course, resources earn profits when revenues exceed expenses and, conversely, resources with expenses that exceed revenues incur losses. This study refers to such forecasted losses as "missing money".

When New England has excess capacity, *existing* resources generally set capacity prices. Alternatively, when the region does not have enough resources to meet forecasted peak demands, *new* resources generally set capacity prices.

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39 For more information regarding the relative magnitude of the various wholesale electricity markets from 2008 to 2015, *see* 2015 Report of the Consumer Liaison Group ("2015 CLG Report"), at Table 3 on page 34, available at http://www.iso-ne.com/static-assets/documents/2016/03/2015_report_of_the_consumer_liaison_group_new_template_final.pdf. This general information is provided to explain the relative size of the markets. Individual resource types may earn different proportions of their wholesale market revenues than the percentages in the chart.

40 LEI's modeling does not include ancillary services.

41 ISO New England's 2010 New England Wind Integration Study ("NEWIS") found that increasing penetration of wind resources would require additional ancillary services to maintain reliable system operations. NEWIS identified the need for additional frequency regulation and reserve services. A summary of the NEWIS findings is available at https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2010/nov162010/newis_iso_summary.pdf. The full NEWIS final report is available at https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/reports/2010/newis_report.pdf.

42 LEI's analysis of going forward costs included different components for new and existing resources. For new resources, going forward costs included return on equity. For existing resources, going forward costs did not include return on equity or significant capital expenditures. This distinction is based on the economic theory that existing resource owners would not include so-called "avoidable" costs in their capacity market supply offers. For more information about the study's assumptions and market models, see the Base Case Results in Appendix B, at 20, 27-28, and 35, also available at http://nescoe.com/wp-content/uploads/2016/11/Mechanisms_BaseCase_November2016.pdf.

Figure 2: Relationship Between Market-Based Revenues and Resource Profitability

In sum, LEI (1) provided "missing money" estimates for new and existing resource types in New England and (2) estimated how much energy and emissions these resources would produce under future hypothetical electricity market conditions.

B. Assessing Possible Scenarios: The Status Quo vs. Other Hypothetical Scenarios

The Base Case represents the status quo. The alternative scenarios represent different hypothetical futures - with different resources and infrastructure expansions - in two future years, 2025 and 2030. The *differences* between the Base Case (status quo) and the alternative hypothetical futures scenarios tell the story about the effects of various resource and infrastructure expansion possibilities.

Figure 3 below illustrates the purpose for each of the alternative future scenarios. The top half of the graphic presents the resource and infrastructure scenarios: Expanded RPS, additional Clean Energy Imports, and the Combined Renewable and Clean Energy Scenario. The alternative hypothetical future representing an expansion to the RPS is found in two scenarios: (1) the Expanded RPS 35%-40% Scenario (adds approximately 4,850-6,500 MW of renewables), and (2) the More Aggressive RPS 40%-45% Scenario (adds approximately 7,250-9,250 MW of renewables). The bottom half of the graphic presents the hypothetical "what if" scenarios: Nuclear Retirements and Expanded RPS Without Transmission. As discussed further below, LEI examined the Nuclear Retirements Scenario under three different levels of assumed natural gas prices.

LEI performed two hypothetical "what if" scenarios to provide additional information about (1) the value of existing clean energy resources (i.e., "what if" the remaining nuclear resources retired?) and (2) the level of congestion that would occur without new transmission for new on-shore wind resources (i.e., "what if" the assumed on-shore wind resources were built without the transmission to deliver the power?).[43]

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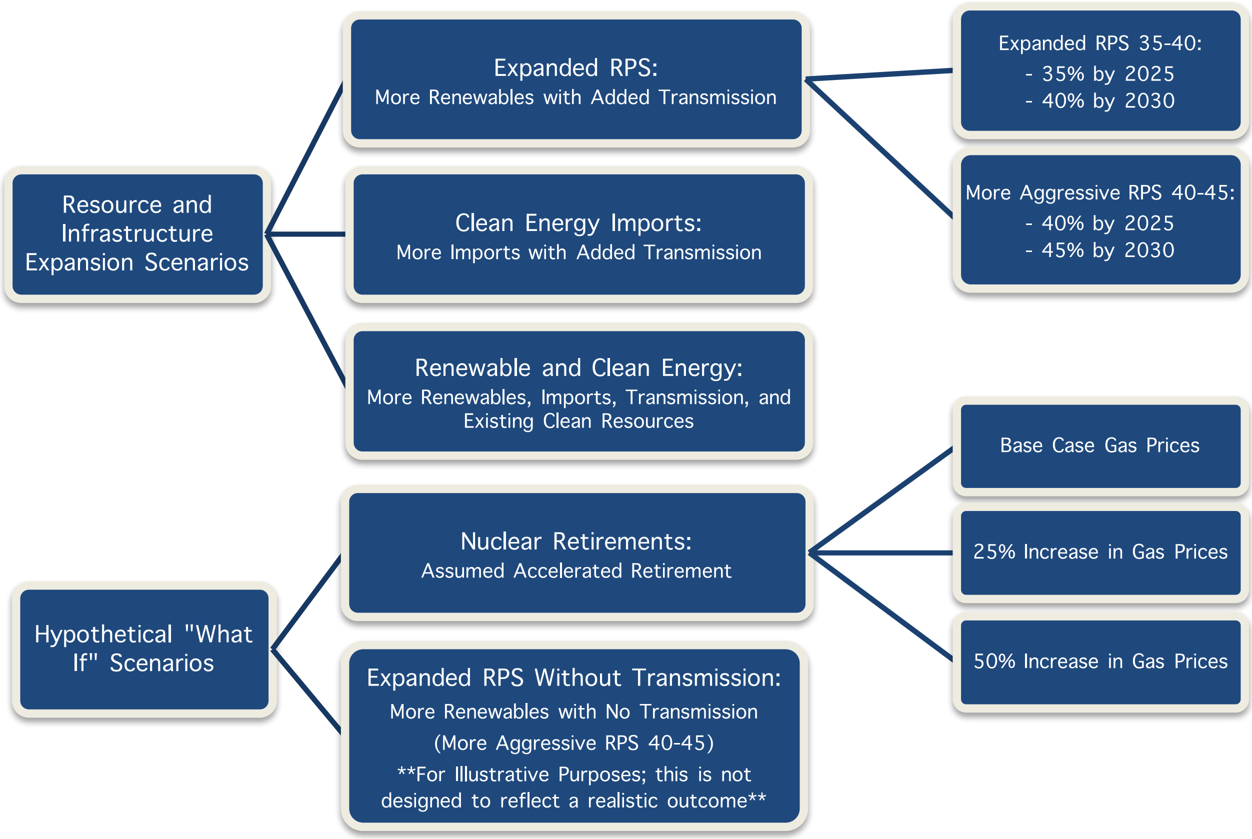
43 Such hypothetical "what if" scenarios are called counterfactuals.

Figure 3: Alternative Hypothetical Future Scenarios



As described further below, the system modeling for two of the Expanded RPS Scenarios assumed that transmission for new on-shore wind resources would be built. The study presents the results of the Expanded RPS Scenarios in two ways: with and without costs for such transmission. When transmission costs are included in the results, they are added to new on-shore wind resources' "missing money" estimates (i.e., those resources have more missing to account for the transmission cost). In addition, one of the Expanded RPS Scenarios examined the implications of not building the transmission necessary to deliver new on-shore wind power to customers in New England. This last scenario - assuming more renewables without transmission to move it to customers - is not necessarily a plausible outcome, but is presented to provide information regarding the level of transmission constraints and resource curtailment. The scenarios do *not* suggest that adding new on-shore wind resources that require new transmission is the only way to increase the level of renewable and clean energy resources in the region. As shown in the expanded RPS scenarios, additional solar photovoltaic and off-shore wind resources, among others, could be used to expand renewable energy penetration in New England.

1. Scenario No. 1: The Base Case (i.e., the Status Quo)

The Base Case represents the status quo: current laws, policies, market rules (including the MOPR), and infrastructure. The future demand for electricity is ISO-NE's 50/50 load forecast, net of energy efficiency and behind-the-meter solar photovoltaics.

- The transmission system is the *existing* infrastructure *plus already approved reliability-based upgrades* that are *currently* in the process of development over the planning horizon.
- The region's domestic generation fleet includes all of the *existing units* in the ISO-NE control area and those recently cleared in the most recent Forward Capacity Market ("FCM") auctions. Retirements are based on recent FCM results and, going forward, when a resource does not meet its minimum going forward fixed costs for three consecutive years.[44] Renewable resources are added commensurate with the region's *existing* Renewable Portfolio Standard goals.
- Imports from neighboring regions are assumed to maintain recent seasonal and daily patterns.[45]
- To the extent that the assumed renewable resource additions are insufficient to cover the region's Installed Capacity Requirement, a supply of generic new combined-cycle natural gas-fired units are available for the model to select.
- The fuel price forecasts are based on empirical analyses of recent seasonal trends and current exchange-traded commodities forward prices. The natural gas infrastructure is the *existing* network plus additions with capacity *subscriptions in advanced permitting stages* and, based on the consultant's recent analysis, are reflected in *current* market prices.
- The emissions costs are based on *exchange-traded forward prices* in the short term and escalated at a rate of inflation over the long-term.[46]

In addition to the Base Case, the study examined six alternative hypothetical future scenarios.

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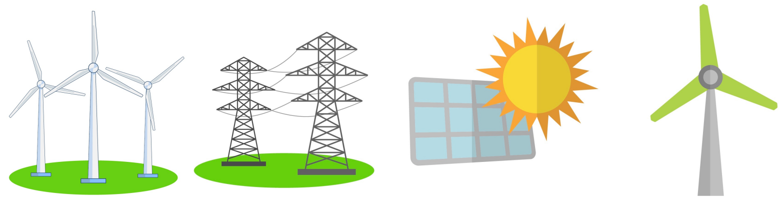
44 LEI did not apply the retirement logic to natural gas combustion turbines that cleared FCA #10.

45 For more information about the study's assumptions regarding interface flows, see the Base Case Results in Appendix B, at 38-39, also available at http://nescoe.com/wp-content/uploads/2016/11/Mechanisms_BaseCase_November2016.pdf.

46 For more detail regarding assumed carbon dioxide emission allowance prices, see *id.* at 37.

2. Scenario No. 2: Expanded RPS



Expanded RPS Case: 35% in 2025 and 40% in 2030 ("Expanded")

More Aggressive RPS Case: 40% by 2025 and 45% by 2030 ("Aggressive")

The study assumed the current RPS requirements as provided in state laws were increased in the years 2025 and 2030. The study looked at hypothetical increases in the RPS requirements at two different levels: (1) An Expanded RPS Case of 35% by 2025 and 40% by 2030, and (2) A More Aggressive RPS Case of 40% by 2025 and 45% by 2030.

In addition, the model assumed that New England expanded its transmission system to enable delivery of greater levels of on-shore wind power to customers across the region, with the funding of costs for such transmission presented in two different ways: (a) paid through some means outside of the market (such as, for example, through one or more states voluntarily agreeing that customers would fund required transmission),[47] and (b) paid for by the new on-shore wind resource as part of its interconnection costs and therefore included in the "missing money" estimates. At a high level, the cost of transmission for the Expanded RPS Scenario is about $3.8 billion ($42-$49/MWh) and for the Aggressive Scenario, about $5.65 billion ($43-$54/MWh).[48] The study also examines the impact of *not* building the transmission to deliver new on-shore wind resources in another scenario, as described further below.

a) Expanded RPS 35%-40% Scenario ("Expanded")

In the first alternative hypothetical future scenario, the study assumes an expansion of the aggregated state RPS requirements from 26.28% to 35% by 2025 and 28.71% to 40% by 2030. To enable the production of renewable energy sufficient to meet these levels, the study assumes

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47 An example of such a funding mechanism is participant-funded Elective Transmission Upgrades.

48 The More Aggressive RPS 40%-45%'s hypothetical 3,600 MW high-voltage direct current ("HVDC") transmission configuration to deliver new on-shore wind resources is estimated to cost, at a high level, approximately $5.65billion. On an annual basis, this would equal approximately $904 million. Apportioning the costs of the transmission to the new on-shore wind resources in the More Aggressive More Aggressive RPS 40%-45% Scenario adds approximately $43-$54/MWh to the "missing money" for this resource type. See Appendix A for more information and an explanation of how this cost was estimated. Similarly, the Expanded RPS 35%-40%'s hypothetical 2,400 MW HVDC transmission configuration to deliver new on-shore wind resources is estimated to cost, at a high level, approximately $3.8 billion. On an annual basis, this would equal approximately $608 million. Apportioning the costs of the transmission to the new on-shore wind resources in the Expanded RPS 35%-40% Scenario adds approximately $42-$49/MWh to the "missing money" for this resource type.

the region develops new on-shore wind resources, new solar photovoltaic ("PV") resources, and new off-shore wind resources. The power system model assumes sufficient transmission upgrades to allow interconnection and delivery of the new on-shore wind resources. Specifically, the study assumes that the region develops the following renewable resources *in addition* to the resources assumed in the Base Case.

Table B: RPS 35%-40% Scenario – Capacity Additions (Nameplate MW)

Renewable Resource Type	2025	2030
On-Shore Wind and Transmission	2,750	3,575
Solar PV	600	1,000
Off-Shore Wind	1,500	2,000

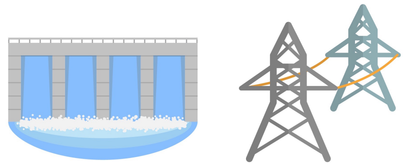
b) More Aggressive RPS 40%-45% Scenario ("Aggressive")

In the second alternative hypothetical future scenario, the study assumes an expansion of the states' aggregated RPS requirements to 40% by 2025 and 45% by 2030. To enable the production of renewable energy sufficient to meet such hypothetical levels, the study assumes the region develops new on-shore wind resources with associated transmission as described above, new solar photovoltaic (PV) resources, and new off-shore wind resources. Specifically, the study assumes that the following renewable resources are developed *in addition* to the resources assumed in the Base Case.

Table C: More Aggressive RPS 40%-45% Scenario – Capacity Additions (Nameplate MW)

Renewable Resource Type	2025	2030
On-Shore Wind and Transmission	4,250	5,500
Solar PV	1,000	1,250
Off-Shore Wind	2,000	2,500

3. Scenario No. 3: Clean Energy Imports Scenario ("Imports")



7,800 GWh Clean Energy Imports over 1,000 MW HVDC (at a 90% capacity factor)

The Imports Scenario assumes:

1) New England expands the number of transmission interconnections with neighboring systems by 1,000 MW,

2) New England increases the level of clean energy imports into the region by approximately 7,800 GWh (at a 90% capacity factor) over that new transmission, and

3) that the new interconnection is connected to the New England transmission system at a point that will enable delivery of additional clean energy imports to customers across the entire system.[49]

In this scenario, the study assumes that the supplier of clean energy imports into the region (i) pays for the new transmission and that (ii) the supplier recovers the costs of the transmission (approximately $1.7 billion or approximately $34/MWh) through energy and capacity market revenues.[50] Since the actual costs of providing the clean energy imports are not known or estimated in the study, the energy supply costs for the clean energy imports are not included in the missing money calculation. The study assumes that the energy and capacity revenues provide enough money for a clean energy imports supplier to pay for the transmission and deliver the power. The study does not examine whether the remaining profit is enough to cover the energy supply cost component (the amount for producing the power) for clean energy imports.[51]

The "missing money" estimate for all resources is equal to energy and capacity revenues minus going forward fixed costs. For this resource, going forward fixed costs include two components: (1) energy supply and (2) transmission costs. As described above, actual energy supply costs are not known and are excluded. The remaining going forward fixed cost is therefore only the transmission cost component (approximately $34/MWh). Accordingly, the "missing money" estimate for this Clean Energy Imports resource is equal to energy and capacity market revenues

[49] More specifically, this location within the model is known as the central Massachusetts hub.

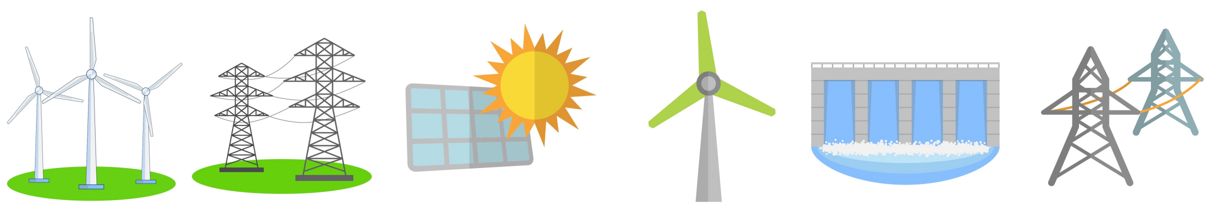
[50] The study's hypothetical 1,000 MW HVDC transmission configuration to deliver clean energy imports is estimated to cost, at a high level, approximately $1.7 billion. On an annual basis, this would equal approximately $265 million. Charging the costs of the transmission to the clean energy imports in the Clean Energy Imports Scenario results in approximately $34/MWh in costs for this resource type.

[51] Similarly, the study does not examine opportunity cost of selling the power to another regional market besides New England.

minus assumed transmission costs. Again, one would have to apply judgment to estimate the actual energy supply costs necessary to provide this imported power.

For additional clarity, the Clean Energy Imports *scenario* includes the addition of a new clean energy imports *resource*. The energy and capacity price and power sector emissions results presented in section VI. Study Results are at the scenario level. Since the actual costs of supplying the clean energy imports are not known or estimated in the study, the clean energy imports resource type is not included in the missing money results.

4. Scenario No. 4: Combined More Aggressive Renewable and Clean Energy ("Combined")



Combined: More Aggressive RPS Case of 40% by 2025 and 45% by 2030 *Plus* 7,800 GWh Clean Energy Imports over 1,000 MW HVDC (at a 90% capacity factor)

The Combined Scenario looks at the consequences of combining the Aggressive - Scenario 2 and Scenario 3 - Imports scenarios, described above. Specifically, this scenario examines the impacts of the total amount of 1) additional renewable resources along with associated new transmission that would enable renewable power to serve the region, and 2) clean energy imports and associated new transmission on market dynamics and the "missing money" for existing and new resources in New England.

The study treats the cost of transmission in this Combined Scenario the same as in the individual scenarios. That is, transmission for new on-shore wind resources ($43-$54/MWh) is assumed to be (a) paid for through some means outside of the market (such as, for example, through one or more states voluntarily agreeing that customers would fund transmission), or (b) paid for by the new on-shore wind generator as part of its interconnection and included in the "missing money" estimates. The study assumes the supplier of clean energy imports pays for the transmission for incremental clean energy imports ($34/MWh) and recovers the costs through energy and capacity market revenues.

Table D: Combined More Aggressive Renewable and Clean Energy Scenario Capacity Additions (Nameplate MW)

Renewable and Clean Resource Type	2025	2030
On-Shore Wind and Transmission	4,250	5,500
Solar PV	1,000	1,250
Off-Shore Wind	2,000	2,500
Clean Energy Imports	1,000	1,000

5. Scenario No. 5: Nuclear Retirements ("No Nuclear")

Retire Remaining Nuclear Resources (3,209 MW) and
Replace with Natural Gas-Fired (Dual Fuel) Resources (3,000 to 3,500 MW)

The No Nuclear Scenario assumes New England's remaining existing nuclear units retire on an accelerated schedule. This scenario examines the consequences of such retirements on market dynamics and the "missing money" estimates for existing and new resources in New England.

The No Nuclear Scenario assumes that nuclear resources in New England retire by 2025 and that base-load natural gas-fired resources replace them to maintain reliability. Under that assumption, the replacement plants create an increased demand for natural gas. This added demand for natural gas could increase natural gas prices significantly (assuming that the natural gas infrastructure and supply outlook do not change over time). Accordingly, this scenario looks at two different assumed natural gas prices, specifically prices that are (1) 25% higher and (2) 50% higher than the gas prices assumed in the other scenarios. The study models the results using the two levels since the actual natural gas price increase is unknown. The study did not address the reliability concerns that would arise from the constraints on the natural gas infrastructure.

6. Scenario No. 6: Expanded RPS Without Transmission ("No Transmission")

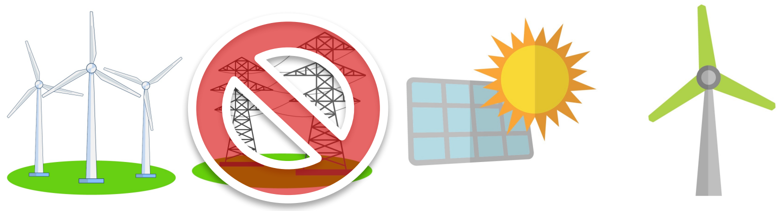


Table E: Expanded RPS Without Transmission Scenario Capacity Additions (Nameplate MW)

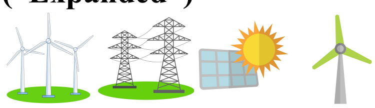
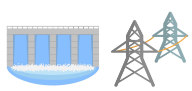
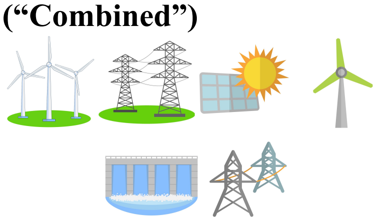
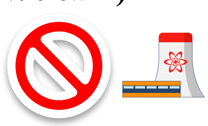
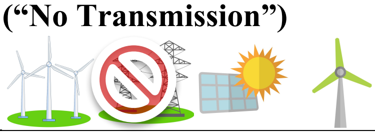
Renewable Resource Type	2025	2030
On-Shore Wind ~~**and Transmission**~~	4,250	5,500
Solar PV	1,000	1,250
Off-Shore Wind	2,000	2,500

The No Transmission Scenario looks at the consequences of expanding the current RPS requirements to higher percentage levels in 2025 and 2030 without adding the necessary transmission for new on-shore wind resources. This scenario does not suggest that new on-shore wind that requires transmission is the only way to satisfy expanded RPS requirements. This scenario assumes an expansion of the states' aggregated RPS requirements to 40% by 2025 and 45% by 2030. This scenario is not intended to project that the region would fund an increase in on-shore wind without corresponding transmission. Rather, the No Transmission Scenario helps to illustrate 1) the level of congestion associated with increasing the region's new on-shore wind resource without expanding the transmission system and 2) how congestion impacts the profitability of existing and new on-shore wind resources located in Maine.

C. Summary of Scenarios

To summarize, the chart below provides an overview of the study scenarios. The assumed details of the hypothetical resource and infrastructure additions are presented next to each scenario. Importantly, the study assumes that the region develops the following renewable resources *in addition* to the resources assumed in the Base Case, including energy efficiency and behind the meter solar photovoltaics.

Table F: Overview of Scenario Assumption Details

Scenario	2025	2030
1: Expanded RPS 35%-40% ("Expanded") 	+ 2,750 MW On-Shore Wind (+2,400 MW HVDC) + 600 MW Solar PV +1,500 MW Off-Shore Wind	+3,575 MW On-Shore Wind (+2,400 MW HVDC) +1,000 MW Solar PV +2,000 MW Off-Shore Wind
2: More Aggressive RPS 40%-45% ("Aggressive") 	+4,250 MW On-Shore Wind (+3,600 MW HVDC) +1,000 MW Solar PV +2,000 MW Off-Shore Wind	+5,500 MW On-Shore Wind (+3,600 MW HVDC) +1,250 MW Solar PV +2,500 MW Off-Shore Wind
3: Clean Energy Imports ("Imports") 	+7,800 GWh Clean Energy (+1,000 MW HVDC) (90% Capacity Factor)	+7,800 GWh Clean Energy (+1,000 MW HVDC) (90% Capacity Factor)
4: Combined Renewable and Clean Energy ("Combined") 	+4,250 MW On-Shore Wind (+3,600 MW HVDC) +1,000 MW Solar PV +2,000 MW Off-Shore Wind +7,800 GWh Clean Energy (+1,000 MW HVDC)	+5,500 MW On-Shore Wind (+3,600 MW HVDC) +1,250 MW Solar PV +2,500 MW Off-Shore Wind +7,800 GWh Clean Energy (+1,000 MW HVDC)
5: Nuclear Retirements ("No Nuclear") 	Retire remaining nuclear resources by 2025; Nuclear resources replaced by gas-fired resources	Retire remaining nuclear resources by 2025; Nuclear resources replaced by gas-fired resources
6: Expanded RPS Without Transmission ("No Transmission") 	+4,250 MW On-Shore Wind ~~(+3,600 MW HVDC)~~ +1,000 MW Solar PV +2,000 MW Off-Shore Wind	+5,500 MW On-Shore Wind ~~(+3,600 MW HVDC)~~ +1,250 MW Solar PV +2,500 MW Off-Shore Wind

D. Compare Scenarios' Emissions Level and Resource Mix Outcomes

For each scenario, the study looked at assumed power sector emission and resource mix outcomes under the range of "what if" futures. The study estimated the ability of certain assumptions to achieve hypothetical carbon emission reduction targets and RPS percentages.

Limitations of Modeling Results

LEI modeling results are based on **assumptions** that NESCOE identified, not facts. History may prove any or all of them wrong, to varying degrees. The assumptions significantly influence which resources LEI's model selects to supply electric energy, when and for how long, and the prices at which resources produce energy and supply capacity. The assumptions also include what new resources cost.

LEI's **energy market model** assumes generators are available consistent with annual averages, that the weather is always normal, and that the load forecast is always accurate. It does not include operational contingencies or extreme stresses on the natural gas system. The model does not look at the costs of additional ancillary services to integrate significant amount of renewable energy, and does not account for losses.

LEI's model retires resources (after three years of losses with the exception of the new natural gas combustion turbines that cleared FCA # 10) and identifies new resources coming into the market based on a **computer-generated simulation of future ISO-NE Forward Capacity Auctions** using, with some exceptions (e.g., the MOPR), existing market rules. On the basis of economic theory, the capacity market model does not include all costs, such as return on equity, in *existing* resources' capacity market offers. Nevertheless, such costs may influence resource owners' business decisions.

LEI's model assumes market participants have a similar financial **risk tolerance** in assessing retirement decisions of existing generation. In reality, resource owners have different levels of risk tolerance.

LEI's model does not explicitly limit **power sector air emissions** for modeling of these hypothetical scenarios. LEI used a price on carbon dioxide emissions based on current RGGI allowance secondary market prices, escalated at an assumed rate of inflation that essentially keeps carbon prices flat in real dollar terms. The model's price on carbon dioxide emissions, on its own, does not limit the amount of power sector air emissions.

LEI's renewables development outlook and perspective on transmission system limitations directly influence the supply of RECs in several scenarios. LEI assumes New England may be under-supplied with RECs due to transmission system limitations and other factors. If assumptions about imports of RPS-qualified renewable energy or levels of renewable output from local resources prove to be understated, the level of available RECs may be closer to New England RPS targets.

VI. Study Results

This section summarizes the study results. For each scenario described above, this section provides price information, resource mix details, and carbon dioxide emissions.

A. Energy and Capacity Market Outlook Across the Scenarios

The New England energy and capacity markets are interrelated: each is designed to operate with the other. Together, their purpose is to maintain an adequate supply of resources in the region and to serve electricity demand reliably at the lowest cost over the long-term. An increase (or decrease) in the prices in the energy market will, over time, result in a decrease (or increase) in the prices of the capacity market. The combined revenue from both the energy and capacity markets determines resources' profitability. Different resource types get more or less revenues from one market or the other.

1. Additions of Renewable and Clean Energy Resources Reduce Energy Market Price Levels

In New England, energy market prices are closely related to the price of natural gas, the dominant fuel source in the region. Forecasted energy market prices gradually increased in 2025 and 2030, in all cases, as natural gas prices increase. In all scenarios, however, forecasted energy market prices were generally within the range of historical energy market prices.

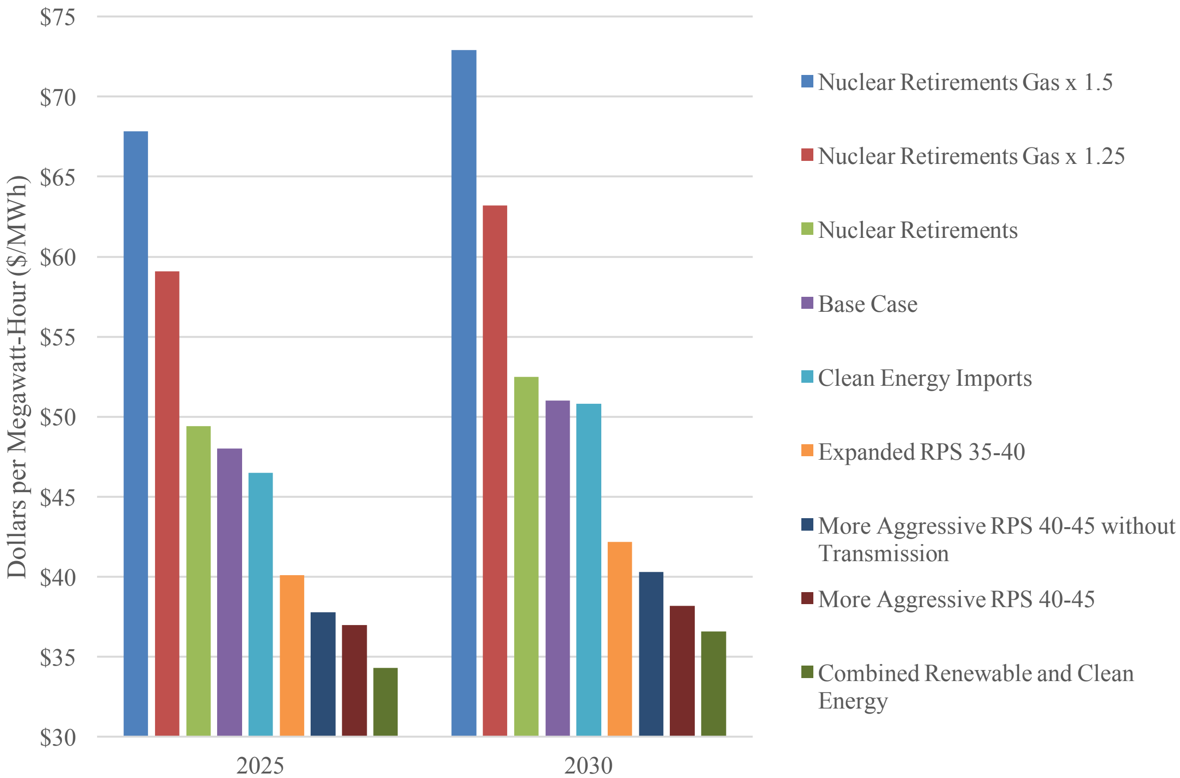
- In the Base Case, energy prices were in the middle of the range of the other scenarios' forecasted prices.
- In the No Nuclear Scenario, where many megawatts retire, energy prices were *higher* than the Base Case.[52]
- Energy prices in all other scenarios - all of which add new renewable and clean energy resources - were *lower* than the Base Case.

The chart below presents average annual electricity prices in 2025 and 2030.[53]

[52] LEI also performed two assumed natural gas price sensitivities on the Nuclear Retirements Scenario, discussed below. LEI conducted these additional cases to reflect the potential increase in demand for natural gas associated with the replacing the assumed nuclear retirements with natural gas-fired resources.

[53] The energy and capacity price and power sector emissions results presented in section VI. Study Results are at the scenario level. While the Clean Energy Imports *scenario* includes the addition of a new clean energy imports *resource*, the actual costs of supplying the clean energy imports are not known or estimated in the study. Accordingly, these costs are not included in the missing money results.

Figure 4: Average Annual Energy Market Prices Across All Scenarios[54]



Whether forecasted energy prices are highest or lowest depends on the extent to which New England relies on natural gas-fired resources. As noted, the No Nuclear Scenario had the highest energy prices. In that case, natural gas-fired resources replace retired nuclear capacity and natural gas-fired resources have higher operational and fuel costs. As a result, the nuclear resource retirements lead to higher average annual energy prices, especially during off-peak hours.[55] In the No Nuclear Scenario, energy market prices increased further as assumed natural gas prices increased.[56] Specifically, when natural gas prices are assumed to be 25% higher, energy market prices increased by 20% in the No Nuclear Scenario. When natural gas prices were assumed to be 50% higher, energy market prices increased by 38%. This shows a relationship between assumed natural gas prices and energy market prices that is less than 1 to 1.[57]

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54 All results are expressed in nominal future dollars.

55 Nuclear resources generally operate at maximum output levels for months at a time, even at night. During the nighttime, when electricity demand is lower, nuclear resources have historically supplied a significant portion of the region's energy. The scenario's assumed retirement of remaining nuclear resources affects energy market prices especially at night because of the significant nighttime contribution of nuclear resources being replaced by natural gas-fired resources.

56 The capacity market results for the Nuclear Retirements Scenario were held constant across all three modeling cases.

57 Lowering natural gas prices will also lower electric energy market prices, but not by as much.

In contrast, the Combined Scenario had the lowest energy prices. This is because new renewables and clean energy imports have very low operational and fuel costs and displace natural gas-fired energy production.

Energy prices in scenarios that added renewable and clean energy resources were lower than in the Base Case. Both the Expanded and Aggressive Scenarios assumed additional on-shore wind, off-shore wind, and solar PV resources and expanded the transmission system to enable delivery of new on-shore wind energy.[58] However, recall that the No Transmission Scenario did not expand the transmission system to accommodate delivery of additional on-shore wind resources. This resulted in transmission congestion, which would require ISO-NE system operators to curtail, or hold back, wind resources. Accordingly, energy prices are ***higher*** in scenarios with new on-shore wind without transmission and ***lower*** in scenarios where new on-shore wind has adequate transmission to move the power to customers.

Additional clean energy imports also result in slightly lower energy prices than the Base Case. In the Imports Scenario, the additional transmission interconnection enabled delivery of significant amounts of clean energy into New England. The Imports Scenario's addition of imported clean energy, rather than natural gas-fired resources, enabled the energy market to select lower cost imports, all other factors being equal. As discussed, the Combined Scenario had the lowest energy prices. This reflected the additional clean energy imports and renewable energy to the region's resource mix.

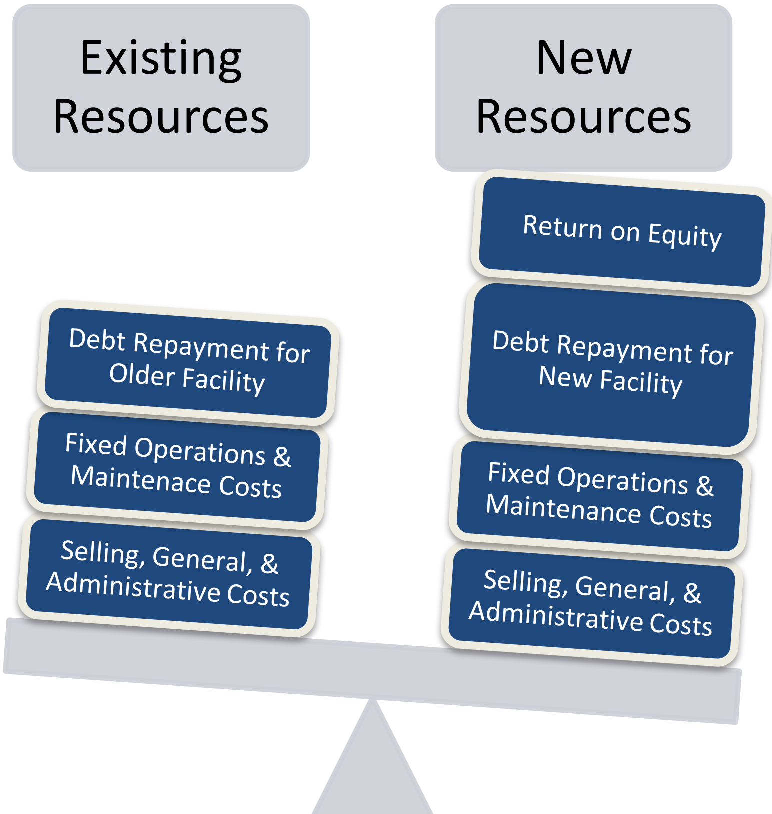
2. Capacity Prices Temporarily Decline in Proportion to Renewable and Clean Energy Resource Additions but Rebound Over Time

The quantity of resources in the region generally determines capacity prices.[59] When New England has excess capacity, *existing* resources generally set capacity prices. When the region does not have enough resources to meet forecasted peak demands, *new* resources generally set capacity prices. New resources generally have higher prices than existing resources because they need to account for expenditures related to building a new facility. Existing resources, on the other hand, only need to recover their operating costs.

[58] The More Aggressive RPS 40%-45%'s hypothetical 3,600 MW HVDC transmission configuration to deliver new on-shore wind resources is estimated to cost, at a high level, approximately $5.65 billion. On an annual basis, this would equal approximately $904 million. Charging the costs of the transmission to the new on-shore wind resources in the More Aggressive RPS 40%-45% Scenario adds approximately $43-$54/MWh to the "missing money" for this resource type. See Appendix A for more information. Similarly, the Expanded RPS 35%-40%'s hypothetical 2,400 MW HVDC transmission configuration to deliver new on-shore wind resources is estimated to cost, at a high level, approximately $3.8 billion. On an annual basis, this would equal approximately $608 million. Charging the costs of the transmission to the new on-shore wind resources in the Expanded RPS 35%-40% Scenario adds approximately $42-$49/MWh to the "missing money" for this resource type.

[59] As described above, the wholesale electricity market product called "capacity" is the obligation to participate in the energy market every day. The capacity market ensures that the region has an adequate level of resources to maintain reliable operation of the electric system. The capacity market also provides revenues to resources. Capacity market outcomes influence whether many resources remain in operation or retire.

Figure 5: Illustration of Why New Resources Are More Expensive than Existing Resources in the Model



Note: In general, existing resources have much lower debt payments, compared to new resources. LEI also does not include equity returns or significant capital expenditures for existing resources, which further increases the cost difference between new and existing resources.

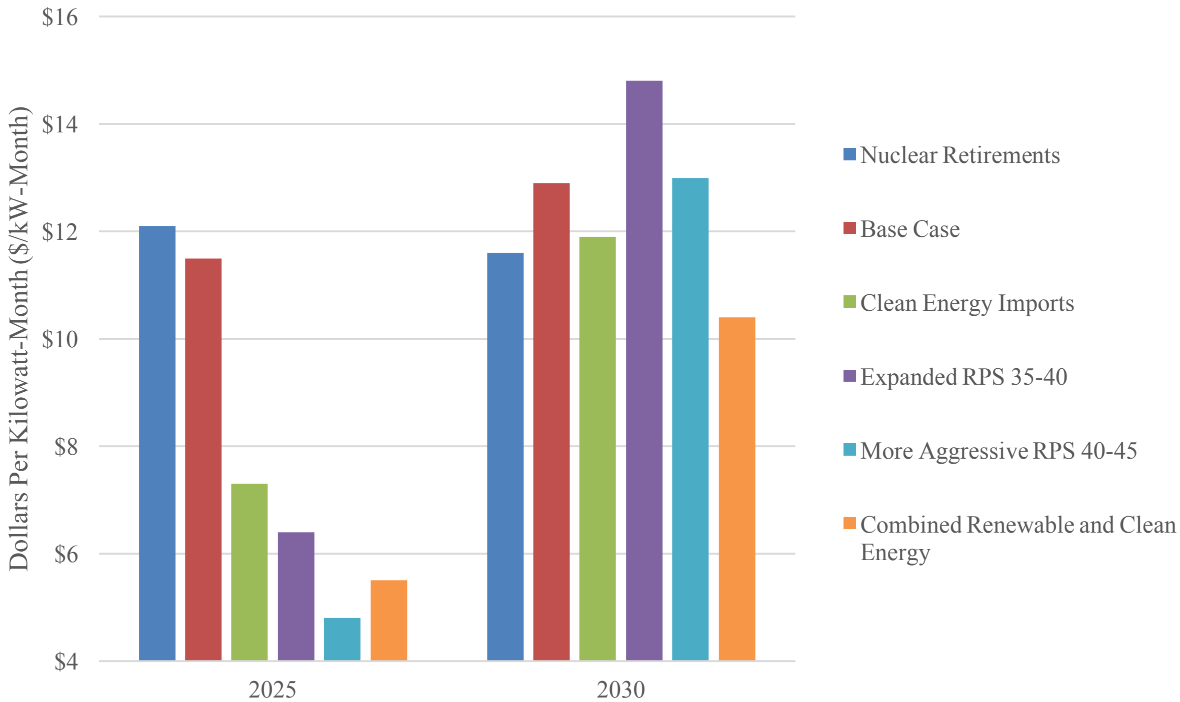
Each scenario added or subtracted varying amounts of renewable and clean energy resources to the region. These assumed amounts influence capacity prices because they create excess supply. Excess supply, in turn, influences the *timing* of when the region would need new resources.[60]

Capacity prices and the cost of building a new natural gas-fired resource eventually come together in the study. This is because: 1) the region's peak demand grows through 2025 and 2030, 2) unprofitable resources retire over time, thereby decreasing supply, and 3) the competitive market selects lower-cost natural gas-fired combined cycle resources to meet that growing demand.

In the study, the addition of new renewable and clean energy resources delays *when* new resources set prices due to the excess supply, and in proportion to the *amount* of new resources (or the amount of excess supply). The chart below shows forecasted capacity prices. As the excess supply is reduced over time, all scenarios trend towards the cost of a new natural gas-fired resource.

60 See Section V. Study Approach, above, for a complete description of the assumed amounts of renewable and clean energy resource additions in each scenario.

Figure 6: Capacity Market Prices Across All Scenarios



All scenarios show surplus capacity in 2020 (the beginning of the study period). This is because of the region's most recent capacity market results, which procured some excess capacity.[61]

By 2025, the Base Case and the No Nuclear Scenario add natural gas-fired resources to maintain reliability, and so new resources set capacity prices. Once New England needs new resources, capacity prices increase and remain near the assumed price of those new resources through 2030.[62]

The Expanded, Aggressive, and Combined Scenarios do not require new resources in 2025.[63] In these scenarios, *existing* resources set capacity prices in 2025. It stays that way until peak

61 Recent capacity market reforms (implementation of downward-sloping demand curve) allow the capacity market to procure more or less than the amount required, depending on price and reliability needs. For more information, see https://www.iso-ne.com/about/key-stats/markets.

62 Once the capacity market reaches supply and demand balance, the so-called "lumpiness" of new entry leads to capacity prices that vary from year to year in a predictable pattern, but remain within a range around the assumed cost of new entry.

63 As noted above, if the study had assumed that the MOPR remained in effect in the hypothetical resource and infrastructure expansion scenarios, new renewable and clean energy resources may not be selected in the capacity market and their contribution to the region's resource adequacy may not be fully realized (i.e., the region would pay twice for the capacity). In that event, additional new combined cycle natural gas-fired resources would be selected by the capacity market in response to higher prices. The study's lack of incorporation of the MOPR results in higher missing money estimates for existing and new resources, compared to a future scenario that continues to apply the MOPR to capacity market participation. The study also did not include potential reliability risks and cost increases associated with additional new combined cycle natural gas-fired resources without additional natural gas capacity being built.

demand grows or until additional retirements signal the need for new resources toward the end of, or just after, 2030 (the end of the study period).

3. Power Sector Air Emissions Decline with the Addition of Renewable and Clean Energy Resources

The chart below shows carbon dioxide emissions from resources located within New England in the various scenarios.[64] The scenarios are arranged from left to right in the order of least to most renewable and clean energy additions. The No Nuclear Scenario has the highest carbon dioxide emissions. This is because natural gas-fired resources replace the retired nuclear units.[65] New England power sector carbon dioxide emissions exceed RGGI targets in the No Nuclear and Base Case Scenarios.[66] The RGGI targets are based on hypothetical emissions limits in the New England states.[67]

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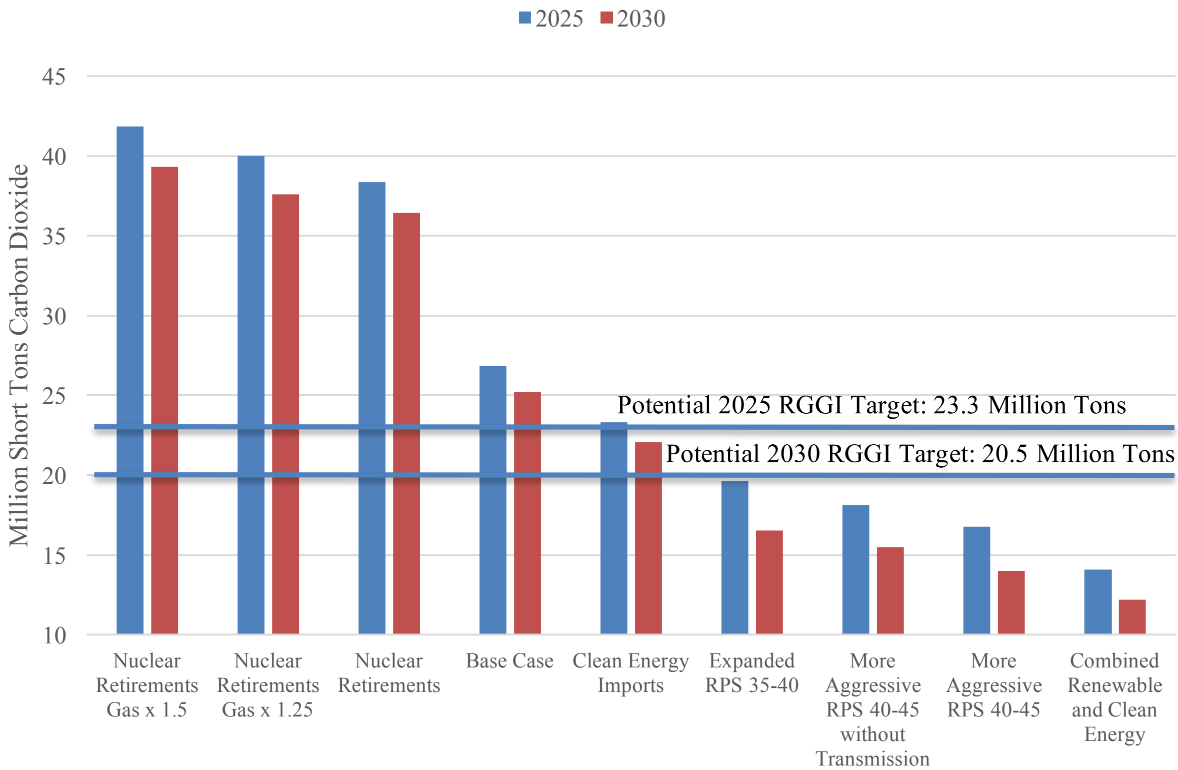
64 Emissions associated with imported power are beyond the scope of the study. Net imports serve approximately 15% of the load in the study. Most of the imports come from a neighboring system with a clean energy resource mix. LEI's power sector emissions modeling results include the carbon dioxide emissions from all resources selected by the market (dispatched) to supply energy (including those <25 MW, which are not subject to RGGI). This does not include actual emissions that may result from resources selected to provide ancillary services like reserves.

65 The Nuclear Retirements Scenario includes two sensitivities with higher gas price assumptions, as discussed below. All else equal, the assumed higher gas prices resulted in higher power sector carbon dioxide emissions due to oil-fired resources being in economic merit in limited circumstances.

66 The RGGI 2016-2017 Program Review process also includes power sector modeling. RGGI's modeling has different objectives, geographic scope, modeling tools, and analytical approach than the modeling that informs this study. While some assumptions are common (e.g., the ISO-NE load forecast), the two analyses are not directly comparable.

67 For more information, *see* http://www.rggi.org/design/2016-program-review.

Figure 7: Power Sector Carbon Dioxide Emissions Across All Scenarios



Importantly, *these results do not mean* that New England would be out of compliance with RGGI. First, the emissions results include a small contribution from resources that are not subject to RGGI.[68] Second, RGGI is the cap-and-trade program that enables emission allowances to be traded among participating states (which also includes Delaware, New York, and Maryland) to achieve reductions at least cost. The results of the No Nuclear and Base Case Scenarios suggest that entities subject to RGGI in New England would likely need to purchase additional allowances or carbon offsets.[69] The chart illustrates a relationship between the amount of renewable and clean energy additions and power sector carbon dioxide emissions. As increasing amounts of renewable and clean energy resources are added, the region's power sector emissions decline.

68 For example, resources < 25 MW are not currently subject to RGGI. Estimating the carbon dioxide emission contributions of these resources is beyond the scope of the study. ISO-NE economic analysis for NEPOOL suggests that an additional 2 to 5 million tons per year may be emitted by the class of resources not subject to RGGI.

69 Note that the higher assumed natural gas prices in the nuclear retirements scenarios results in some oil-fired resources being in economic merit more often. Increased utilization of oil-fired resources in these scenarios results in higher power sector carbon dioxide emissions. In addition, increased purchases of emission allowances would likely result in higher allowance prices and therefore higher energy market prices.

From 2025 to 2030, power sector carbon dioxide emissions decreased in all scenarios. This is due to a combination of assumed load forecast for energy declines and additional renewable and/or clean energy resources.[70]

B. New England's Electricity Market Dynamics are Dominated by Natural Gas-Fired Resources

This section provides examples of the dynamics between the energy market and renewable and clean energy resources. It explains the operation of the energy market and illustrates impacts associated with renewable and clean energy resource additions and subtractions to New England's resource mix. First, this section describes competition among resources in the energy market. Next, it presents the energy market impacts of hypothetical renewable and clean energy resource additions and retirements. Finally, this section discusses how the energy market dynamics impact other markets.

The chart below shows resources that participate in the energy market.[71] Individual resources that participate in this market are represented in the chart by various symbols (described in the chart's legend), sorted from left to right in lowest to highest cost order. The colorful symbols extending from the bottom left to the upper right of the chart represent an increase in the energy offer prices for each resource in the region. This demonstrates, in general terms, that renewable and clean energy resources have lower energy market offer prices than fossil-fueled resources.[72] The chart illustrates the annual average quantity and offer price for resources in New England (the quantity of each resource and its associated offer price can vary from hour to hour and day to day).

This chart also demonstrates how the wholesale electricity market selects resources to serve customers at the least cost.[73] Beginning with the least expensive resources first, ISO-NE's

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70 The load forecast focuses on the level of electricity demand: (1) on an annual basis, and (2) at the time of the peak demand for the year, which is typically the hottest day of the summer in New England. Due to energy efficiency programs and increasing penetration of solar PV, the load forecast for energy (on an annual basis) is declining over time. This has the greatest impact on energy market outcomes, like power sector emissions. In contrast, New England's peak demand during the hottest day of the summer is forecasted to continue to grow. Load forecast for the peak demand of the year has the greatest impact on capacity market outcomes and transmission planning, which are focused on maintaining reliable electric system operations during the time of most stress – the annual peak.

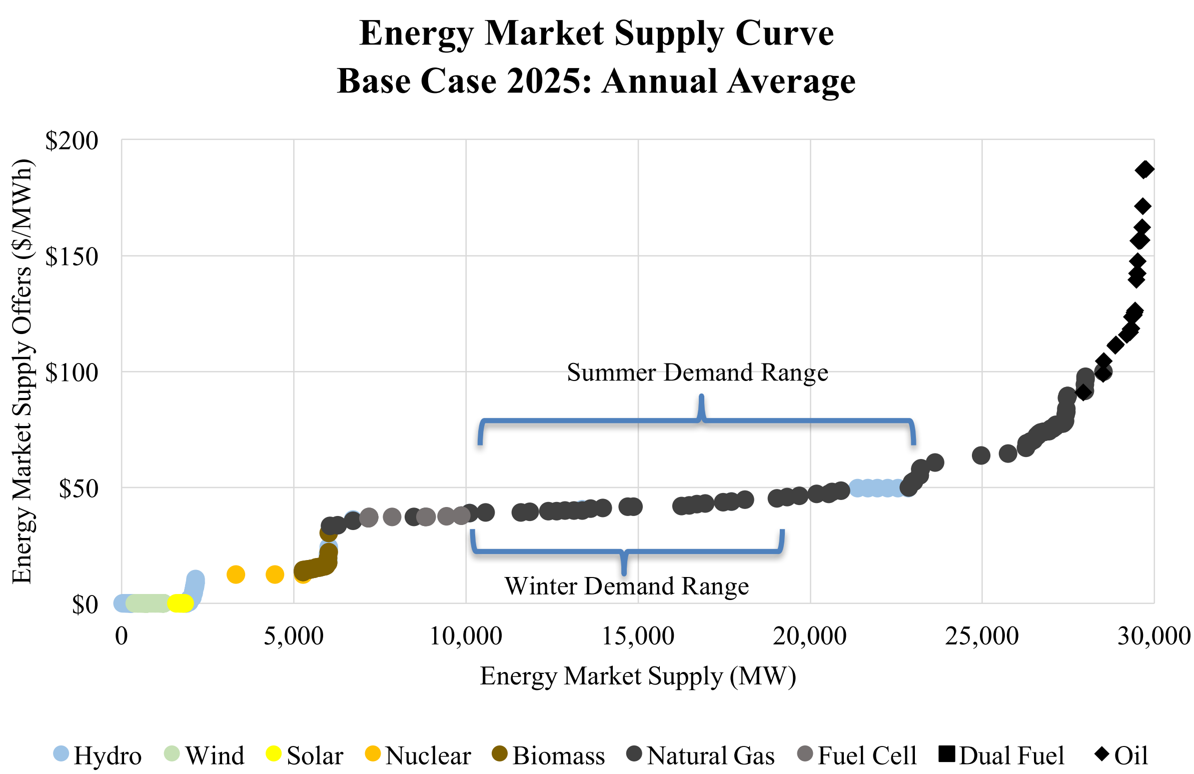
71 The wholesale electricity product traded in the energy market is instantaneous production of electricity. Some resources that offer supply in the energy market also sell capacity. *See* Table 1. By 2025, the economic modeling retired the remaining coal-fired resources in the region.

72 Energy market offer prices are based on the marginal cost of production (the cost attributed to the production of the next megawatt-hour of electricity), primarily fuel and emissions compliance-related expenses. Energy market offers are generally prohibited from including fixed cost components. In contrast, capacity market offer prices are based on the remaining amount of "missing money," including fixed cost recovery. The study analyzed mechanisms focused on resources that still have "missing money" after energy *and* capacity revenues are considered.

73 In New England's energy market, the price paid to *all* resources is the price required by the highest priced resource for that hour. This is often called the "marginal cost," or the price at which a market participant has "offered to supply an additional increment of energy…" ISO New England Inc. Transmission, Markets

energy market administrator selects resources to produce energy up to the instantaneous level of demand. The demand for electricity at the regional level fluctuates over the course of the day and from season to season. The brackets overlaid on the chart illustrate a representative range over which aggregate regional electricity demand fluctuates in the summer and winter seasons.[74]

Figure 8: Energy Market Participants' Supply Offers – Annual Average



The chart also illustrates how natural gas-fired resources set New England energy market prices most of the time. The market selects resources in proportion to the level of regional wholesale demand, shown here in megawatts. The *most expensive* selected resource establishes the price paid to *all* selected resources.[75] The blue brackets illustrate the summer and winter electricity demand ranges. This area of the chart is comprised predominantly by supply offers from natural gas-fired resources. Moreover, the area of the chart to the below (left) and above (right) the normal demand ranges are also mostly natural gas-fired supply offers. For that reason, natural gas-fired resources generally set regional energy prices. When energy demand is low, then the lower cost renewable resources tend to set price.

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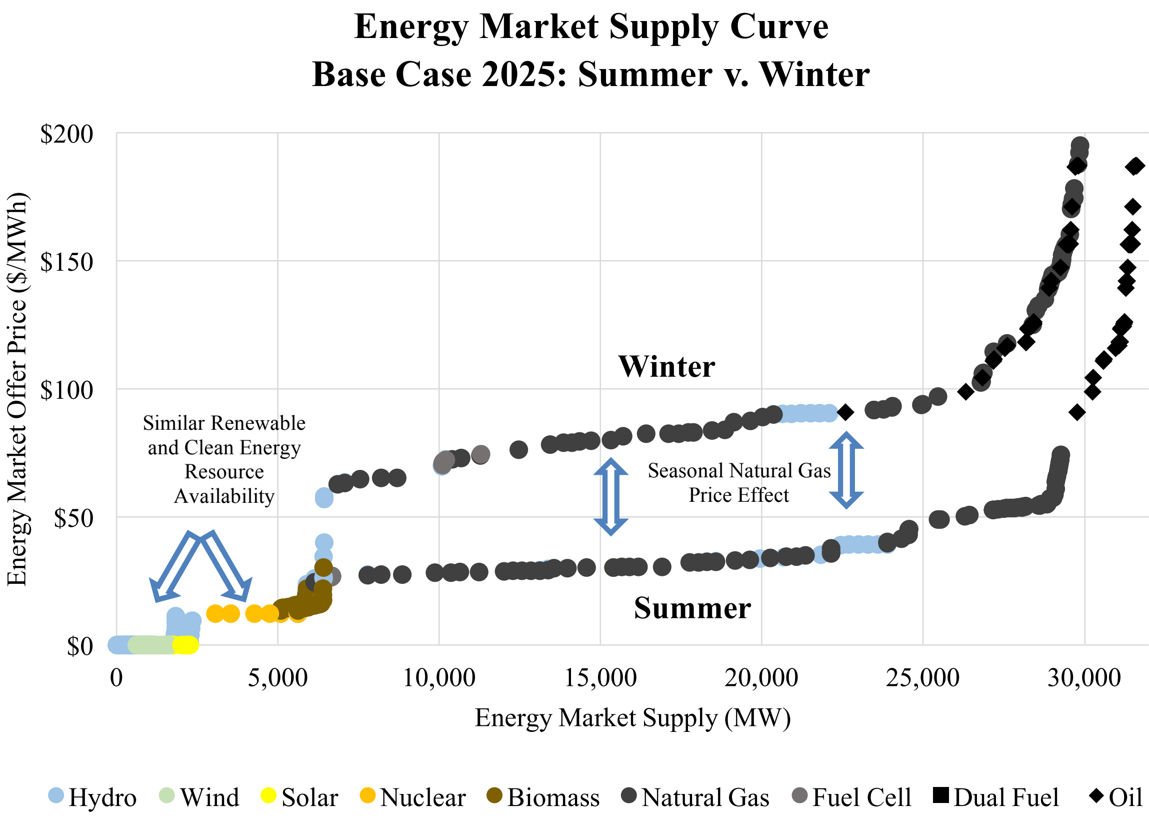
and Services Tariff (the "Tariff") Section III.2.5. Market participants are also able to update their energy market supply offers on an hourly basis. See Tariff Sections III.1.7.7, III.1.10.1A, and III.1.10.9.

74 The summer/winter ranges are based on hourly demand values from August and February 2016, respectively. For more information, *see* https://www.iso-ne.com/about/what-we-do/three-roles/operating-grid.

75 This oversimplifies the market rules. Locational differences and operational considerations also affect an individual resource's energy market revenues.

Figure 9: Energy Market Participants' Supply Offers – Summer and Winter



To provide a sense of the seasonal resource availability and the impact of fuel prices, the chart above shows seasonal variation in the energy market in the Base Case in 2025. The biggest difference between the summer and winter energy market is the assumed natural gas prices.[76] Renewable and clean energy resources appear to have relatively similar prices and availability in summer and winter. Again, the chart illustrates how the energy price in New England is highly dependent on natural gas prices.

The study's resource and infrastructure expansion scenarios show that renewable and clean energy resource additions to the regional resource mix result in reductions in both average annual energy price and power sector carbon emissions. The chart below shows the various scenarios, presented from left to right, in the order of renewable and clean energy resource additions.[77] It illustrates the relationship between the scenarios and the assumed resource mix - a shift to the left or right in proportion to, and in the direction of, the net renewable and clean energy resource

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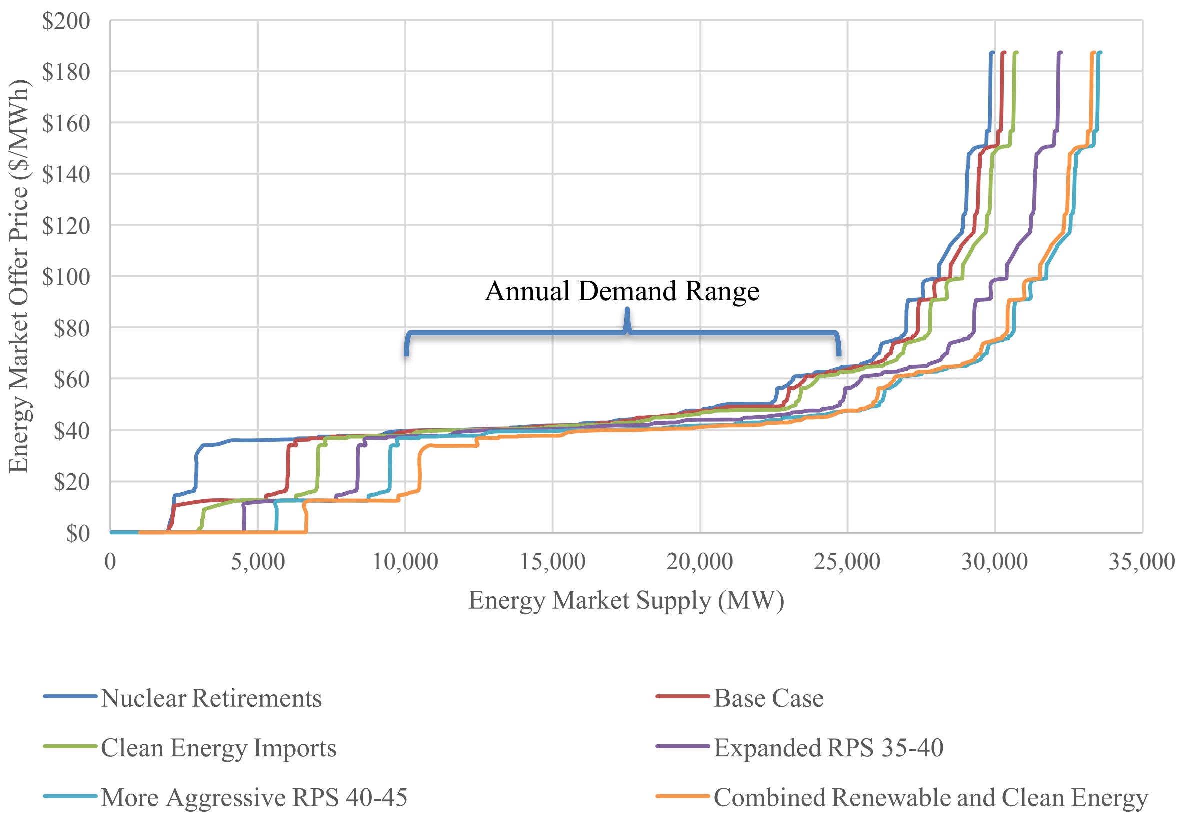
76 This reflects winter season natural gas infrastructure constraints. See Appendix B for fuel price assumptions. For more information regarding New England's natural gas infrastructure, *see* U.S. Energy Information Administration, Today in Energy (December 6, 2016), available at http://www.eia.gov/todayinenergy/detail.php?id=29032.

77 The Expanded RPS 35-40, More Aggressive RPS 40-45, and Renewable and Clean Energy Scenarios all added transmission for new on-shore wind resources. Since energy market offer prices do not include fixed cost components, transmission costs would not have an impact on-shore wind resources' energy market offer prices.

addition. The addition of renewable and clean energy resources shifts all other market participant's supply offers because renewable and clean energy resources have very low operational costs (which determine energy market offer prices). The competitive energy market therefore selects them first. For that reason, emissions go down. Conversely, assumed retirement of clean energy (nuclear) resources enables other higher cost and carbon dioxide emitting resources to be selected to supply energy.

Figure 10: Energy Market Participants' Supply Offers Across All Scenarios

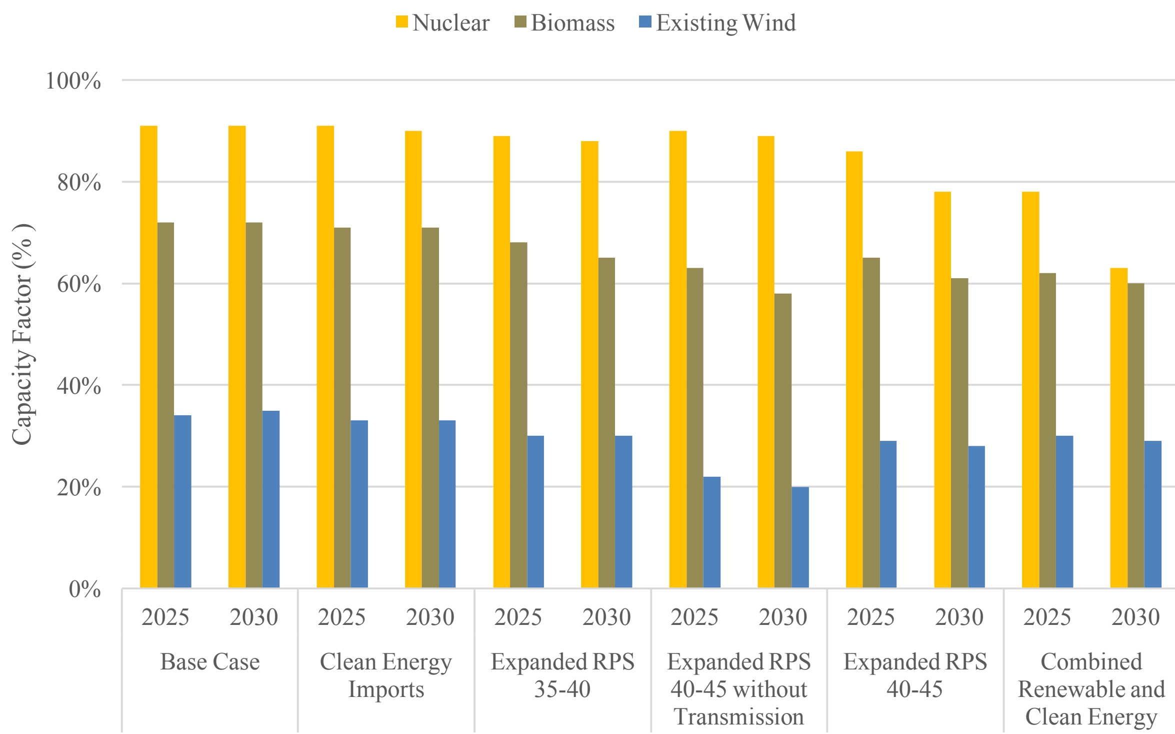


- The No Nuclear Scenario (furthest to the left), which assumed nuclear units retire and are replaced with 3,500 megawatts of natural gas-fired resources, had the *least* amount of new renewable and clean energy.
- The Combined Scenario (furthest to the right) added the *most* renewable and clean energy resources.

Figure 10, above, illustrates how changes to the energy market resource mix reduce carbon emissions. The energy market selects least cost resources and in that process, renewable and clean energy resources displace more expensive resources that happen to emit higher levels of carbon. Over time, such energy market competition results in power sector emissions reductions.

In the scenarios that add the most renewable and clean energy resources, the excess supply of *new* renewable and clean energy resources begin to displace *existing* renewable and clean energy resources. Specifically, if the region adds approximately 25,000,000 MWh (annually) of new renewable resources and/or clean energy imports, existing renewable and clean energy resources produce less power. As shown in Figure 11 below, the LEI model indicates that the resource types that would be affected first are biomass, nuclear, and on-shore wind.[78] The biomass and nuclear resources, while less expensive than natural gas-fired resources, are shown in the model as more expensive than other renewable and clean energy resources. Thus, competition from the new renewable and clean energy resources results in reduced energy production from existing biomass and nuclear resources.[79] Existing on-shore wind production declines primarily from being geographically located in a transmission-constrained portion of the New England system.

Figure 11: Excess Supply Effect on Production (Capacity Factor) for Selected Resources



Existing renewable and clean energy resource production declines from excess supply first arise in the Expanded Scenario, which includes approximately 26,000,000 MWh from new renewable resources. The Aggressive and Combined Scenarios, which add approximately 28,000,000 MWh and 36,000,000 MWh in 2025 respectively, result in an even greater impact on biomass, nuclear, and existing on-shore wind resource production. For example, in the Combined Scenario, nuclear resources' production decreased by 14% in 2025 and by 31% in 2030.[80] As a

78 These resource types also heavily rely on energy market revenues. The production declines would therefore substantially impact revenue estimates for biomass, nuclear, and on-shore wind resources.

79 Technically, all resources that convert fuel into thermal energy to produce electricity are affected. The focus here is on renewable and clean energy resource types that are capable of assisting states with energy and environmental goals.

80 The Combined Renewable and Clean Energy Scenario adds 1,000 MW of clean energy imports, 1,000 MW solar PV, 4,250 MW on-shore wind, and 2,000 MW off-shore wind by 2025 (with an additional 1,250 MW solar PV, 5,500 MW on-shore wind, and 2,500 MW off-shore wind by 2030) to the resources cleared through FCA 10 and assumed Base Case additions. All values are expressed in terms of nameplate capacity. *See* Section IV. Study Approach for more information.

point of comparison, in the Base Case Scenario, nuclear resources' capacity factor was 91%. However, in Combined Scenario, nuclear resources' capacity factor declined to 78% in 2025 and to 63% in 2030.

Energy market competition also impacts the other wholesale electricity markets and the "missing money" for new and existing resource types.

C. All Resources' Profits or Losses Are Affected by Renewable and Clean Energy Resource Additions

This section evaluates the relative profits and losses of different resource types in New England. It compares existing and new resource types across all scenarios, with a focus on "missing money" estimates (profits or losses) for a collection of representative resource types.[81] The section then examines the "missing money" for individual, representative resource types.[82]

In the chart below, scenarios are presented from left to right in the order of increasing amounts of new renewable and clean energy resource additions.

- The No Nuclear Scenarios, on the left, assumed retirement of nuclear units and, consistent with recent capacity market outcomes, replacement with natural gas-fired resources.
- In the middle of the chart, the Base Case represents the status quo – relatively modest renewable resource additions that may fall short of providing adequate RECs for current RPS targets.
- All the way to the right, the Combined Scenario added the most renewable and clean energy.

Figure 12, below, shows that **as more renewable and clean energy resources are added, "missing money" increases for *all* resources – new *and* existing resources, including renewable and clean resources**. The figure shows, from left to right, that (1) bars below zero (profits) get shorter and (2) bars above zero ("missing money" or losses) get taller. This illustrates a relationship between "missing money" and the amount of net renewable and clean energy resource additions.[83] Thus, all resources, whether low- and no-carbon resources or other resources needed for reliability, are affected economically when the region seeks to reduce power sector carbon emissions by adding renewable and clean energy resources to the region's resource mix.

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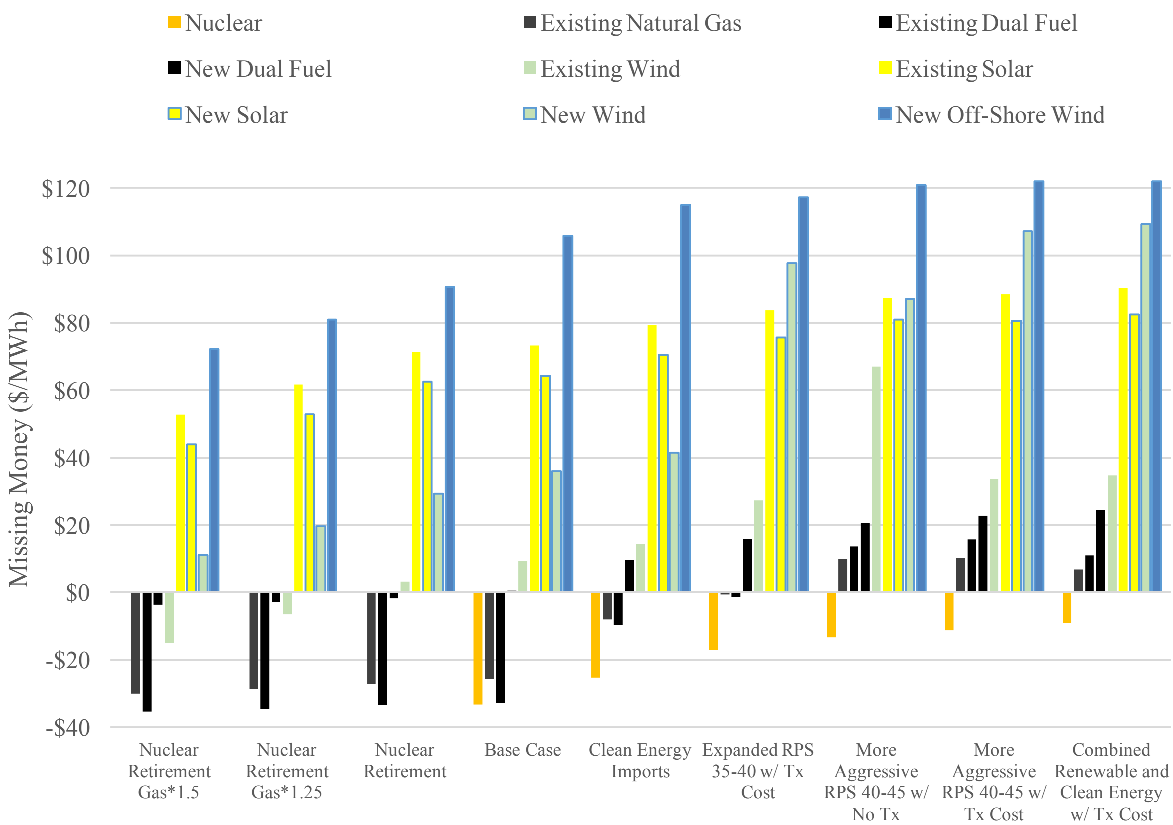
81 Other resource types, such as biomass and run-of-river hydro, are not included in Figures 12 and 13 for simplicity. The "missing money" for omitted resource types is directionally consistent with the representative resource types presented in these charts.

82 The energy and capacity price and power sector emissions results presented in section VI. Study Results are at the scenario level. While the Clean Energy Imports *scenario* includes the addition of a new clean energy imports *resource*, the actual costs of supplying the clean energy imports are not known or estimated in the study. Accordingly, these costs are not included in the missing money results.

83 As described earlier, the analysis of the missing money does not include the cost of necessary transmission upgrades to deliver on-shore wind in some scenarios. This is why wind is lower priced in some scenarios than others. Those scenarios with lower costs assume the transmission is being funded by some other means and thus the cost of transmission is not captured by the model because the owner of the wind resources itself is not responsible for covering that cost.

Figure 12: Representative Resource Types "Missing Money" Estimates Across All Scenarios (including Transmission Costs) in 2025[84]



The chart above illustrates economic impacts for resource types in New England. Recall that the study's net going forward cost estimates for existing resource types do not include so-called "avoidable" costs, like equity returns and significant capital expenditures. To the extent that equity returns and significant capital expenditures exhaust such "profits," the economic impacts illustrated in the chart would result in "missing money" (losses) at lower levels of renewable and clean energy resource additions. For example, existing natural gas-fired dual fuel resources earn profits in scenarios where nuclear resources retire (Nuclear Retirement) or add relatively modest amounts of renewable and clean energy resources (Base Case and Imports Scenarios).[85] In these scenarios, natural gas-fired resources earn higher profits from: (a) less competition from nuclear units, and (b) assumed higher gas prices. However, continuing right across the chart, existing

[84] The following charts examine the missing money results for individual resource types.

[85] As a reminder, the Nuclear Retirements Scenario retired remaining nuclear resources in New England and replaced them with 3,500 MW of additional natural gas-fired resources. The Base Case adds approximately 925 MW of new on-shore wind and 168 MW of solar PV resources by 2025, in addition to resources cleared through Forward Capacity Auction 10. The Clean Energy Imports Scenario adds approximately 1,000 MW of clean energy from a neighboring system that is assumed to be available 90% of the time over the course of a year.

natural gas-fired dual fuel resources begin to exhibit "missing money" (or losses) when significantly higher amounts of renewable and clean energy resources are added to the system.[86]

New dual fuel resources broke even, including an equity return, in the Base Case (the status quo). This is because the capacity market is designed, and continually adjusted, to provide sufficient revenues for new dual fuel resources to break even.[87] Moreover, new dual fuel resources have higher costs than *existing* natural gas and dual fuel resources.[88] Notably, scanning the chart above to the right, new dual fuel resources begin to show "missing money" (operating without profit, or in some cases losses) as the study adds renewable and clean energy resources in addition to the Base Case additions (see the Imports Scenario). This suggests new dual fuel resources may not fully receive the equity return they need to become operational. Over time, the modeling results suggest that adding new generating resources to the New England system would create a need for higher capacity prices or other revenue to make up for the decreased energy revenues.[89]

Separately, based on publicly available information, nuclear resources show profits in all scenarios in which they are assumed to remain operational.[90]

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86 The Expanded RPS 35%-40% Scenario added approximately 600 MW solar PV, 2,800 MW on-shore wind, and 1,500 MW of off-shore wind by 2025, in addition to the resources cleared through FCA 10 and assumed Base Case additions. The More Aggressive RPS 40%-45% Scenarios added 1,000 MW solar PV, 4,250 MW on-shore wind, and 2,000 MW off-shore wind by 2025, in addition to the resources cleared through FCA 10 and assumed Base Case additions. The Combined Renewable and Clean Energy Scenario adds an additional 1,000 MW of clean energy imports to the More Aggressive RPS 40%-45% Scenario's capacity additions. All values are expressed in terms of nameplate capacity.

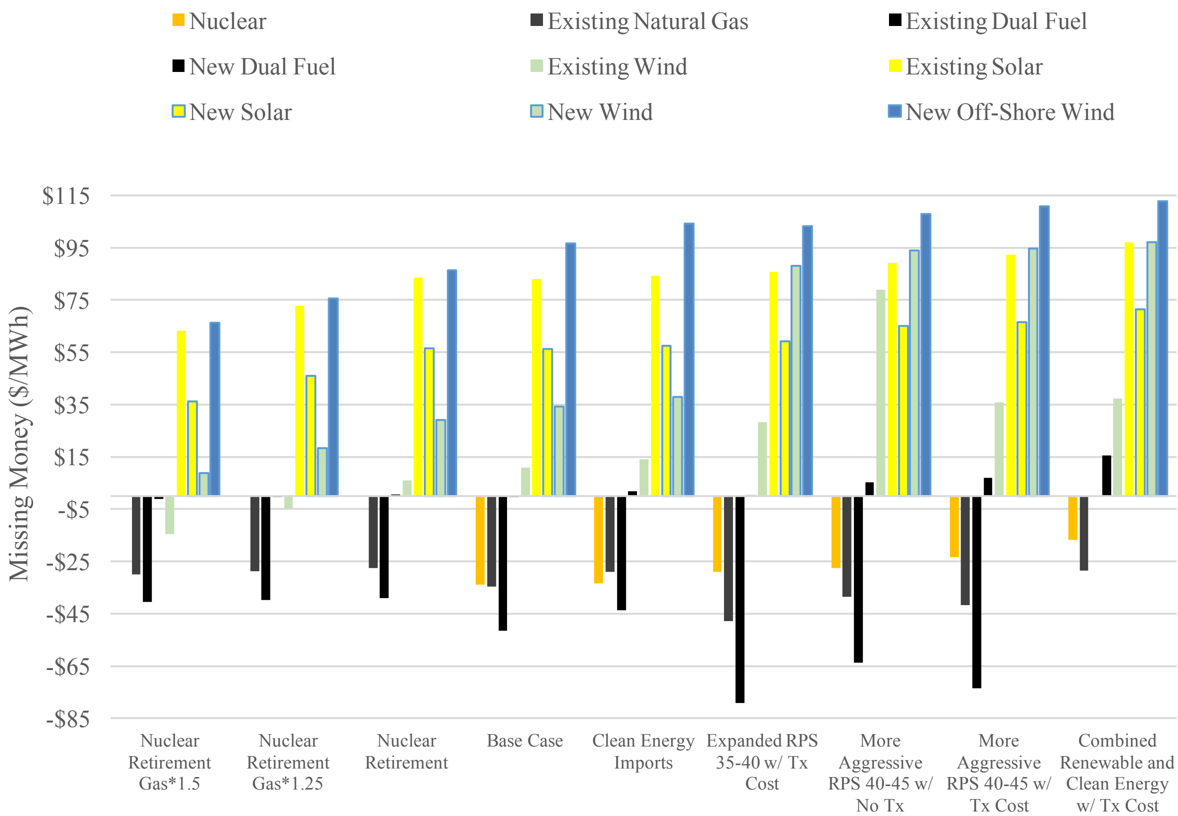
87 Technically, the capacity market is designed, and continually adjusted, to provide sufficient revenues for a new resource, which is currently a dual fuel resource. Over time, the resource type for which the capacity market is designed, and continually adjusted, to provide sufficient revenues could change to another resource type.

88 In addition to other factors that affect fixed costs, the study assumes that new resources need to earn the all-in going forward fixed costs, which does include equity returns.

89 Phase II of the study will compare and contrast selected mechanisms that states could use to support certain hypothetical future expansions of renewable and clean energy resources and associated infrastructure.

90 Nuclear resources were assumed retired in the Nuclear Retirements Scenario and associated gas price sensitivities. Also*, see* Section II: Study Limitations and Section V: Study Approach for a discussion of net going forward costs for existing units (i.e., return on equity is not included in the "missing money" estimates for existing units). Notably, in all scenarios in which they are assumed to remain operational, the region's two remaining nuclear resources earned market-based revenues in excess of an assumed 12.5% return on equity and an annual $8/MWh capital expenditure schedule in 2030.

Figure 13: Representative Resource Types "Missing Money" Estimates Across All Scenarios (including Transmission Costs) in 2030



The chart above presents the same information for 2030. "Missing money" (losses) is lower in 2030 than it was in 2025. Renewable and clean energy resource additions to the capacity market delayed the market price's return to a level that provides sufficient revenues over time for new dual fuel resources. This means that as capacity market prices increase over time, so do profits. By 2030, in almost all scenarios, capacity prices increased from their earlier decline that resulted from renewable and clean energy resource additions.

The higher capacity market prices in 2030 result in shorter bars on the top part of the chart (the amount of "missing money") for all resources. For existing and new natural gas fired resources, the effect of the higher capacity prices in 2030 means the difference between profits (in 2030) and losses (in 2025, shown in the chart above by the dark bars above zero). **This emphasizes the contribution of capacity revenues to the "missing money" for existing and new natural gas and dual fuel resources**. These results illustrate how the energy and capacity markets are interrelated – lowering prices in the energy market is likely to increase prices in the capacity market. Moreover, **mechanisms to support *new* renewable and clean energy resources may have the unintended consequence of increasing the "missing money" for *existing* renewable and clean energy resources**. Phase II of the study will compare and contrast mechanisms states could use to support renewable and clean energy resources and associated infrastructure.

The next several charts show the impact of renewable and clean energy resource additions on the individual resource types' "missing money" estimates in 2025 and 2030. For resources like existing natural gas and new dual fuel, the difference between "missing money" in 2025 and in 2030 is significant. This is another illustration of the importance of capacity prices to these resources. In contrast, renewable and clean energy resources' "missing money" amounts appear to be much less sensitive to capacity market revenues, since they earn a much greater share of their revenues from the energy market.

Figure 14: Existing Natural Gas Resources' "Missing Money" Estimates Across All Scenarios in 2025 and 2030

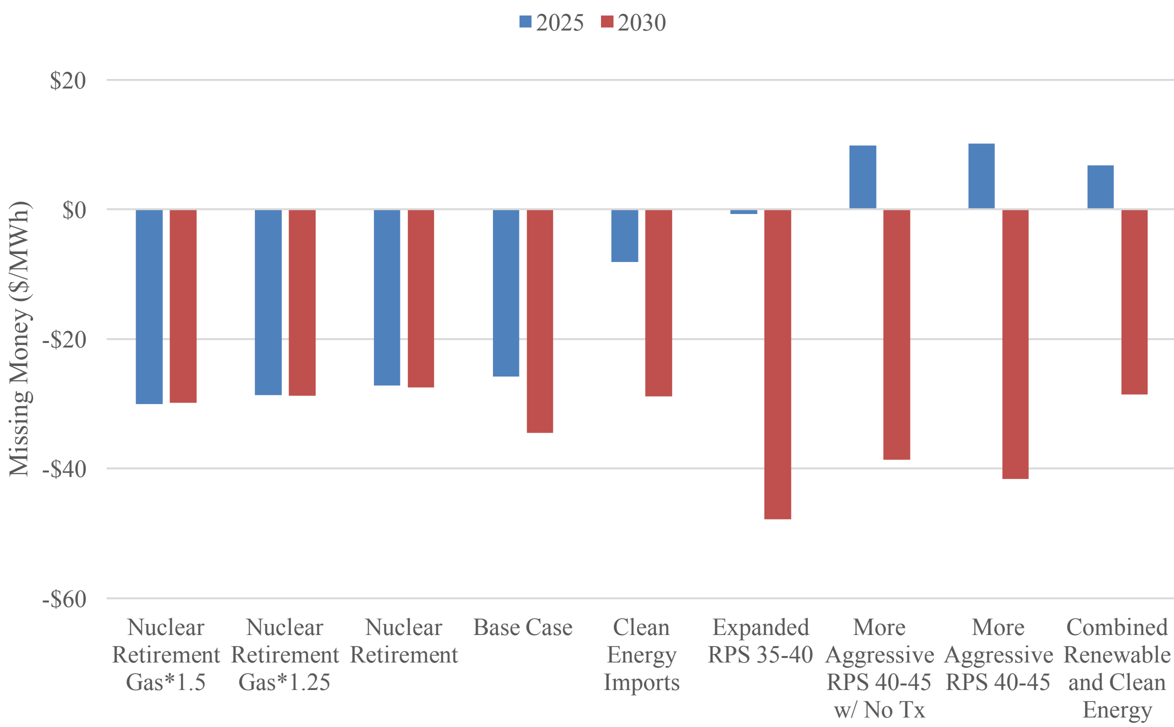
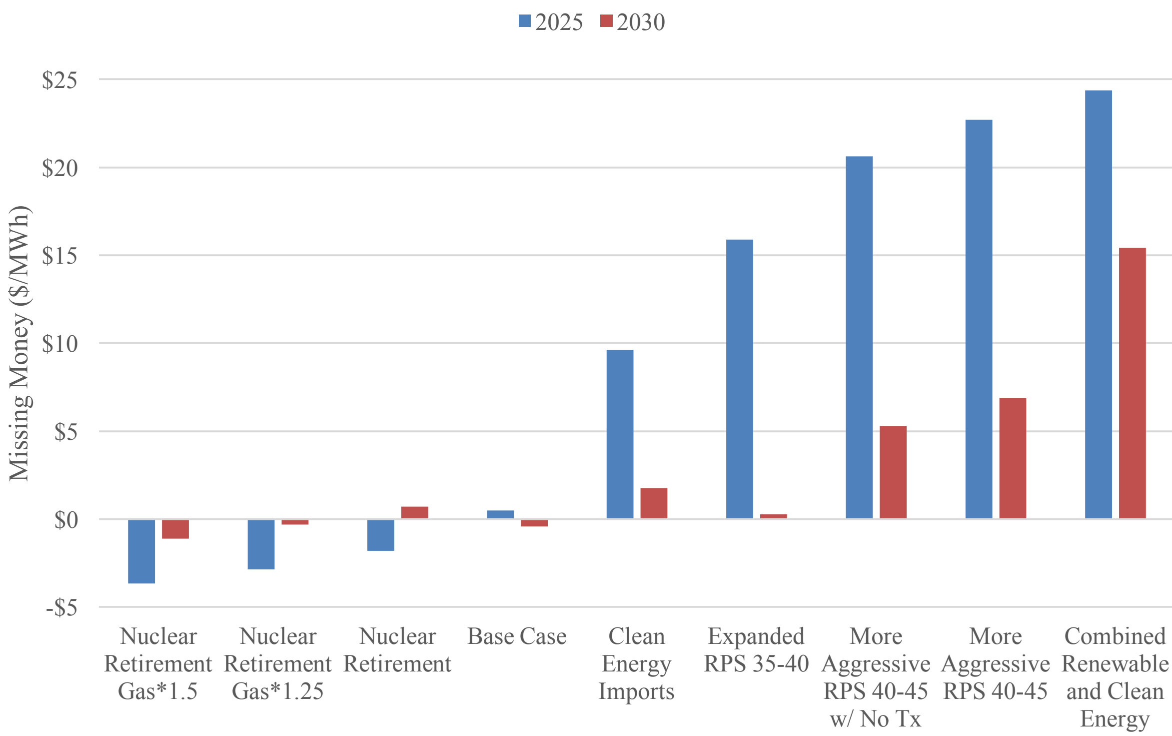


Figure 14: New Dual Fuel Resources' "Missing Money" Estimates Across All Scenarios in 2025 and 2030



New dual fuel resources have "missing money" in scenarios that add renewable and clean energy resources in 2025 and 2030. This shows that new dual fuel resources may not be able to provide a sufficient return on equity in scenarios that add such resources despite 2030's increased capacity prices.

The next two charts illustrate the impact of adding more renewable and clean energy resources on the "missing money" for *existing* renewable resources. The "missing money" for *existing* renewable resources *increases* with the addition of other renewable and clean energy resources. Conversely, the "missing money" amounts decrease with nuclear retirements and increased gas prices. This effect illustrates the reliance on energy market revenues for renewable resource types.

Figure 16: Existing Solar PV Resources' "Missing Money" Estimates Across All Scenarios in 2025 and 2030

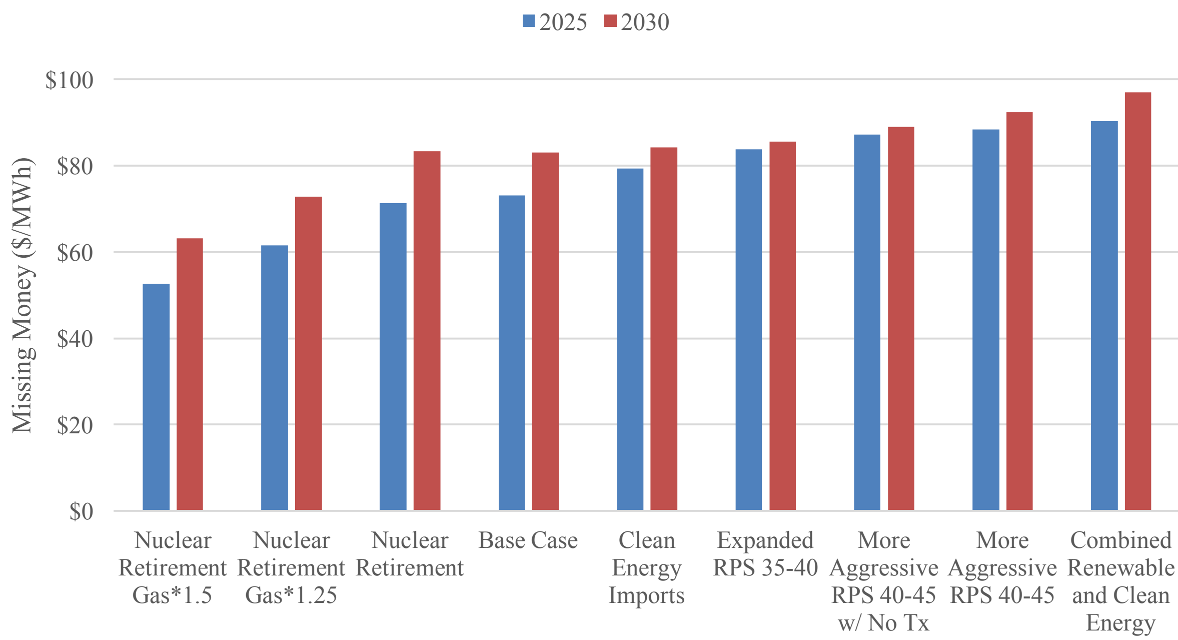
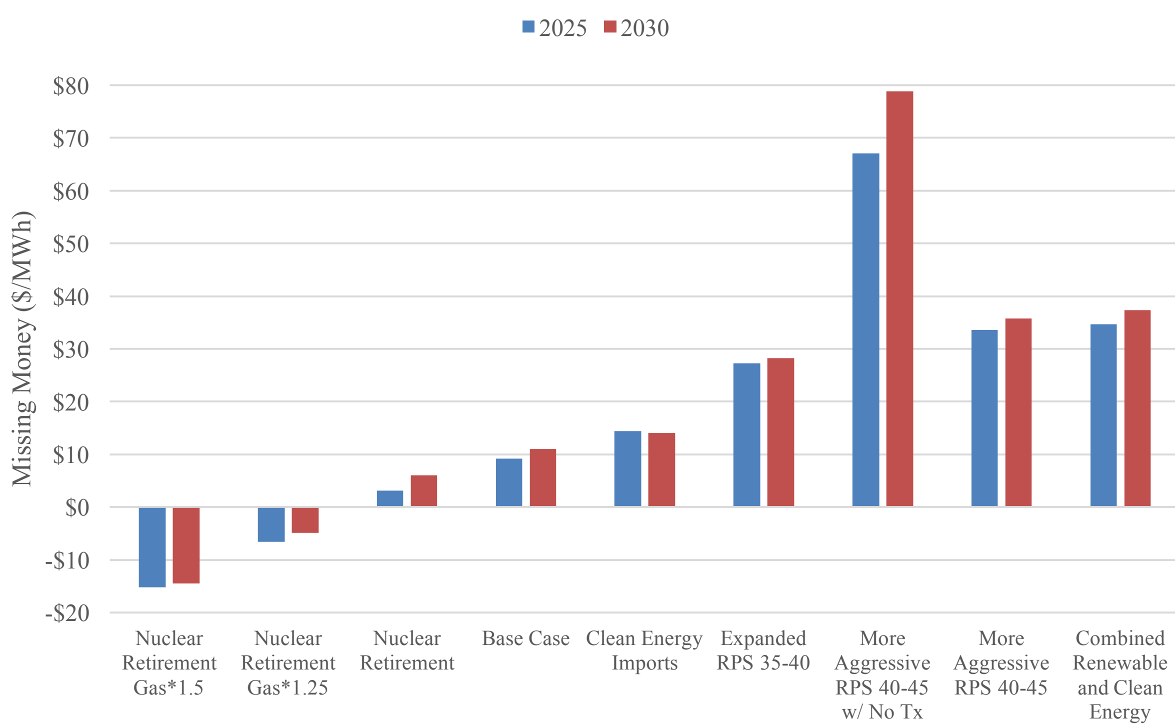


Figure 17: Existing On-Shore Wind Resources' "Missing Money" Estimates Across All Scenarios in 2025 and 2030



1. On-Shore Wind Resources Require Transmission To Be Deliverable and Economic

The next section is focused on transmission to enable delivery of new on-shore wind resources. The table below describes the treatment of transmission in the Expanded RPS Scenarios: (1) whether the transmission for deliverability is assumed to be built (modeled), and (2) how transmission costs are paid for.

Recall that the study presents transmission costs in two ways (a) through some means outside of the market such as through one or more states agreeing voluntarily to consumers funding transmission,[91] and (b) paid for by the new on-shore wind resource through its interconnection and included in the "missing money" estimates.[92]

The Aggressive Scenario's hypothetical 3,600 MW high-voltage direct current ("HVDC") transmission configuration to deliver new on-shore wind resources is estimated to cost, at a high level, approximately $5.65 billion, or $43-$54/MWh. The Expanded Scenario's hypothetical 2,400 MW HVDC transmission configuration to deliver new on-shore wind resources is estimated to cost, at a high level, approximately $3.8 billion, or $42-$49/MWh.

Each expanded RPS scenarios, except for the No Transmission Scenario, assumed that transmission for new on-shore wind resources would be built. The No Transmission Scenario examined the implications of not building the transmission necessary to deliver new on-shore wind power to customers in New England. This last scenario is not necessarily a plausible outcome per se, but is included to provide information about transmission constraints and resource curtailment.

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91 An example of an alternative funding mechanism is a participant funded Elective Transmission Upgrade ("ETU").

92 The More Aggressive RPS 40%-45%'s hypothetical 3,600 MW HVDC transmission configuration to deliver new on-shore wind resources is estimated to cost, at a high level, approximately $5.7 billion. On an annual basis, this would equal approximately $911 million. Charging the costs of the transmission to the new on-shore wind resources in the More Aggressive RPS 40-45 Scenario adds approximately $43-$54/MWh to the "missing money" for this resource type. See Appendix A for more information. Similarly, the Expanded RPS 35-40's hypothetical 2,400 MW HVDC transmission configuration to deliver new on-shore wind resources is estimated to cost, at a high level, approximately $3.8 billion. On an annual basis, this would equal approximately $608 million. Charging the costs of the transmission to the new on-shore wind resources in the Expanded RPS 35-40 Scenario adds approximately $42-$49/MWh to the "missing money" for this resource type.

Table G: Expanded RPS Scenarios and Treatment of Transmission for New On-shore Wind Resources

Scenario:	Transmission for Deliverability[93]	Assumption of Transmission Costs Responsibility[94]
Expanded RPS 35%-40%	Included in the Model (assumes adequate transmission has been built), Enabling Renewable Energy Delivery	Outside of the Markets as an Elective Transmission Upgrade ("ETU") or Public Policy Project
		Paid for by New On-Shore Wind Resources in their interconnection agreements
More Aggressive RPS 40%-45%	Included in the Model (assumes adequate transmission has been built), Enabling Renewable Energy Delivery	Outside of the Markets as an ETU or Public Policy Project
		Paid for by New On-Shore Wind Resources in their interconnection agreements
More Aggressive RPS 40%-45% without Transmission	Not modeled, resulting in Congestion and Curtailments	None

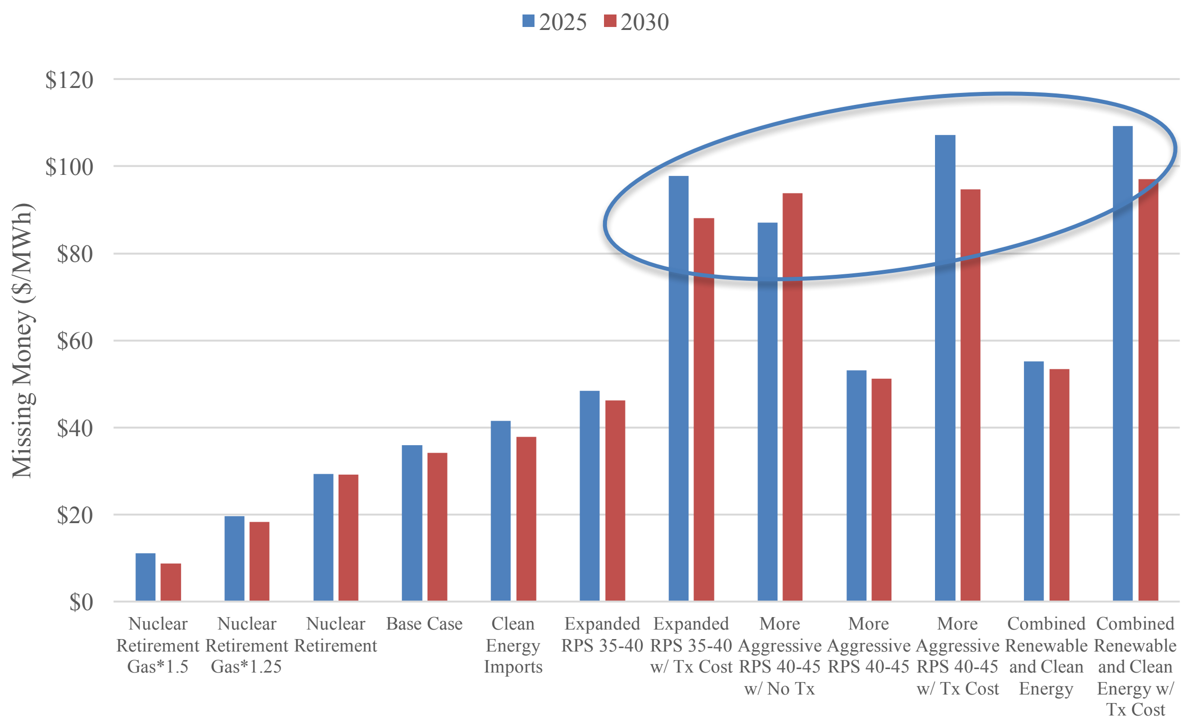
The chart below highlights the impact of transmission and associated cost responsibility on the "missing money" for *new* on-shore wind resources. The oval on the graphic spotlights that transmission - availability and cost responsibility - has a significant impact on new on-shore wind resources deliverability and relative economic competitiveness.[95]

93 See Appendix A for more information on the hypothetical 3,600 MW HVDC transmission lines that enable deliverability for new on-shore wind resources.

94 Also see Appendix A for more information on the estimated costs associated with the hypothetical 3,600 MW HVDC transmission lines that enable deliverability for new on-shore wind resources.

95 As shown above, the More Aggressive RPS 40%-45% without Transmission Scenario also has higher power sector carbon emissions than the More Aggressive RPS 40%-45% with Transmission Scenarios.

Figure 18: New On-Shore Wind Resources' "Missing Money" Estimates Across All Scenarios in 2025 and 2030



In the No Transmission Scenario, ISO-NE system operators would have to curtail (turn off) new on-shore wind due to transmission constraints. Turning off new on-shore wind resources because of transmission constraints results in higher "missing money" estimates for new on-shore wind (compared to the Aggressive Scenario, which assumes additional transmission). This is because transmission constraints prevent new on shore wind energy from delivering energy and that reduces energy market revenues. Indeed, under the study's assumptions, **the lack of associated transmission to enable deliverability almost doubled the "missing money" for *both* new and existing on-shore wind resources**. This is because both new and existing on-shore wind resources are mostly located in the same portion of the system. The transmission constraints that impede new on-shore wind would also adversely impact existing on-shore wind resources.

Similarly, the Expanded and Aggressive assume adequate transmission has been built (include sufficient transmission in the model) to deliver new on-shore wind energy. The results for these scenarios are presented in two ways: (1) assuming the costs of transmission for new on-shore wind resources are paid for outside the market, such as for example, by one or more states agreeing voluntarily to pay the costs through an Elective Transmission Upgrade; and assuming the costs are paid by the new onshore wind resources as part of their interconnection agreement and added to the "missing money" for new on-shore wind resources.[96]

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[96] This study does not make assumptions about how transmission to reach renewables and clean power might be funded.

Presenting the results in this fashion highlights how generators paying for transmission costs almost doubles the "missing money" for new on-shore wind resources. This is because the "missing money" calculation for this resource includes both generation *and* transmission costs. Importantly, **if new on-shore wind resources pay for the transmission costs needed to interconnect their resources, their "missing money" will be in excess of assumed future ACP levels ($80 in 2025 and $88 in 2030)**. Without additional transmission upgrades, some new on-shore wind resources in congested areas are unlikely to be permitted to connect to the system. Moreover, lack of transmission headroom reduces opportunities for new on-shore wind resources to sell power and earn revenues. Reduced revenue opportunities will increase the need for support through other means, such as long-term contracts. Without new transmission paid for by consumers at the direction of one or more states on a voluntary basis, the model shows that new on-shore wind would not earn enough money from the markets plus programs such as RPS (given current ACP levels) to be profitable.

Appendix A: Hypothetical Transmission to Deliver Additional On-Shore Wind Resources

The Expanded RPS and Combined Scenarios assume an additional 4,250 MW in 2025 and 5,500 MW in 2030 of on-shore wind resources hypothetically located in the Maine portion of the system. The study shows the performance and economics associated with the wind turbines, but does not explicitly include a cost for the transmission.

To estimate the cost of transmission associated with delivering new on-shore wind resources to electricity customers in New England, it is necessary to develop a hypothetical transmission plan. NESCOE prepared this Appendix for that purpose. The scenarios do not suggest that new on-shore wind resources that require transmission are the only resources that could satisfy expanded renewable goals.

Based on a highly simplified cost estimating approach, discussed in detail below, the forecasted cost for three 1200 MW HVDC transmission lines radially connected to the hub is approximately $5.65 Billion, or $54/MWh in 2025 and $43/MWh in 2030. Similarly, the forecasted cost for two 1200 MW HVDC transmission lines radially connected to the hub is approximately $3.8 Billion, or $49/MWh in 2025 and $42/MWh in 2030. This appendix sets forth a hypothetical transmission plan and simplified transmission cost based on: (a) capital costs associated with HVDC converter stations, expressed in cost per converter station, and (b) capital costs associated with HVDC transmission lines, expressed in cost per mile.

In the study, these new resources and transmission lines are represented as being located in the Central Massachusetts zone. As the wind resources are "above market," the costs of the associated HVDC transmission lines would not likely affect which resources ISO-NE's market selects to supply energy, and, therefore, would not likely affect the modeling results, which estimate the market-based revenues. However, most on-shore wind resources in the queue are located in the northern part of New England, not in the Central Massachusetts zone. The cost of transmission upgrades associated with interconnection and delivery to these resources is substantial. Traditionally, these costs are paid for by the resource as part of their interconnection agreement. Most likely, the costs of such transmission lines would be added to the above-market costs, or "missing money" estimates for new on-shore wind resources. As the "missing money" estimates for new on-shore wind resources are expressed in both an annual amount and in a per unit of production, the cost of the transmission could be added to these estimates.

2. Hypothetical Transmission Plan

New transmission infrastructure would be necessary to deliver the additional on-shore wind energy assumed in the Expanded RPS Scenarios. Currently, there are several indicators that additional transmission infrastructure: (1) would facilitate delivery of the current amount of renewable energy and (2) is necessary in the assumed scenarios to accommodate the amount of renewable energy required by current laws and regulations.[97] Enabling delivery of the additional

[97] For example, renewable energy certificates for new resources have been trading at the alternative compliance payment level in most New England states for several years. *See* Lawrence Berkeley National Laboratory's RPS Annual Status Report 2016, at slide 28, available at https://emp.lbl.gov/sites/all/files/lbnl-1005057.pdf. In addition, compared to all of the other ISO/RTOs,

on-shore wind to the center of the New England system would require an assumed expansion of transfer limits through four major AC system interfaces: Orrington South, Surowiec South, Maine-New Hampshire, and North-South; or alternatively DC lines that deliver power directly into southern New England. Based on the characteristics of the New England system, expanding the AC system to accommodate delivery of an additional 4,250 to 5,500 MW of on-shore through four major interfaces would be complicated and expensive. However, hypothetically, HVDC lines connected radially to the center of the New England system could enable significant deliverability, bypassing the AC system interface constraints in the process. Since the complexity associated with an AC solution would require significant engineering studies, very high level, non-specific cost estimates work better for HVDC than for AC and so those high level estimates are used here.[98]

a) Establish Power Rating and Number of Transmission Lines

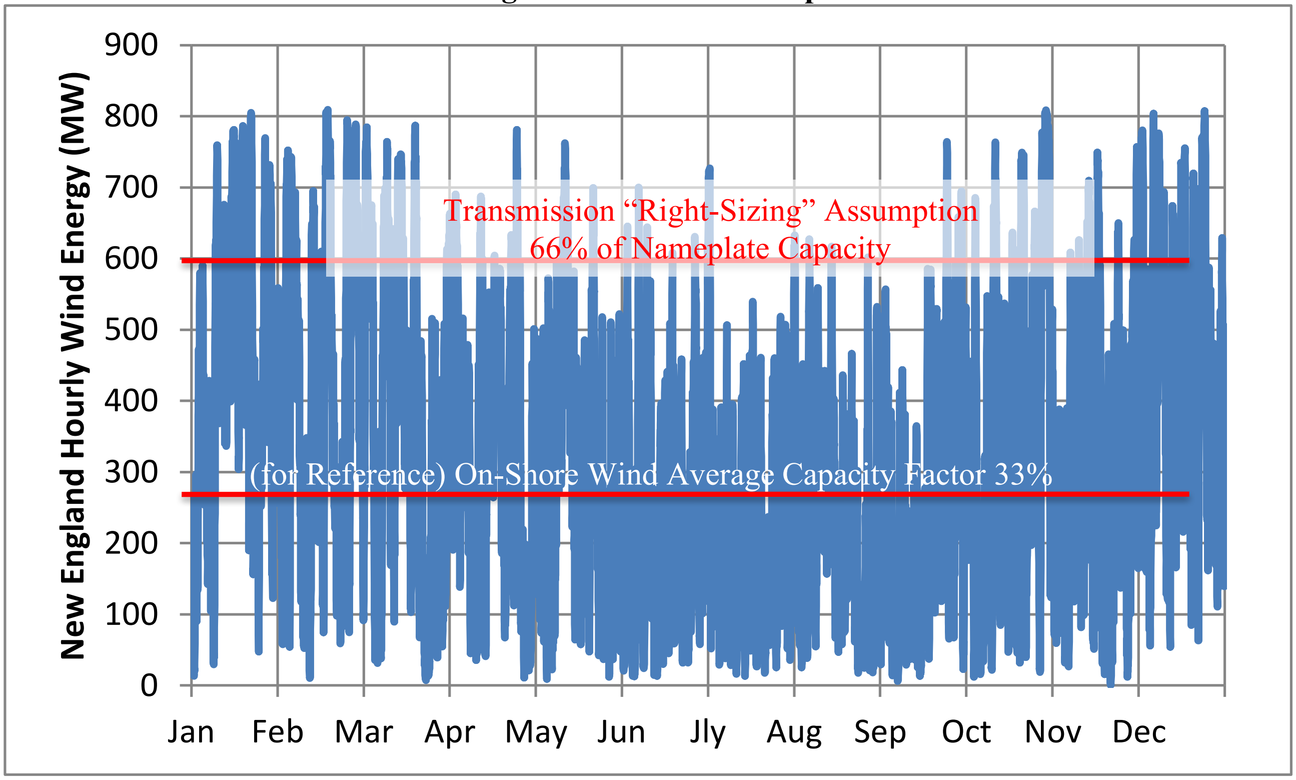
The study assumes an additional 5,500 MW of on-shore wind resources by 2030. To deliver the output from this additional on-shore wind, it is necessary to design a proportional amount of transmission infrastructure. Ideally, the transmission infrastructure would be "right sized" to optimally use the transfer capability at the lowest cost. However, on-shore wind resource output varies with the speed of the wind and currently New England[99] wind has an annual average capacity factor of 33%. In addition, New England's system planning guidelines and agreements with neighboring systems would limit the size for each new hypothetical DC transmission line to 1,200 MW. Considering these objectives, a power rating somewhere between the average annual (capacity factor) and maximum output (nameplate) capability is appropriate. For example, a combined 3,600 MW of additional hypothetical transfer capability would facilitate delivery of approximately two-thirds (66%) of the assumed 5,500 MW incremental nameplate on-shore wind capacity in 2030. Figure 19 below illustrates the degree of deliverability from such an amount of transmission on the existing amount of on-shore wind in New England (878 MW, as of 4/1/2015).

New England receives the least amount of capacity credit for its renewables, despite being in the middle of the pack in terms of energy contribution from renewables. *See* RTO Metrics Report Summary, at slide 7, available at http://nescoe.com/wp-content/uploads/2015/11/ISO-RTO_Metrics_25Nov2015.pdf. Current wind resource curtailment issues in New England are well known, and with approximately 3,000 MW of *additional* wind resources (or other eligible resources) needed to meet *current* RPS laws and regulations by the end of the study period, under the hypothetically expanded RPS targets, additional transmission will be necessary in the modeling to deliver the energy to customers. Importantly, the Base Case assumes no new transmission, which limits the amount of on-shore wind that can be interconnected in northern Maine and delivered to customers in the rest of the system. The Base Case results include a shortfall of RECs in comparison to current RPS laws and regulations.

98 This approach estimates a necessary, but not sufficient, amount of transmission system enhancements necessary to deliver new on-shore wind resources.

99 The economic modeling of the energy market assumes a 37% capacity factor for on-shore wind resources to reflect technology improvements over the next 10 to 15 years.

Figure 19: Illustration of Transmission "Right-Sizing" Assumption
Existing On-Shore Wind Output



Source: ISO New England, Wind Integration Studies

As Figure 19 illustrates, a 66% "right-sizing" assumption would: (1) at times, be insufficient for some of the assumed incremental on-shore wind and would likely result in some curtailments, and (2) at other times, be more than sufficient and result in excess transmission capacity.[100] Moreover, adding a fourth 1,200 MW DC would not likely be an economically efficient means to integrate 5,500 MW of on-shore wind. Thus, the study assumes three (3) 1,200 MW DC lines connected radially to the center of the New England system would enable significant deliverability.

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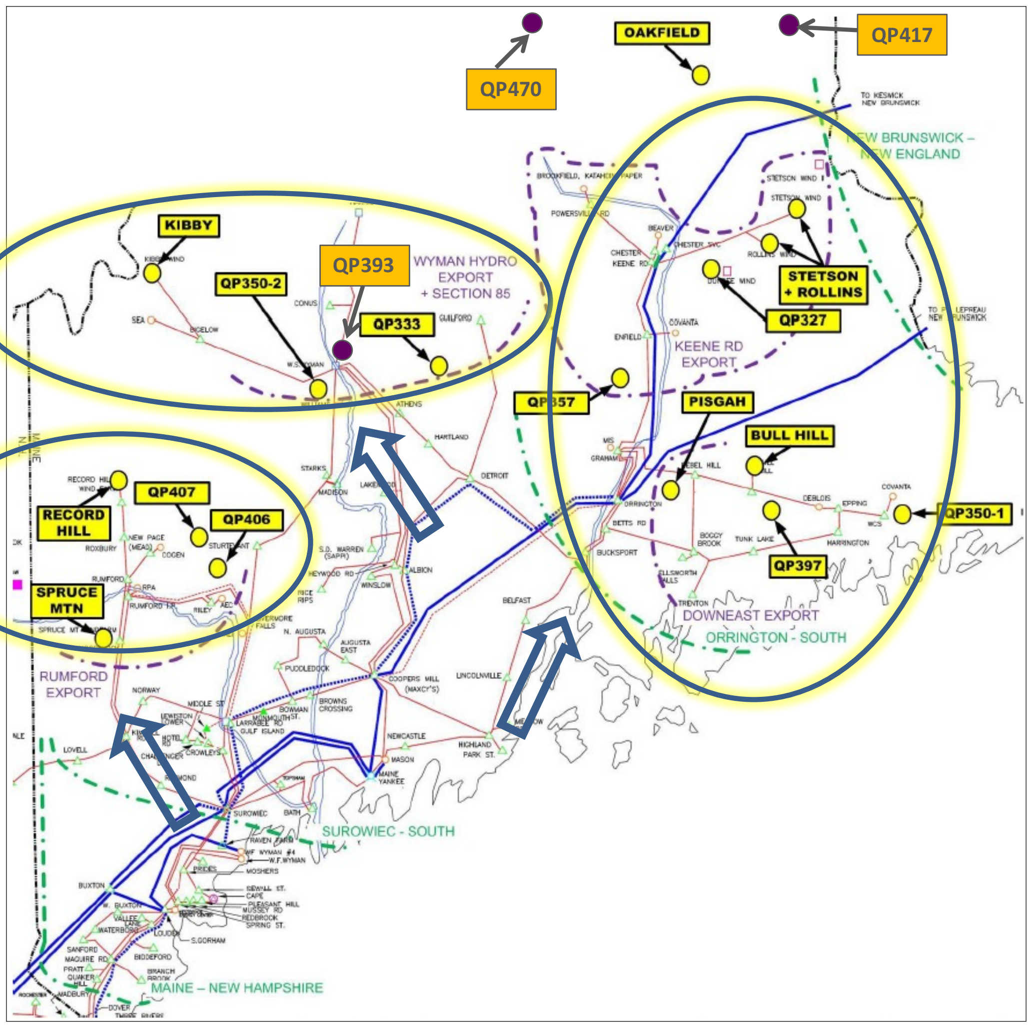
100 An important limitation of analysis is that the per unit cost is based on production from economic model that assumed the generation would be physically located within the central mass zone ~ a proxy for the hub. This was done because electrically, it would operate in this fashion. However, there are hours in the year when the production from these resources would exceed the capacity of the hypothetical DC lines due to intermittency and the sizing of the line relative to the nameplate capacity of the generation. Thus, there may be a downward bias to the per unit estimates. However, in the real world, the HVDC transmission lines could be utilized to enable greater throughput between Maine and the hub when the dedicated new generation facilities would not be using the full capacity of the lines. Additional power from existing renewables in this location and potential increases in power from the New Brunswick ties could, in theory, help utilize available capacity. Therefore, the issue is one of potentially limited impact. For the illustrative purpose of the study, and given the simplified cost estimates, the hypothetical transmission infrastructure and associated cost estimates are intended to be within the range of reasonableness.

1,200 MW per transmission line is generally consistent with current limits of the technology and with current operational restrictions on the size of the largest single contingency, especially considering the study's timeframe.[101]

b) Envision Conceptual Transmission Projects

In New England, most of the on-shore wind projects in the interconnection queue are located in Maine. The queue represents the development community's perspective on the most attractive sites to develop on-shore wind resources. As shown in the graphic below, these sites are located throughout the state of Maine with relative proximity to three locations on the New England transmission system (from left to right): Rumford, Wyman, and Orrington (between Keene Rd and far northeastern Maine – identified in the graphic below as the "Downeast Export" location).

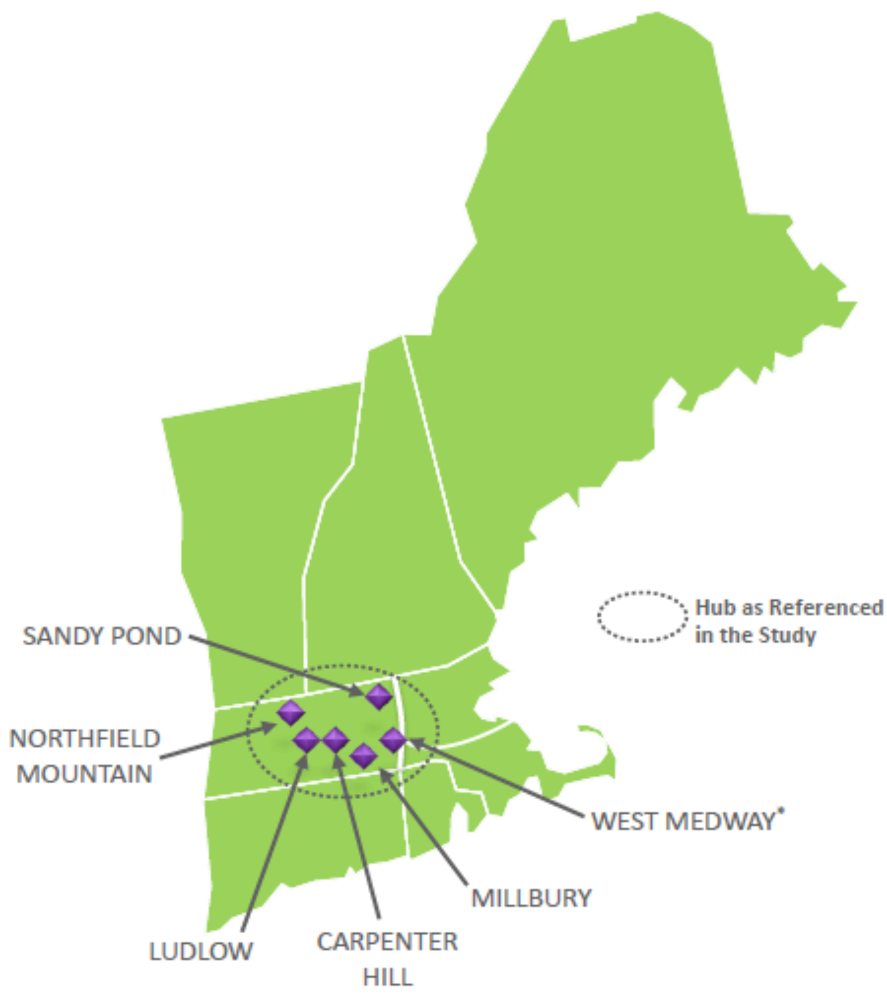


Source: ISO New England 2015 Economic Study: Strategic Transmission Analysis – Onshore Wind Integration, Figure 2-4 at 11.

101 Transmission lines rated +/- 320 kV DC with symmetric monopole configuration can transfer approximately 1100 MW with current voltage source converter technology. Higher transfer amounts are theoretically possible, and 1200 MW transfer capability is within the range of reasonableness by 2025.

As these three wind-rich areas indicate where the resources are located, the study assumes the point of origination for three 1,200 MW HVDC transmission lines are in or near the vicinity of Rumford, Wyman, and Orrington, Maine.

Similarly, it is necessary to identify a general location for delivery of the power that will enable it to reach the most electricity customers and minimize impacts on the AC transmission system's operation. Such a location on the transmission system is called "the hub." The hub is a theoretical group of locations in the robust center of the region's transmission system. From here, HVDC lines from wind-rich areas of Maine could be hypothetically interconnected with relatively low impact on the region's AC transmission system in a radial configuration. The graphic below illustrates the hub concept and identifies locations that are part of the hub.



Source: ISO New England 2012 Strategic Transmission Analysis - Generation Retirements Study, at slide 27.

As locations to deliver on-shore wind power to all New England customers at the hub, the study assumes the following approximate locations as the points of termination for the three hypothetical 1,200 MW HVDC transmission lines (left to right): Northfield Mountain, Millbury, and Sandy Pond. Conceptually connecting three wind areas to hub locations results in the study's hypothetical transmission infrastructure for delivering additional on-shore wind energy.

Project A: Orrington, ME to Millbury, MA (approximately 260 miles)

Section 1: Orrington, ME to Searsport, ME ~ 25 miles
Section 2 (submarine): Searsport, ME to Boston, MA ~ 190 miles
Section 3: Boston, MA to Millbury, MA ~ 45 miles

Project B: Wyman Substation in Moscow, ME to Sandy Pond in Ayer, MA (approximately 230 miles)

Project C: Rumford, ME to Northfield, MA (approximately 250 miles)

3. Simplified Transmission Cost Estimate

The study uses a highly simplified approach to estimate the costs of HVDC transmission infrastructure. Consistent with the method used in an interconnection-wide U.S. Department of Energy funded planning exercise in 2012, the study estimates a cost per mile and a cost per converter terminal as the basis for a project cost estimate.[102] In keeping with the illustrative nature of this study, the simplified transmission cost estimate developed below is intended to provide useful information, but should not be interpreted as comprehensive or precisely accurate.

a) Transmission Lines

The actual cost of constructing and installing HVDC transmission lines varies widely from project to project, region by region, and is influenced by factors such as land acquisition costs, terrain, overhead/underground/submarine configurations, proximity to environmentally sensitive areas, local land use patterns, etc. Accordingly, there is a wide range of costs per mile for a hypothetical project. The study relies upon a recent engineering analysis performed for ISO-NE and presented to the region's Planning Advisory Committee to develop capital cost estimates for the transmission lines in the New England region.

i. Cost per Mile

According to the Greater Boston Solutions Study, the cost of DC submarine and land cables is approximately \$2.153M per mile.[103] However, the Greater Boston Solutions Study estimates the cost of installing associated AC cables to be "\$8 Million dollars per mile based on industry experiences in the Northeast."[104] Therefore, the cost per mile of installing this study's hypothetical HVDC transmission project is likely somewhere between \$2.153 M and \$8 M per

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102 For more information, see http://www.eipconline.com.

103 Electrical Consultants, Inc., Greater Boston Solutions Study; Cost Reviews, October 2014 ("Greater Boston Solutions Study"), at 4-1, available at https://www.iso-ne.com/static-assets/documents/2014/12/a4_eci_greater_boston_solution_study_cost_review_redacted.pdf.

104 Greater Boston Solutions Study, at 4-2.

mile. For simplicity, this study assumes the midpoint between these estimates, resulting in a cost estimate of $5M per mile. For reference, the Greater Boston Solutions Study also applies a 20% adder for submarine cables, which tend to be approximately 70% of the installation cost. Accordingly, this study assumes submarine cables cost 14% more (20% * 70% = 14%) than land-based cables, resulting in a cost estimate of $5.79 M per mile for submarine sections.[105]

ii. Cost per Line

The table below shows the various sections of the study's hypothetical HVDC transmission infrastructure projects with the associated cost per mile estimates applied. The approximate section length is then multiplied by the relevant cost per mile estimate.

	Sub-Section	Length	Cost / Mile	Sub-Total	Total (M)
Project A	Section 1	25	$5	$125	$1,450
	Section 2	190	$5.79	$1,099	
	Section 3	45	$5	$225	
Project B		230	$5		$1,150
Project C[106]		250	$5		$1,250

b) Converter Stations

At each end of the hypothetical DC transmission line is a converter terminal, which changes the power from / back into alternating current and connects / reconnects the line into the AC network. These converter stations are relative expensive, which is why DC is typically only used in long-distance and/or electrically complex applications. The study relies upon a host of publicly available converter station cost estimates to develop a range of potential costs per MW rating values. The study then applies a conservative per MW estimate to the hypothetical transmission project ratings to arrive at an estimated cost per DC converter terminal.

i. Cost per MW

The table below lists publicly available converter station estimates. These estimates are from projects of various sizes and different regions of the country over the past several years. For simplicity, the relatively older cost estimates have not been inflated to reflect the time value of money. The cost estimates are then divided by MW rating of the facility to enable comparison.

105 *Id.*

106 The Expanded RPS 35%-40% Scenario requires 2,400 MW of HVDC and does not include Project C.

Source	Rating (MW)	Cost Estimate	Imputed $/kW
ISO-NE for Governors Study - Aug 2009[107]	1,500	$270,000,000	$180
ABB for Champlain Hudson Power Express (CHPE) - March 2010[108]	1,000	$207,000,000	$207
Black & Veatch (B&V) for Sharyland (TX) - Loma Alta - June 2011[109]	1,000	$150,000,000	$150
Eastern Interconnection Planning Collaborative - Sep 2012[110]	3,500	$275,000,000	$79
TRC for CHPE - Oct 2013[111]	1,000	$200,000,000	$200
B&V for NESCOE - Nov 2013[112]	1,200	$300,000,000	$250
B&V for TEPPC/WECC - Feb 2014[113]	3,000	$506,779,350	$168
B&V for TEPPC/WECC - Feb 2014	3,000	$460,708,500	$154
ECI for ISO-NE (Greater Boston) - Oct 2014[114] (Vendor Pricing – Turn Key Approach)	520	$145,850,000	$280
ECI for ISO-NE (Greater Boston) - Oct 2014 (TransBay Comparison Approach)	520	$128,000,000	$246

Based on the information in the table above, the average cost per kW of all of the estimates is approximately $191/kW. Focusing only on the estimates for projects in the Northeast, the

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107 ISO New England August 14, 2009 presentation to Planning Advisory Committee, New England 2030 Power System Study: Preliminary Maps and Cost Estimates for Potential Transmission, at slide 15, available at http://nescoe.com/uploads/prelim_trans_and_cost_estimates_new_maps.pdf.

108 March 30, 2010 Application of Champlain Hudson Power Express, Inc. pursuant to Article VII for Certificate of Environmental Compatibility and Public Need in New York Public Service Commission Case 10-T-0139, Exhibit 9, at 9-2: Cost of Proposed Facility, available at http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={C8D002F3-5251-493F-B3AA-15261EFF5922}.

109 Black & Veatch June 17, 2011 presentation to Electric Reliability Council of Texas Regional Planning Group meeting, Sharyland Loma Alta HVDC Project, at slides 18-19, available at http://www.ercot.com/content/meetings/rpg/keydocs/2011/0617/HVDC_Assessment_06-17-11_RPG_PART_2.pdf.

110 September 20, 2012 Presentation to Stakeholder Steering Committee of the Eastern Interconnection Planning Collaborative, U.S. Department of Energy-Funded Phase II Modeling Results Task #10, Transmission Cost Estimate Matrices, available at http://www.eipconline.com/modeling-results-1.html.

111 TRC Solutions, October 2013, Cost and Feasibility Analysis of a Third Converter Station for the Champlain Hudson Power Express Project, at 6, available at http://www.chpexpress.com/docs/Champlain_Hudson_Third_Converter_Station_Final_Report.pdf.

112 Black & Veatch, Hydro Imports Analysis, November 2013, at 5-1, available at http://nescoe.com/wp-content/uploads/2015/08/HydroImportsAnalysis_1Nov2013.pdf.

113 Black & Veatch, Capital Costs for Transmission and Substations: Updated Recommendations for Western Electricity Coordinating Council Transmission Expansion Planning, February 2014, at 3-4, available at https://www.wecc.biz/Reliability/2014_TEPPC_Transmission_CapCost_Report_B+V.pdf.

114 Greater Boston Solutions Study, at 4-6.

average cost per kW is approximately $222/kW. If the oldest, Northeast-based estimate is removed from the sample, the average cost per kW is approximately $237/kW. Applying a conservative approach, the study assumes $250/kW for the cost of an HVDC converter terminal, which is consistent with an estimate provided to NESCOE in 2013 and between two estimates provided in the Greater Boston Solutions Study analysis.

ii. Cost per Station

The study assumes the hypothetical transmission projects would be rated at 1,200 MW. Applying the $250/kW cost estimate assumption to a 1,200 MW converter terminal results in a cost per station of approximately $300 Million.

iii. Converter Station Costs

As there are three hypothetical projects with a converter station at each end of the line, a total of six converter terminals are assumed. At $300 Million per terminal, the total cost of the six converter stations is $1,800 Million.

c) Total Cost for the More Aggressive RPS 40%-45% Scenario

The table below shows the total cost of the transmission lines and converter stations for the More Aggressive 40%-45% Scenario.

	Length	Transmission Line ($ M)	Converter Stations ($ M)	Total Capital Costs ($ M)
Project A	260	$1,450	$600	$2,050
Project B	230	$1,150	$600	$1,750
Project C	250	$1,250	$600	$1,850
			Grand Total	**$5,650**

The total, upfront capital cost of all three hypothetical projects is approximately $5.65 Billion. To convert the total capital cost into an annual amount, the study employs an approach that uses a set percentage of the capital cost amount is a reasonable proxy for an annual carrying cost. Specifically, the study assumes that 16% of the total capital cost is a reasonable proxy for an annual carrying cost.[115] Applying the 16% annual carrying cost assumption to the total capital cost estimate of $5.65 Billion results in a $904 Million annual cost.

To convert an annual hypothetical transmission cost to a per unit of energy basis, the study divides the annual carrying cost by the energy output of the new on-shore wind resources. The table below shows the annual energy production from new, on-shore wind resources and the associated annual transmission carrying cost to arrive at a $/MWh cost estimate for the transmission.

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115 This assumption is based on analysis performed for NESCOE in 2011, based on actual transmission revenue requirement filings with the Federal Energy Regulatory Commission, and is also consistent with other regional planning studies. RLC Engineering, *Transmission Costs for Interconnecting 3,000 MW of Windfarm Capacity in Western Maine and Coos County New Hampshire*, October 18, 2011, at 7, available at http://nescoe.com/wp-content/uploads/2015/08/SupplyCurve-Transmission_Report_18Oct2011.pdf.

	Annual Carrying Cost ($ M)	New, On-shore Wind Energy Production (MWh)	Per Unit of Energy Transmission Cost ($/MWh)
2025	$904	16,838,000	$54
2030	$904	20,872,000	$43

d) Total Cost for the Expanded RPS 35%-40% Scenario

The Expanded Scenario assumes 2,400 MW HVDC is necessary to deliver new on-shore wind resources to customers. As each hypothetical project is 1,200 MW, the transmission cost estimate for the Expanded Scenario does not include Project C. Otherwise, the high-level cost estimation and underlying assumptions are the same. The table below shows the total cost of the transmission lines and converter stations for the Expanded Scenario.

	Length	Transmission Line ($ M)	Converter Stations ($ M)	Total Capital Costs ($ M)
Project A	260	$1,450	$600	$2,050
Project B	230	$1,150	$600	$1,750
			Grand Total	**$3,800**

The total, upfront capital cost of all three hypothetical projects is approximately $3.8 Billion. Applying the 16% annual carrying cost assumption to the total capital cost estimate of $3.8 Billion results in a $608 Million annual cost. The table below shows the annual energy production from new, on-shore wind resources and the associated annual transmission carrying cost to arrive at a $/MWh cost estimate for the transmission.

	Annual Carrying Cost ($ M)	New, On-shore Wind Energy Production (MWh)	Per Unit of Energy Transmission Cost ($/MWh)
2025	$608	12,388,000	$49
2030	$608	14,623,000	$42

Appendix B: Base Case – Methodology, Assumptions, and Results

NESCOE
New England States Committee on Electricity

Renewable and Clean Energy Scenarios and Mechanisms 2.0 Study
Base Case Results

November 17, 2016

The New England States Committee on Electricity (NESCOE) retained London Economics International (LEI) to conduct modeling in connection with NESCOE's Renewable and Clean Energy Scenarios and Mechanisms 2.0 Study (Study). The Study's "Base Case" results are attached. The Base Case is one element of LEI's modeling that will be included in a larger report currently under development.

The Base Case represents the status quo. The Study will include similar analysis that looks at a range of hypothetical or "what if?" scenarios, and a *directional* comparison of those futures against the status quo. The Base Case and the hypothetical scenarios are informed by assumptions, many or all of which history may prove wrong. For example, due to its timing, the Base Case does not include clean energy resources recently selected for contract negotiation in the New England Three-State Clean Energy Request for Proposals or the Connecticut section 1(B) procurement.[1] The Base Case is also based on "snapshot in time" assumptions regarding proposed natural gas pipeline projects without the ability to predict their path to operation. The Study is not predictive or precise and should not be interpreted as such.

This brief memo summarizes and provides important caveats about the Base Case results. This includes information on the Base Case: 1) forecasted costs (energy, capacity, wholesale load), 2) resource mix and market dynamics (existing resources and new resources), and 3) state policy requirements (carbon emissions and renewable resources).

***Summary*:** Under Base Case assumptions, the total costs to wholesale load in the years 2025 and 2030 remain within a recent historical range, but increasingly reflect rising capacity costs. The resource mix is similar to the current generation fleet: remaining coal retires and new entry is mostly natural gas, wind, and solar photovoltaic (PV). Under Base Case assumptions, the region exceeds power sector carbon dioxide emissions targets and renewable resource additions are inadequate to achieve current Renewable Portfolio Standard (RPS) targets.

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[1] For more information, *see* https://cleanenergyrfp.com/2016/10/25/bidders-selected-for-contract-negotiation/ and http://www.dpuc.state.ct.us/DEEPEnergy.nsf/c6c6d525f7cdd1168525797d0047c5bf/99f2c66070f3b7a285258059006f06ff/$FILE/2016.10.27_FINAL Small Scale Selection Notice.pdf.

Forecasted Costs:

- *Energy:* Forecasted energy market prices are closely related to assumed natural gas prices. This is due to the continued dominance of natural gas-fired generation in the regional fleet in 2025 and 2030. On a seasonal basis, winter natural gas prices affect energy prices more than the summer peak demand for electricity. **In the Base Case, forecasted annual average energy prices in 2025 and 2030 are in the $48-51/MWh range, compared to 2015 actual annual average energy prices of $45/MWh**.[2] For reference, assumed natural gas prices, on an annual average basis, are $5.60/mmBTU in 2025 and $6.31/mmBTU in 2030, compared to 2015 actual annual average natural gas prices of $6.10/mmBTU.[3]

- *Capacity:* In the short term, capacity market prices are likely to be set by existing resources. **By 2025, capacity prices are forecasted to converge on the assumed net cost of new entry, and rise to the $11.50-13/kW-month range**. For comparison, the most recent capacity auction for 2019-2020 cleared at $7.03/kw-month.[4]

- *Wholesale Load Costs:* The **estimated cost to wholesale load**, calculated as the sum of modeled energy and capacity market costs, **in 2025 is $10.8 billion** (energy $6.0b plus capacity $4.8b) and **in 2030 is $ 11.9 billion** (energy $6.3b plus capacity $5.6b). For reference, actual wholesale market costs in the years 2008 to 2015 have ranged from $6.4 billion to $14.0 billion.[5] In the Base Case, the ratio of energy to capacity costs in 2025 and 2030 is approximately 55% to 45%. In 2015, the actual ratio of energy to capacity costs is 84% to 16%.[6]

Resource Mix and Market Dynamics

- *Existing Resources:* Capacity revenues represent the majority of profits for natural gas- and oil-fired generators. In contrast, energy revenues represent the majority of profits for nuclear and renewable resources. By 2025, all of the existing coal-fired generation is forecasted to economically retire. **Based on LEI's estimates of net going forward fixed**

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2 *See* 2015 Report of the Consumer Liaison Group ("2015 CLG Report"), at Table 3 on page 34, available at http://www.iso-ne.com/static-assets/documents/2016/03/2015_report_of_the_consumer_liaison_group_new_template_final.pdf.

3 *See* U.S. Energy Information Administration, natural gas city gate prices, available at http://www.eia.gov/dnav/ng/hist/n3050ma3M.htm. Assumed natural gas prices are the result of LEI's Levelized Cost of Pipeline model. For reference, the 2016 NEPOOL Economic Study assumed natural gas prices are consistent with the U.S. Energy Information Administration's 2016 Annual Energy Outlook, which are $5.40/mmBTU in 2025 and $5.57/mmBTU in 2030.

4 *See* ISO New England Key Grid and Market Stats, available at http://www.iso-ne.com/about/key-stats/markets#fcaresults.

5 2015 CLG Report.

6 In 2015, actual energy and capacity costs were $5.9 billion and $1.1 billion, respectively. 2015 CLG Report.

costs and other assumptions, existing nuclear resources remain economically viable through the study period.

Importantly, the modeling is based on assumptions identified, not on facts or resource owners' business judgment. In this study, nuclear resources' forecasted economic viability is likely influenced by several factors: (1) assumed natural gas prices, (2) LEI's approach for estimating so-called "missing money" (i.e., forecasted revenues from the wholesale markets minus estimated going forward fixed cost estimates) and (3) limitations of the approach taken to model the energy market. Assumed natural gas prices are relatively moderate on an annual average basis, \$5.60-\$6.31/mmBTU, despite seasonal price volatility ranging from \$3.48 to \$12.16/mmBTU in 2025, for example. LEI applies principles of economic theory in developing its resource type-specific net going forward fixed cost estimates, which do not include so-called "avoidable costs." LEI's modeling output showing continued nuclear economic viability does not include several financial considerations: return on equity; FCM performance risk; or potential significant capital expenditures. LEI's energy market model is not configured to simulate negative energy prices in New England.

- *New Resources:* **New resources are a mix of modeled natural gas (62%) and assumed renewables (38%)**.[7] The assumed resources are 168 MW solar photovoltaic (PV) resources and 925 MW of on-shore nameplate wind resources. These assumed resources are added by 2025. Transmission system limitations inhibit further on-shore wind development in 2025 and 2030. Over the study period, the capacity market model adds 2,000 MW of natural gas-fired resources to maintain resource adequacy.

State Policy Objectives

- *Carbon Emissions:* Power sector **carbon dioxide emissions are forecasted to be 26.8 million tons in 2025 and 25.2 million tons in 2030**.[8] For reference, 2015 actual power sector carbon dioxide emissions were 30.8 million tons. Compared to the 2020 Regional Greenhouse Gas Initiative (RGGI) aggregate carbon dioxide cap for the six New England states at 26.4 million tons, **the Base Case indicates that some in-region resources may need to procure additional RGGI allowances or carbon offsets for compliance**.[9]

7 Capacity addition percentages are based on nameplate MW.

8 Emissions results are expressed in short tons. Declining aggregate emissions in the Base Case are a function of: the declining ISO-NE long-term load forecast for energy (net of energy efficiency and solar PV), improving fuel efficiency of the generation fleet (new entry lowers system average heat rate),

9 The emissions results presented below include a small contribution from resources that are not subject to RGGI. For example, resources < 25 MW are not currently subject to RGGI. Estimating the carbon dioxide emission contributions of these resources is beyond the scope of the Study. ISO-NE economic analysis for NEPOOL suggests that an additional 2 to 5 million tons per year may be emitted by the class of resources not subject to RGGI.

- *Renewable Resources:* **Due to transmission system limitations,[10] comparative resource economics,[11] and without an increase in renewable energy imports,[12] the region is forecast to be under-supplied with Renewable Energy Certificates** (REC) relative to Renewable Portfolio Standard (RPS) targets in:
  - 2025 by 2.1 TWh, or 10.5% of Class 1 targets
  - 2030 by 3.9 TWh, or 17.0% of Class 1 targets[13]

Result Caveats and Interpretation Notes

Forecasted Costs:

- The modeling results are based on a host of assumptions. These assumptions influence which resources are dispatched, when and for how long, and, importantly, the prices at which resources produce energy and supply capacity. With time and hindsight, almost all of the assumptions may be proven wrong and may affect the models' forecasts in either direction to varying degrees.

- The energy and capacity market models are a simplified representation of the wholesale electricity markets and regional transmission system. The forward looking modeling was completed on the basis of certain assumptions which may not capture all possible operational conditions in the real world. In the model, generator availability is consistent with annual averages, the weather is always normal, and the load forecast is invariably accurate. Such a simplified representation of these markets may understate prices and emissions.[14]

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10 In the Base Case, transmission system enhancements are limited to the reliability-related upgrades that are currently in-process. LEI added on-shore wind resources to the model's northern Maine zone until the installed capacity equaled the transfer limit out of the zone.

11 Based on estimated renewable resource capital costs, LEI assumes that Alternative Compliance Payments are likely more economic than AC transmission system enhancements and other scalable RPS-eligible technologies.

12 The Base Case assumes that recent levels of imported renewable energy persist through the study period. *See* National Renewable Energy Laboratory's 2015 analysis, *Quantifying the Level of Cross-State Renewable Energy Transactions*, available at http://www.nrel.gov/analysis/policy_state_local.html. An increase in imported renewable energy may help address such a forecasted shortfall of RECs, but should be considered within the context of New York's Clean Energy Standard proposal to provide incentives for existing renewable resources that currently export to New England.

13 Class 1 Targets are defined as the sum of: Connecticut, Maine, and Massachusetts Class I; New Hampshire Class 1 and 2; Rhode Island New (including recently enacted H.B. 7413); and Vermont's Distributed Generation carve-out. These totals are estimated to be 20.1 TWh in 2025 and 22.9 TWh in 2030.

14 For more information, *see* Base Case Results slide 22. LEI analysis indicates that approximately 5% of the highest priced hours may not captured in the modeling.

Resource Mix and Market Dynamics:

- Resource retirements and new entry are based on simulated capacity market outcomes, which are primarily driven by: (1) estimated net going forward fixed costs and (2) forecasted energy market revenues.[15] Net going forward fixed costs for existing resources include fixed operations and maintenance costs; debt repayment expenses; and selling, general, and administrative expenses. All other costs (return on equity, as one example) are not included in existing resources' capacity market offers. Such other costs and financial considerations will be relevant to market participants. Exclusion of certain going forward costs from the analysis may overstate an existing resource's willingness to remain in operation. This would delay new entry and its associated impacts on energy and capacity prices and power sector emissions. Under- or over-estimated energy market revenues may delay or accelerate, respectively, some resource retirements.

- The model assumes that all market participants have a similar financial risk tolerance. This may not accurately reflect the diversity of risk tolerance among various market participants. Therefore, modeling results may under- or over-state a market participant's willingness to continue operations with an under-performing resource.

Policy Objectives:

- The model does not explicitly limit power sector air emissions. The modeling incorporates a price on carbon dioxide emissions based on current RGGI allowance secondary market prices, escalated at an assumed rate of inflation that essentially keeps carbon prices flat in real dollar terms. The price on carbon dioxide emissions, on its own, does not limit the amount of power sector air emissions. Given New England's resource mix, especially the amount of natural gas-fired generation, assumed carbon prices are unlikely to affect merit order in the dispatch.[16] A higher carbon price assumption (and all other assumptions held constant), while likely to influence prices, is unlikely to affect the region's power sector air emissions totals.[17]

- LEI's renewables development outlook and perspective on transmission system limitations directly influence the supply of RECs. LEI assumes that due to transmission system limitations, and other factors, the region may be under-supplied with RECs over the study period. The Base Case assumptions about the status quo lead to this result. To the extent the Base Case assumptions regarding renewable technology costs, energy production capabilities, and penetration are wrong, the supply of RECs may be closer to RPS targets.

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15 LEI retires resources when net going forward fixed costs exceed energy and capacity market revenues for three consecutive years.

16 *See generally* Base Case Results slide 10.

17 To the degree that higher energy prices resulting from higher carbon allowance prices increased existing resources' energy market revenues, some existing resource retirements may be delayed. The impact of potential delays in resource retirements could affect regional air emissions totals in either direction, depending on the emissions profile of the retiring resource(s) and any corresponding new entry.

London Economics International LLC

New England Modeling:
Results of the Base Case

Prepared for NESCOE

Julia Frayer, Eva Wang, Ryan Hakim

2016

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Disclaimer notice

- ***London Economics International LLC ("LEI") was retained by the New England States Committee on Electricity ("NESCOE") to model the New England wholesale energy and capacity markets under six hypothetical policy scenarios that were developed by NESCOE. LEI has made the qualifications noted below with respect to the information contained in these slides and the circumstances under which these slides were prepared.***

- ***While LEI has taken all reasonable care to ensure that its analysis is complete, power markets are highly dynamic, and thus certain recent developments may or may not be included in LEI's analysis. Notably:***
  - *LEI used the latest assumptions available as inputs to the Base Case as of July 2016.*
  - *LEI's analysis is not intended to be a complete and exhaustive analysis of future market dynamics (all possible factors of importance have not necessarily been considered). The provision of an analysis by LEI does not obviate the need for interested parties to make further appropriate inquiries as to the accuracy of the information included therein, and to undertake their own analysis and due diligence.*
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  - *There can be substantial variation between assumptions and market outcomes analyzed by various consulting organizations specializing in competitive power markets and investments in such markets. Neither LEI nor its employees make any representation or warranty as to the consistency of LEI's analysis with that of other parties.*

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LEI was retained to model the New England wholesale energy and capacity markets under six hypothetical policy scenarios that were developed by NESCOE for years 2025 and 2030

- **NESCOE is analyzing various mechanisms available to states to execute public policies, as part of its ongoing regional efforts**
- **LEI was engaged to forecast market prices and dynamics under a range of hypothetical futures that contain different resource and infrastructure expansions and potential outcomes**
  - The modeling conducted by LEI is not intended to promote a target or position on behalf of LEI or NESCOE, but rather to directionally indicate how different hypothetical scenarios could impact New England's wholesale market dynamics

Scenarios Studied

Scenario	Characteristics
Base Case	"Business as Usual" conditions under current policies and regulations to continue
Expanded RPS	Evaluate the implications of additional renewable resources with and without transmission infrastructure on power sector outcomes. RPS expansion was assumed at two different hypothetical levels
Clean Energy Imports	Examines the impacts of an additional large scale inter-regional transmission project from a neighboring system that would enable hydroelectric based energy imports into New England
Clean Energy Retirements	Examines the market impacts of retiring certain clean energy-producing generators (nuclear)
Combined Renewable and Clean Energy	Studies the market implications of creating an expanded RPS in conjunction with clean energy imports

Topics

NESCOE's Base Case outlook represents a "business as usual" perspective for the future with normal system operations, average load conditions and continuation of current market rules

Key Features of the Base Case

- **Continuation of current ISO-NE market rules, including FCM convex demand curves in the long run based on NESCOE Staff's proposed CONE values**
- **Continuation of existing state policies related to RPS and carbon allowance market (RGGI). Base Case modeling was completed before outcome of MA legislation on renewable energy procurement**
- **"Just in time" economic new entry and retirements based on the projected market dynamics (no assumed infrastructure investment based on pending state initiatives)**
- **ISO-NE's baseline expectations for load growth under weather normal (50/50) conditions and net of forecasted energy efficiency and solar PV**
- **Consideration of known and "committed to market" infrastructure projects, such as Algonquin Incremental Market, Tennessee Gas Pipeline Connecticut Expansion, and Algonquin Atlantic Bridge**
- **No transmission expansion beyond ISO-NE certified projects**
  - See ISO-NE PAC material "Transmission Transfer Capabilities Update," June 10, 2016

Modeling exhibits convergence to more balanced conditions between 2025 and 2030, when prices reach levels consistent with “new entry trigger prices” for combined cycle plants

Modeling Summary (nominal $)

	2025	2030
Energy market cost, $m	**$6,011**	**$6,309**
Average demand-weighted system LMP, $/MWh	$48.01	$50.99
Average time-weighted LMP (Internal Hub), $/MWh	$46.13	$48.96
Demand (net of EE/PV), GWh	125,212	123,713
Capacity market cost, $m	**$4,825**	**$5,637**
Capacity price (calendar year), $/kW-month	$11.49	$12.87
Cleared capacity (calendar year), GW	35.008	36.508
Wholesale market cost, $m	**$10,836**	**$11,945**

	2025	2030
Production costs, $m	$3,056	$3,221
CO2 emissions, million short tons	26.832	25.197
System production-weighted capacity factor	32.72%	30.91%
Implied market heat rate, Btu/kWh	8,238	7,758
Delivered natural gas price, $/MMBtu	$5.60	$6.31

Key Highlights

- Base Case energy market prices increase modestly from **$48/MWh in 2025** to **$51/MWh in 2030** at a **cumulative annual growth rate of 1.2% (in nominal terms)**
- The **primary driver of energy prices are the delivered gas prices** as well as the supply and demand conditions, namely **new entry and retirements**
- The primary drivers of capacity prices are the projections of quantities and timing of supply and demand, and assumptions of the Gross Cost of New Entry (“CONE”)
- Modeled capacity clearing prices in FCAs #15 and #16 (2024-2026 delivery) are $12.0/kW-month and $10.7/kW-month respectively, while FCAs #20 and #21 (2029-2031 delivery) are $13.6/kW-month and $11.8/kW-month respectively. This results in a blended capacity price of approximately **$11.5/kW-month** for calendar year **2025** and **$12.9/kW-month** for calendar year **2030**

The Base Case results in a tighter supply and demand balance by 2025 as compared to current conditions, and a shortfall in local resources qualified for Class I RPS

Key Highlights Continued

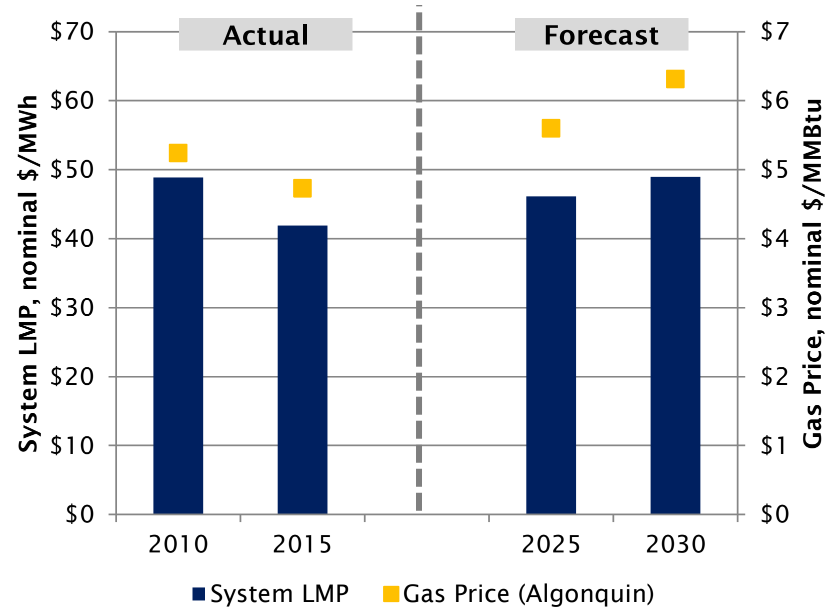
- In the short term, New England is an over-supplied system relative to NICR, with 1.4 GW clearing above the Net ICR in FCA #10 alone; therefore, the first generic combined cycle does not clear until 2025
  - LEI assumed new gas-fired resources (combined cycle) enter when projected energy and capacity prices are sufficient to meet all-in fixed costs (gross cost of new entry), which are assumed to be $13.40/kW-month in 2025 and $14.21/kW-month in 2030
  - Long-term supply and demand balance results in capacity prices clearing along the steeper portion of the demand curve, resulting in a high degree of price sensitivity from over or under-supply
- New England is expected to fall short of Class I Renewable Portfolio Standards ("RPS") targets in the Base Case by 2.1 TWh in 2025 and 3.9 TWh in 2030 (assuming no increase in imported RECs) due to internal transmission constraints that limit onshore wind development in Maine
  - Shortage of RPS targets could be addressed through Alternative Compliance Payments or through increased imports
- CO_2 emissions levels also decline as a result of falling energy demand and an increasingly fuel-efficient system (new combined cycles plants enter the market with lower heat rates)
- The production-weighted system capacity factor is 33% in 2025 and 31% in 2030. The declining system capacity factor is partially due to falling total consumption despite rising peak demand (therefore the system continually requires new generation)

Base Case energy market prices track gas price changes but also reflect increasing efficiency of the system over time

- **LMPs generally follow trends in gas prices, which increase gradually over time at a cumulative annual growth rate of 2.4% between 2025 and 2030**
  - LEI used its Levelized Cost of Pipeline Gas model to develop gas prices
  - LEI's LCOP model accounts for the market's expectation for committed expansion of natural gas pipelines as reflected in forward prices; in the longer term, Algonquin gas prices grow in line with EIA's Henry Hub price trends
- **Implied market heat rates typically fall over time as more efficient generation is added to the system**
  - 2,000 MW of CCGTs are added between 2020 and 2030 (500 MWs each in 2025, 2027, 2028, 2030)
  - 925 MW of nameplate generic on-shore wind are added between 2020 and 2030
- **Congestion is limited due to the assumption of "normal" system operations and "economically placed" new entry, resulting in similarly priced LMPs across all zones studied**
  - LMPs presented by LEI include energy and congestion components, but not loss components. Losses are not necessary for the purpose of this analysis

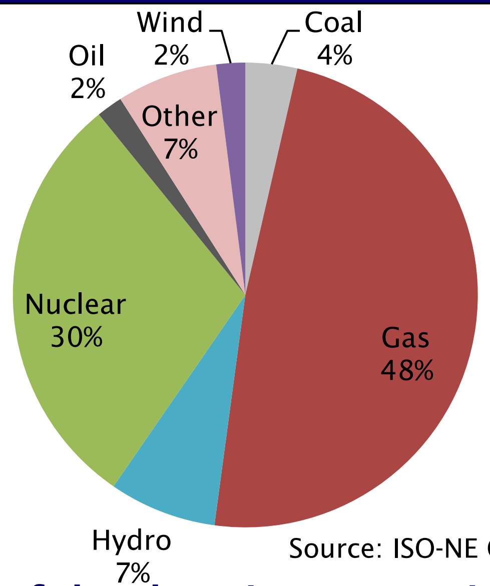
Forecast Energy Price Forecast Internal Hub (ISO-NE)

	Demand-Weighted LMP (System)	Time-Weighted LMP (Internal Hub)	Gas Price (Algonquin)	Implied Market HR
Year	$/MWh	$/MWh	$/MMBtu	Btu/kWh
2010		$48.89	$5.24	9,336
2015		$41.90	$4.73	8,856
2025	*$48.01*	*$46.13*	*$5.60*	*8,238*
2030	*$50.99*	*$48.96*	*$6.31*	*7,758*



Base Case generation mix continues to be dominated by natural gas-fired generation: operating nuclear plants remain economic while coal is retired due to modeled economics

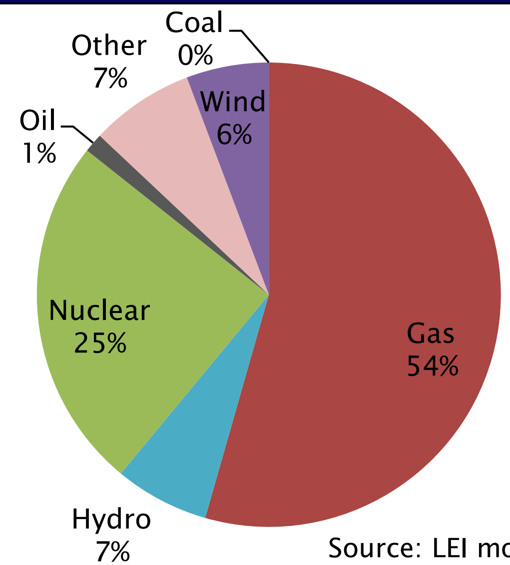
Generation Mix (MWh) – 2015



Source: ISO-NE Generation Data

Note: All figures exclude behind the meter solar PV generation. In addition, percentage differences between 2025 and 2030 are negligible when rounding to whole numbers

Generation Mix (MWh) – 2025/30

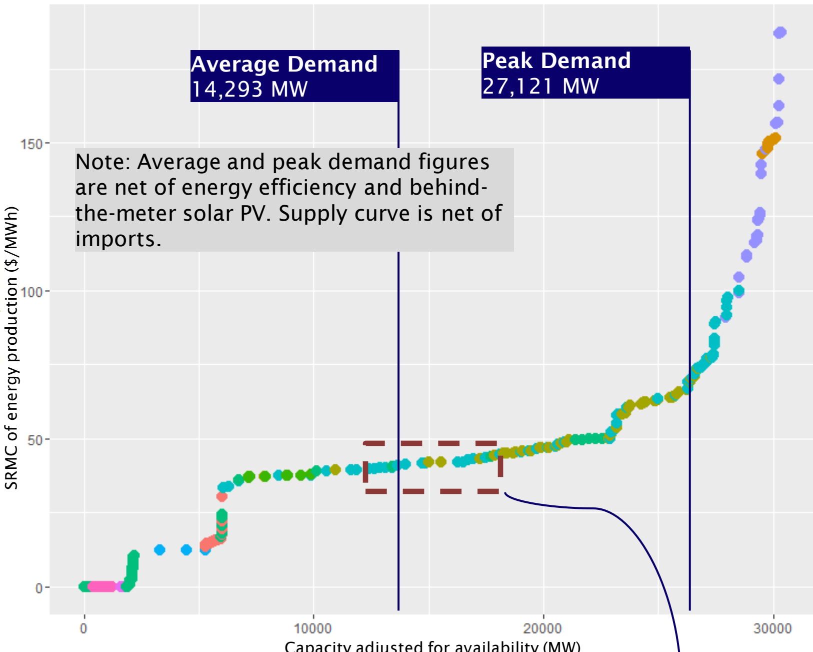


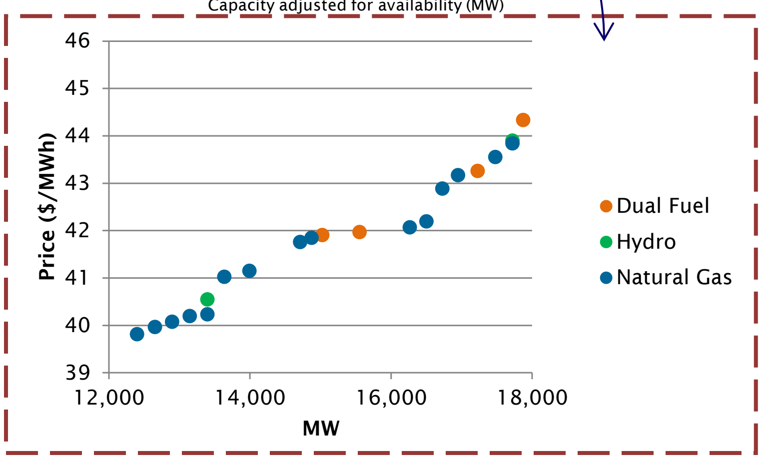
Source: LEI modeling

- **Drivers of the changing generation mix under the Base Case include supply and demand side market changes**
  - Coal is completely phased out in the Base Case before 2025 due to projected market economics (minimum going forward fixed costs exceed expected net revenues); natural gas and renewable generation replace coal generation
  - Nuclear assumed to remain economically viable because market prices cover estimated minimum going forward fixed costs on average over the modeling timeframe (but equity returns may be exhausted)
  - Onshore wind generating capacity grows from 2.2 TWh in 2015 to 6.8 TWh in 2025; however, no new wind is added beyond 2024 due to local transmission constraints, therefore the share of wind output does not grow between 2025 and 2030 in the Base Case

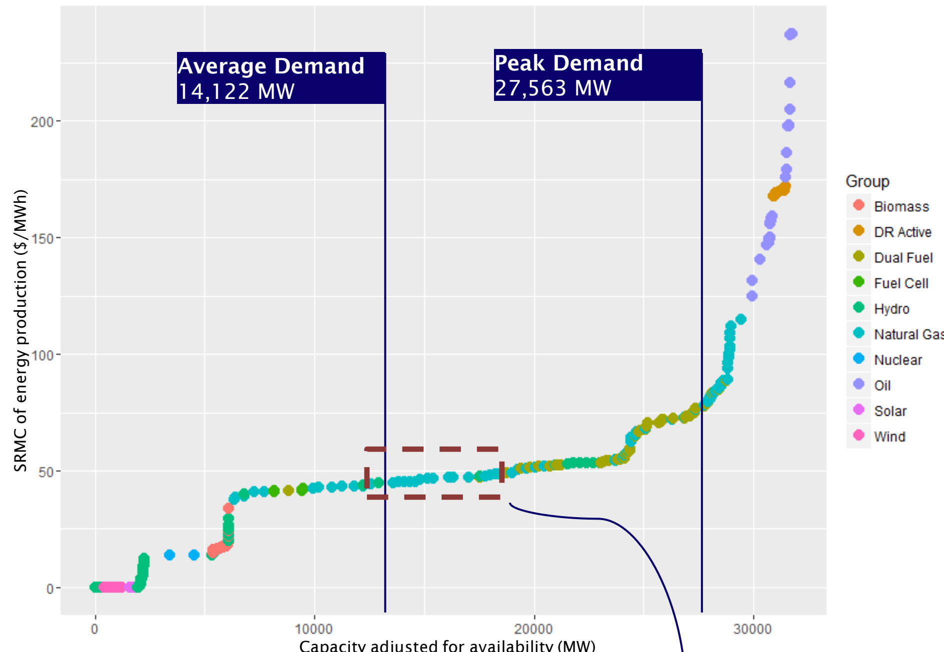
Natural gas continues to dominate the supply curve and will remain the marginal fuel source in New England for most hours

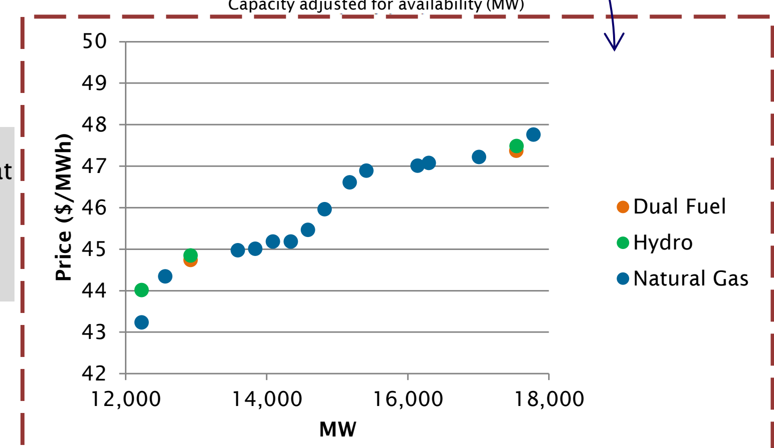
Internal Supply Curve - 2025





Internal Supply Curve - 2030

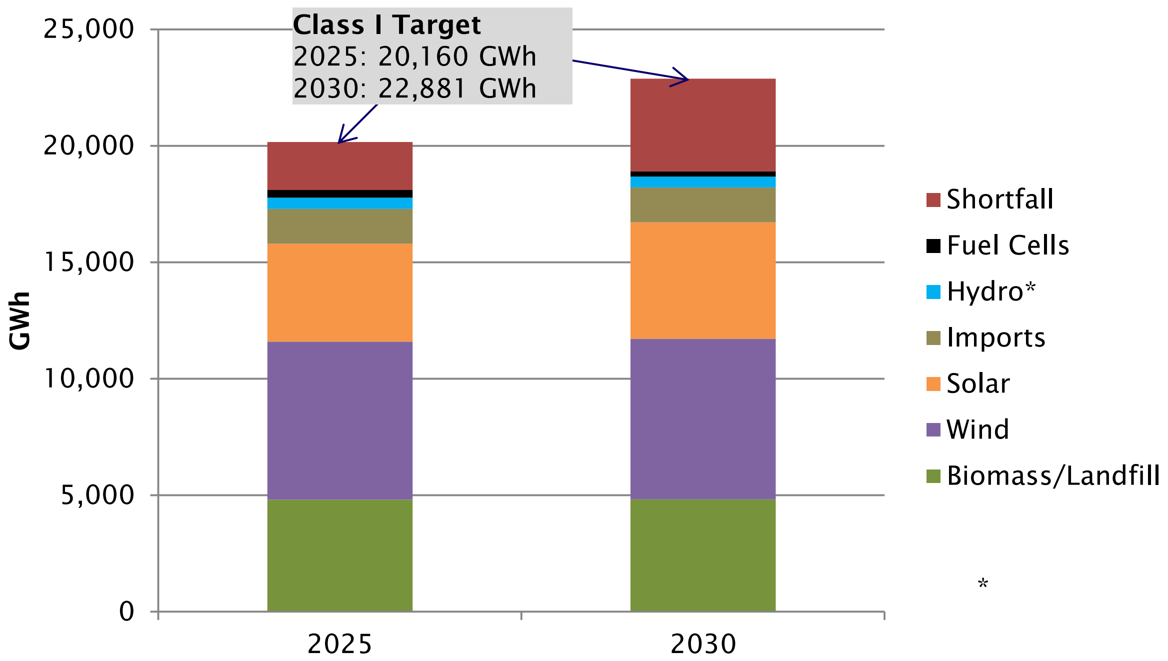




Natural gas creates the flat section of the supply curve in both 2025 and 2030

Base Case is 2.1 TWh short of Class I RPS targets by 2025 and 3.9 TWh short by 2030 (assuming no increase in imported RECs)

Modeled Supply - Class I RPS



Wind: onshore wind build out limited to 1,000 MW (including new and existing) in Bangor Hydro Electric zone

Solar: LEI has relied on ISO-NE's solar forecast (new solar also presumed to get SRECs)

*Note: Hydro output being shown constitutes only small run of river hydro production

- **The shortfall in new renewables relative to the RPS requirements does not necessarily imply large Alternative Compliance Payments ("ACP") – imported renewables may be able to reach the New England market**
  - LEI estimates that more than 500 MW and 700 MW of capacity would be available on the New Brunswick and New York interties to also help meet Class I targets (based on 2015 flows)
  - REC-qualified imports could include eligible wind, hydro, and biomass resources from New York and New Brunswick; large hydro plants are qualified to sell RECs only in Vermont and Connecticut under certain circumstances

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Capacity factors vary with the expected position in the merit order, and over time almost all existing generation will face declining capacity factors due to competition from new resources and declining electricity consumption

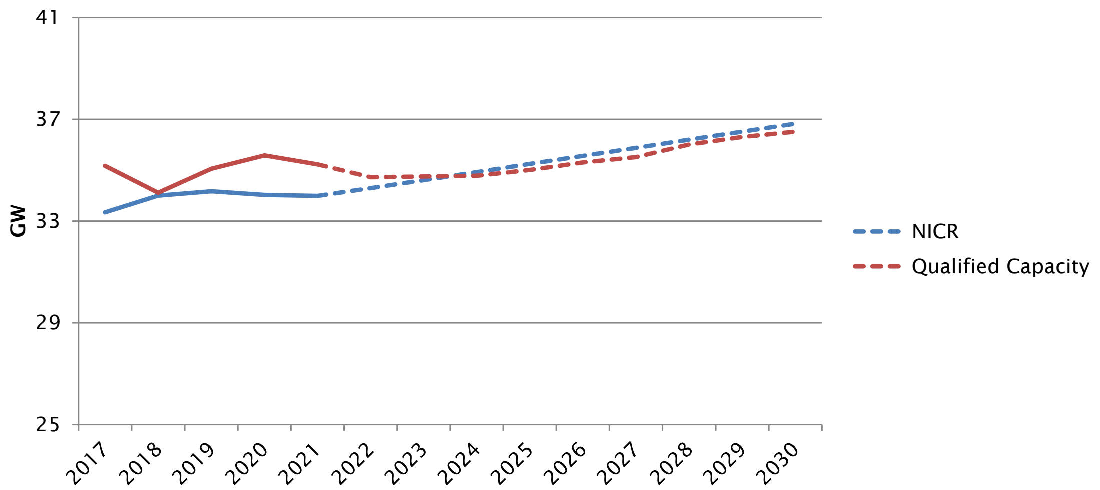
Capacity Factors by Technology

Generation Type	Capacity 2017	Capacity 2025	Capacity 2030	Capacity Factor 2025	Capacity Factor 2030	Generation 2025	Generation 2030
Existing (non-RPS eligible)	MW	MW	MW	%, Weighted avg	%, Weighted avg	GWh	GWh
Bio/Refuse	198	198	198	71%	71%	1,233	1,238
Coal Steam	920	0	0	0%	0%	0	0
Gas Combined Cycle	9,907	9,907	9,907	33%	26%	28,800	22,898
Gas Combustion Turbine	246	246	246	0%	0%	1	1
Hydro	1,502	1,502	1,502	41%	41%	5,373	5,379
Gas Steam	6	6	6	0%	0%	0	0
Gas/Oil Combined Cycle	4,185	4,185	4,185	25%	17%	9,065	6,227
Gas/Oil Combustion Turbine	649	649	649	1%	1%	85	49
Gas/Oil Internal Combustion	9	9	9	0%	0%	0	0
Nuclear Steam	4,041	3,358	3,358	91%	91%	26,708	26,756
Oil Combustion Turbine	2,133	2,133	2,133	2%	1%	296	184
Oil Internal Combustion	129	129	129	1%	0%	8	4
Oil Steam	2,219	2,219	2,219	2%	1%	299	169
Pumped Storage	1,735	1,735	1,735	10%	10%	1,518	1,515
Gas/Oil Steam	2,533	2,533	2,533	2%	1%	346	169
New Conventional - 2016 onwards							
New - Gas/Oil Combined Cycle	674	2,868	4,368	72%	68%	18,177	25,829
New - Gas Combustion Turbine	0	615	615	9%	5%	499	276
Existing Renewables							
Bio/Refuse	765	763	763	72%	72%	4,805	4,827
Gas Fuel Cell	79	79	79	48%	31%	336	218
Hydro	130	130	130	41%	41%	469	469
Solar*	588	588	588	18%	18%	926	926
Wind - On-Shore	1,021	1,021	1,021	34%	35%	3,041	3,098
New Renewables - 2016 onwards							
Solar*	102	379	504	18%	18%	597	794
Wind - Off-Shore	0	30	30	49%	50%	130	132
Wind - On-Shore	25	1,180	1,180	35%	35%	3,611	3,665

- **Capacity factors in table above represent average aggregates for “classes” of generation – some plants do better or worse than the average**
- **Low capacity factors units are potentially at risk for retirement as they are earning the least amount of profit margin from energy sales and may also be exposed if there are system events that trigger capacity performance incentive payments under ISO-NE’s Pay-for-Performance design**

New England is an oversupplied system in the near term until relative supply and demand balance is restored by FCA #15 as a result of retirements and load growth

Resource Supply and Demand Balance

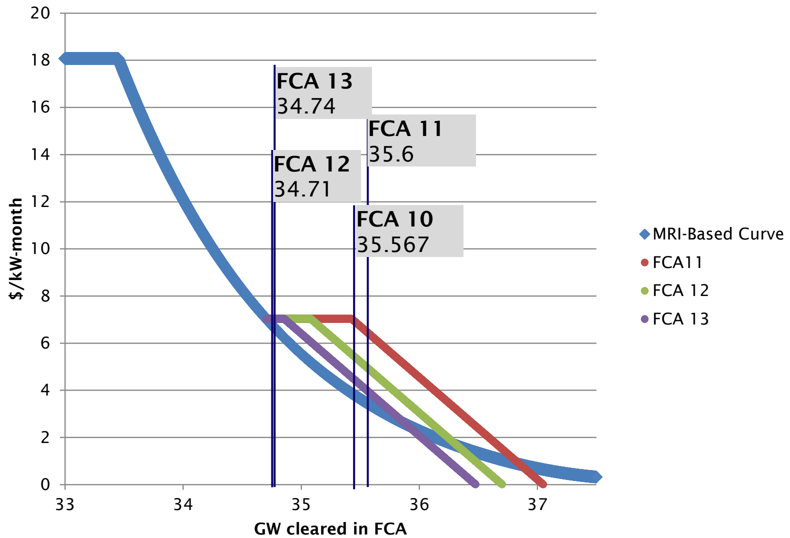


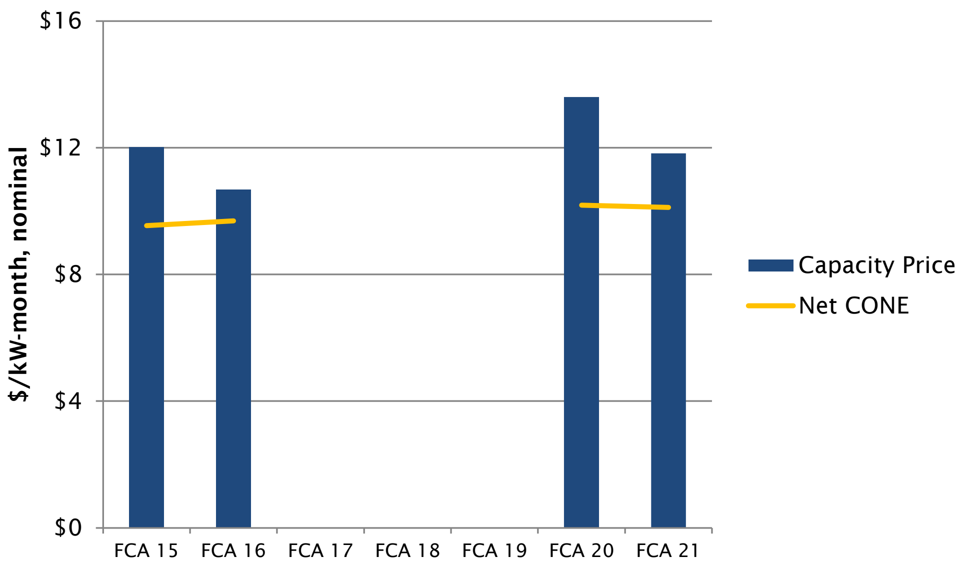
- **Net ICR ("NICR") is projected based on 14.4% reserve margin in the long run**
  - As ISO-NE's peak demand forecast declined in CELT 2016, the NICR for FCA #11 is expected to be lower than FCA #10, despite greater supply levels by 287 MW; the decline in ISO-NE's peak demand outlook is driven by increased levels of solar PV and energy efficiency

- **Capacity lost due to retirements in FCA #8 (e.g. Brayton Point) has been more than made up by new resource acquisitions in FCA #9 and #10; moreover, ISO-NE has revised down its projections for demand in its CELT 2016 (May 2016) publication**
  - New England market is expected to remain over supplied until 2024 (the first generic combined cycle plant is added in 2025)
  - LEI assumes a roughly balanced market to resume in the long run (post FCA #15)
  - If there is flatter than expected peak demand growth and/or if new resources continue to qualify in FCA #11-13, it may lead to more oversupply than modeled in the Base Case and possibly trigger more retirements

Due to economically-driven coal retirements, the transitional demand curve is a primary factor only in the next two FCAs - the convex demand curve drives outcomes by FCA #13

Modeled Capacity Prices



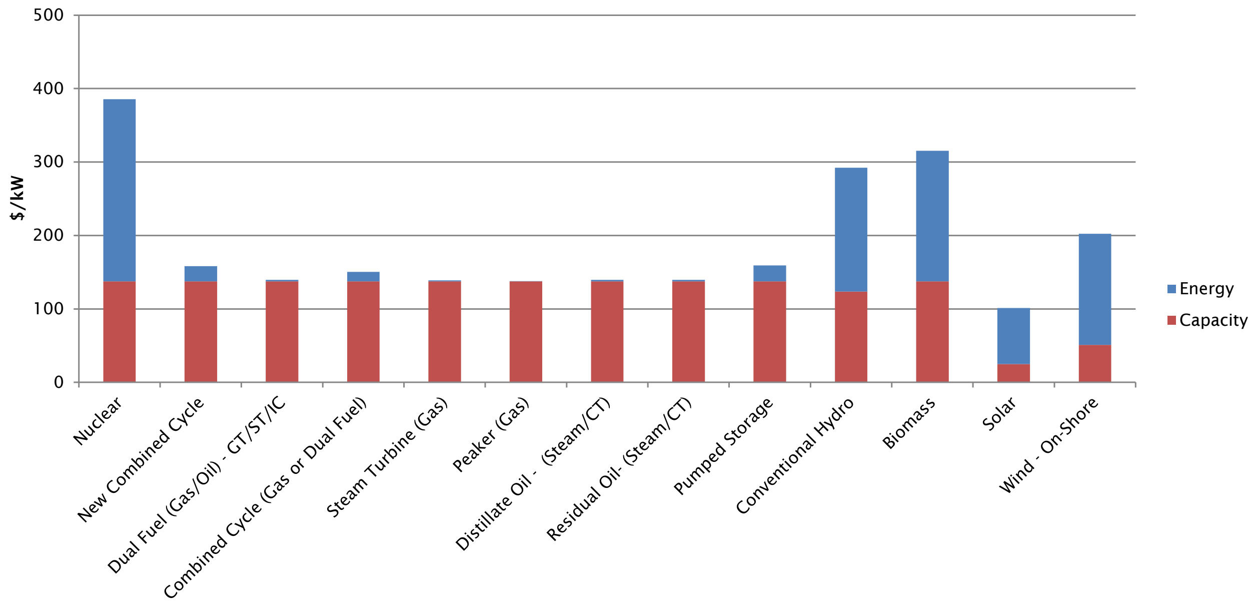


- **Suppliers' delist strategy in the FCM is assumed to be in line with competitive market forces – suppliers will "exit" the FCM when market prices fall below their minimum going forward fixed costs**
  - LEI's analysis of the minimum going forward costs finds that existing coal units will not be economically viable and are therefore retired by 2021(FCA 12)
  - No generic thermal generation is added between FCA #11 and FCA #14 due to the current state of oversupply and projected market dynamics

Over forecast timeframe, capacity revenues represent the majority of gross profits for most generators, except nuclear and renewables

Composition of 2030 gross profits are similar across technologies although slightly higher due to higher energy and capacity prices

Breakdown of Energy and Capacity gross profits, 2025



The reported values are for existing plants, with the exception of new combined cycle plants

- Energy gross profits include energy market revenues less short run marginal costs – fuel costs, variable O&M, and CO_2 emissions costs (based on "RGGI" prices)
- Renewables are assumed to only receive a fraction of the capacity market revenues due to CSO derating relative to nameplate capacity: solar (15%), onshore wind (15%), offshore wind (40%), and conventional hydro (90%)

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By definition, the Base Case is calibrated to ensure that there is no “missing money” for non-renewable resources from energy and capacity market operations

- New England’s remaining coal units are retired and therefore not included in the table on the next slide
- New combined cycle plants are roughly breaking “even” over their economic life, although some variation from year to year
- All existing wind assumed to receive some capacity revenues – but if they are energy-only, then they may have negative profits and that implies the need for REC revenues
- New wind will require approximately $34/MWh from RECs at an annual capacity factor of 37%
- Biomass profit shortfalls are equivalent to $36/MWh and $42/MWh in 2025 and 2030 respectively, which is presumed to be compensated sufficiently by RECs or other revenue streams
- The non-RPS eligible biomass resources all have positive energy market gross profits (energy revenues minus costs). The negative values are indicative of the assumed high minimum going forward costs for these biomass resources. Some of these resources may have access to other income streams. In addition, there will be plant specific differences relative to the generic fixed cost assumptions that LEI applied. Therefore plants in this category are not necessarily experiencing financial losses as suggested by the numbers.
- Under current assumptions, RECs alone will not be sufficient to recover invested capital for off-shore wind (as breakeven RECS exceed current ACP levels)

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To assess revenue sufficiency/shortfall, LEI deducted its estimate of minimum going forward fixed costs (or all-in fixed costs for new entrants) from energy market gross profits and capacity market revenues

Expected profits by fuel type, $/kW-yr

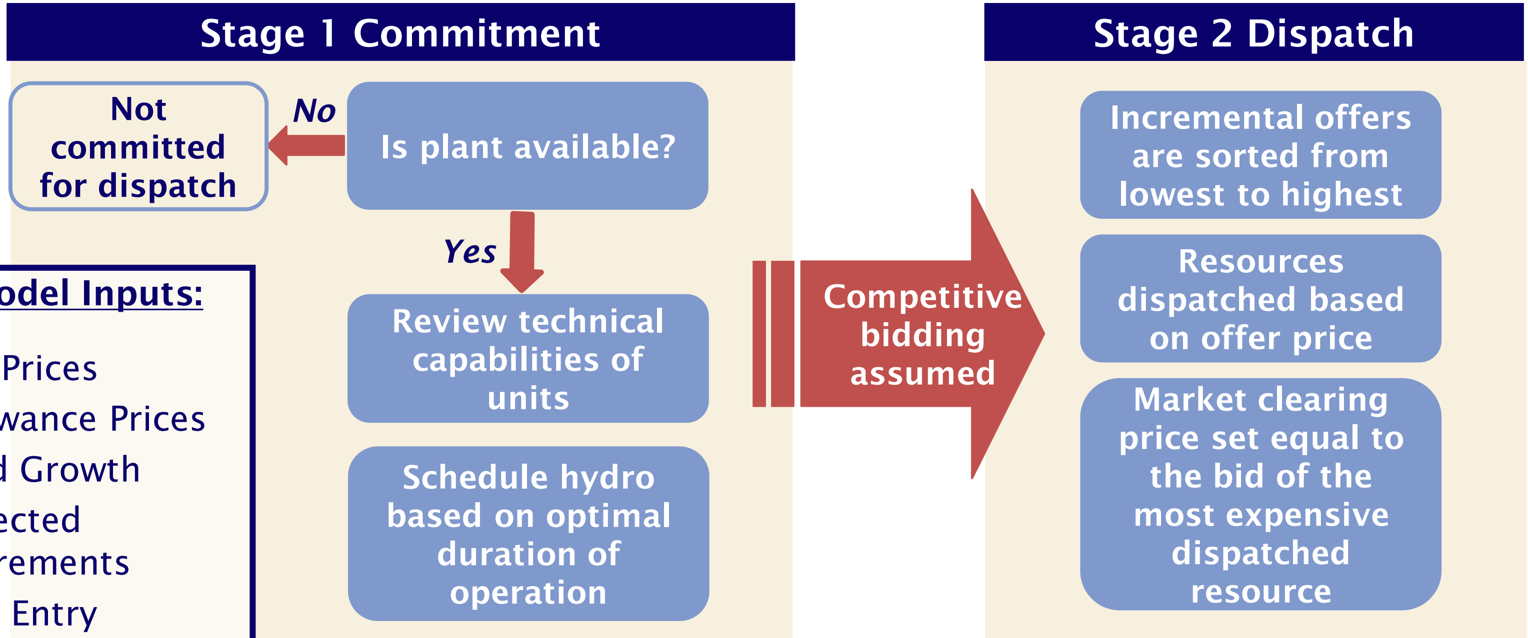
Generation Type	2025	2030
Existing (non-RPS eligible)		
Bio/Refuse	-$226	-$254
Coal Steam	-	-
Gas Combined Cycle	$75	$80
Gas Combustion Turbine	$80	$90
Hydro	$72	$75
Gas Steam	$70	$79
Gas/Oil Combined Cycle	$71	$77
Gas/Oil Combustion Turbine	$82	$91
Gas/Oil Internal Combustion	$80	$90
Nuclear	$268	$275
Oil Combustion Turbine	$90	$100
Oil Internal Combustion	$88	$99
Oil Steam	$90	$100
Pumped Storage	$118	$131
Gas/Oil Steam	$81	$91
New Conventional - 2016 onwards		
New - Gas/Oil Combined Cycle	-$3	$2
New - Gas Combustion Turbine	-$67	-$64

Generation Type	2025	2030
Existing Renewables		
Bio/Refuse	-$222	-$255
Gas Fuel Cell	-$367	-$412
Hydro	$74	$77
Solar	-$115	-$131
Wind - On-Shore	-$28	-$33
New Renewables - 2016 onwards		
Solar	-$101	-$89
Wind - Offshore	-$457	-$425
Wind - Onshore	-$110	-$106
Break-Even REC Price Needed, $/MWh		
Bio/Refuse *	$36	$42
Solar (new) **	$64	$56
Solar (existing) **	$73	$83
Wind - Onshore (new) ***	$34	$33
Wind - Onshore (existing) ***	$8	$10
Wind - Offshore (new) ****	$104	$97

"New resources" have an online date of 2016 or later
*Assuming annual average capacity factor of 70% for biomass
**Assuming annual average capacity factor of 18% for solar
***Assuming annual average capacity factor of 37% for on-shore wind
****Assuming annual average capacity factor of 54% for off-shore wind

Topics

LEI's proprietary network simulation model, POOLMod, is used to project wholesale energy prices and plant specific performance



Key Model Inputs:

- Gas Prices
- Allowance Prices
- Load Growth
- Expected Retirements
- New Entry
- Transmission

- **Modeling is long-term focused and relies on zonal analysis that reflects major future developments, such as new transmission, generation retirements/new entry, load growth**
  - POOLMod simulates the security constrained dispatch of ISO-NE
- **POOLMod has been deployed successfully by LEI in last 20 years across North American power markets and globally, under varying local rules and in many different commercial settings**
  - for evaluation of billion dollar generation projects, in support of investors in M&A due diligence, and lenders in asset financings, for assessment of merchant transmission opportunities, and as a basis for critical regulatory decisions

LEI's capacity simulator for New England's FCM is integrated with the energy market model in order to represent the relationship between energy and capacity markets

Capacity market outcomes result in new entry and retirement decisions of generators, which then affects energy market outcomes

Clearing price in capacity market set according to rules and basic supply-demand dynamics (demand curve set by the ISO-NE) and auction clearing rules

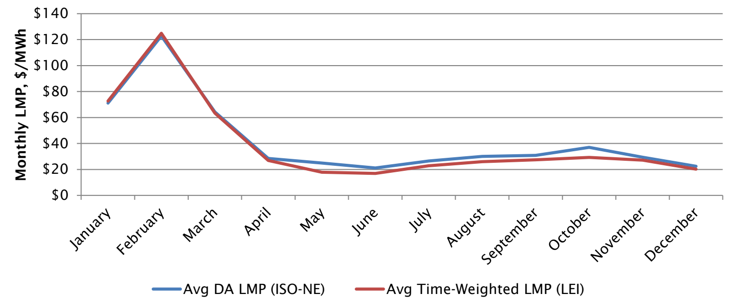
In New England's Forward Capacity Market:

- All existing capacity offers into the market at their minimum going forward costs minus their expected energy revenues from POOLMod, and new entry will commit to market only when its expected profits are sufficient to allow for commercially reasonable return (so capacity prices converge to CONE)
- Retirements take place when expected profits from all markets are insufficient to cover going forward fixed costs for three consecutive years
- New renewable entry assumed to enter to satisfy policy objectives (such as Renewable Portfolio Standards), which is reflected in the need for REC revenue streams
- Demand-side resources and imported capacity also added to capacity market dynamics as ISO rules dictate

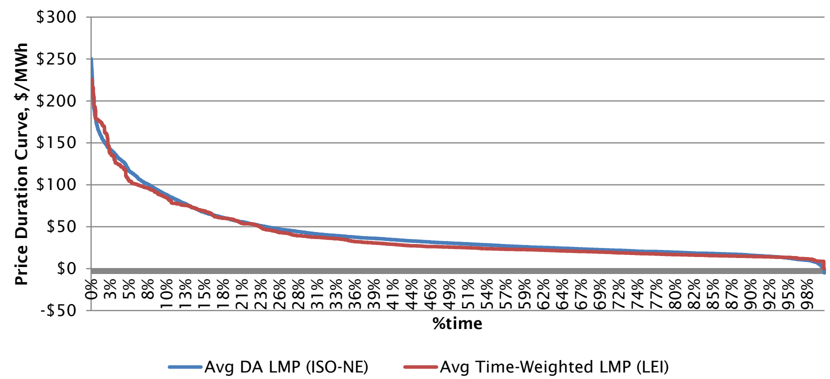
To benchmark the robustness of the model, LEI performs annual backcasts using historical inputs in order to replicate actual price levels and generation profiles

- **The backcast was done via replicating the historical actual data as closely as possible**
    - LEI used actual reported fuel prices for gas (ICE), oil (SNL Financial), coal (Ventyx), actual demand from ISO-NE, actual RGGI prices from RGGI, actual imports as reported by ISO-NE imports data, and a station database of existing plants in 2015, with seasonal capacity ratings taken directly from the 2015 CELT
- **The most recent backcast was done in spring of 2016 for the full year of 2015**
    - The actual annual DA LMP for 2015 is \$41.90/MWh for Internal Hub while POOLMod projected \$41.34/MWh on a demand-weighted basis and \$39.08/MWh on a time-weighted basis
- **LEI also compared the generation by fuel type to ensure that the backcast resulted in a reasonably close generation mix to actual generation**

Monthly LMPs, 2015, $/MWh



Price Duration Curve, 2015, $/MWh



Generation Mix

	Coal	Gas	Hydro	Nuclear	Oil	Other	Wind
Actual Generation - 2015	4%	49%	7%	30%	2%	7%	2%
LEI Backcast	3%	48%	7%	31%	1%	7%	3%

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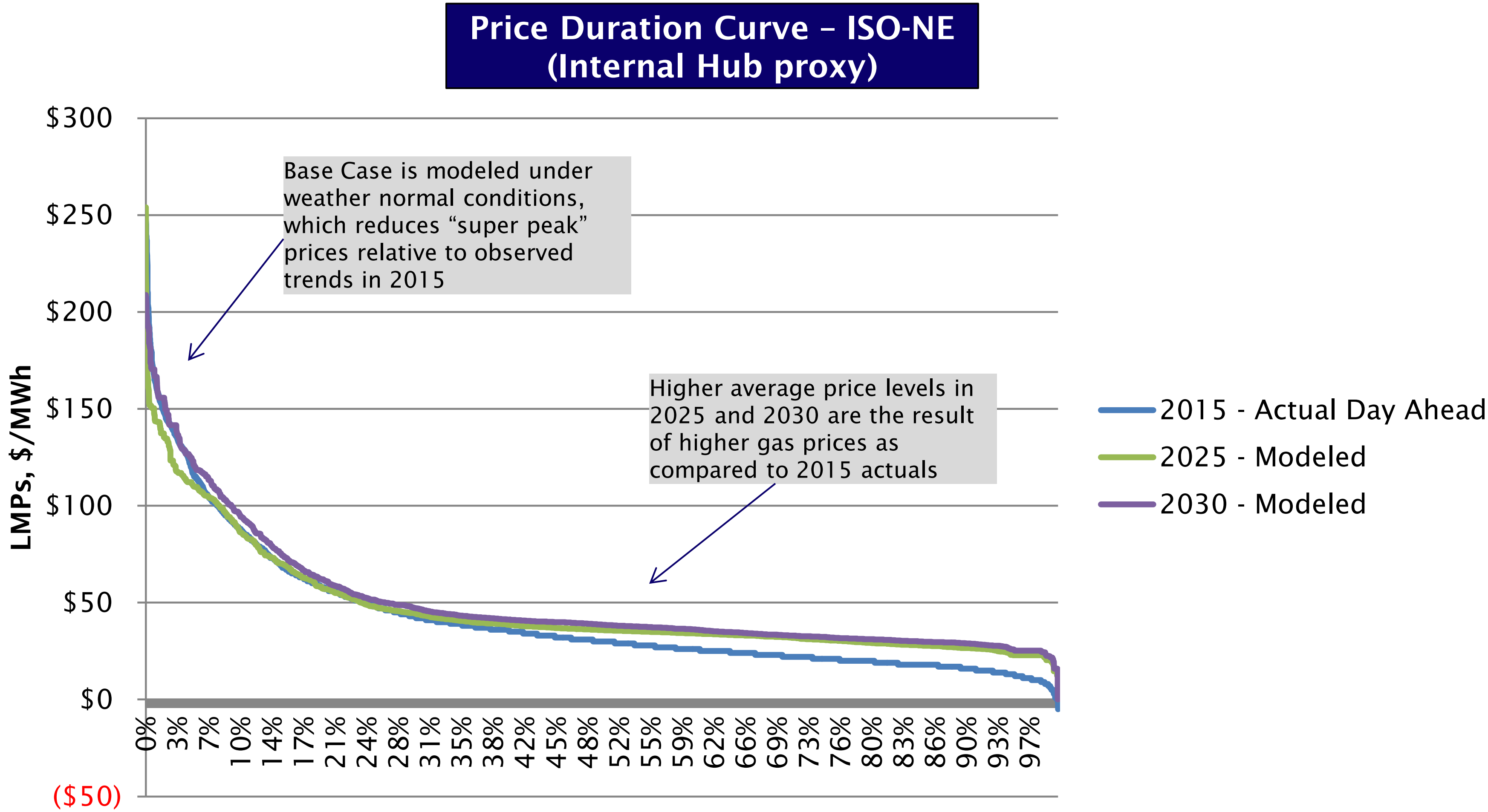
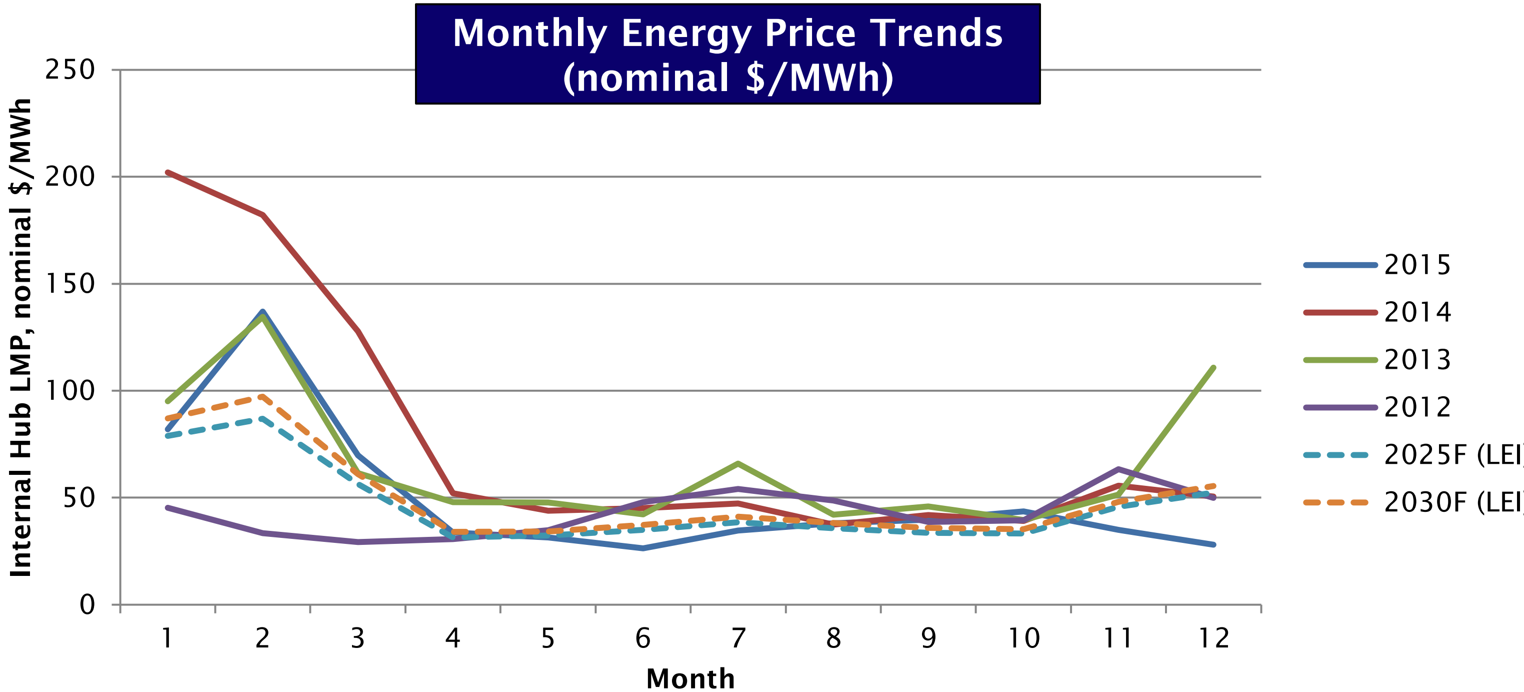
Approximately 95% of the forecasted hourly price outcomes align with the distribution of historical hourly trends



- The highest 5% of hourly prices historically are caused by stochastic drivers such as higher than expected load, extraordinary outages, or extreme weather, which will not be captured under a single Base Case modeling run

LEI's model captures seasonal variance in LMPs that match historical seasonal trends under normal conditions



- **Distribution of monthly LMPs is driven by peak load and gas price trends**
  - LEI's Levelized Cost of Gas Pipeline model produces monthly gas prices, with a clear summer and winter trend to capture commodity price volatility
  - LEI also further re-scaled these monthly prices to daily forecast levels using the 2013 daily gas price pattern. A daily price profile is important to capture intra-monthly price volatility. Daily price patterns are set such that the average of the daily gas prices in each month will equal the monthly gas price
  - Monthly LMPs generally track monthly gas price trends

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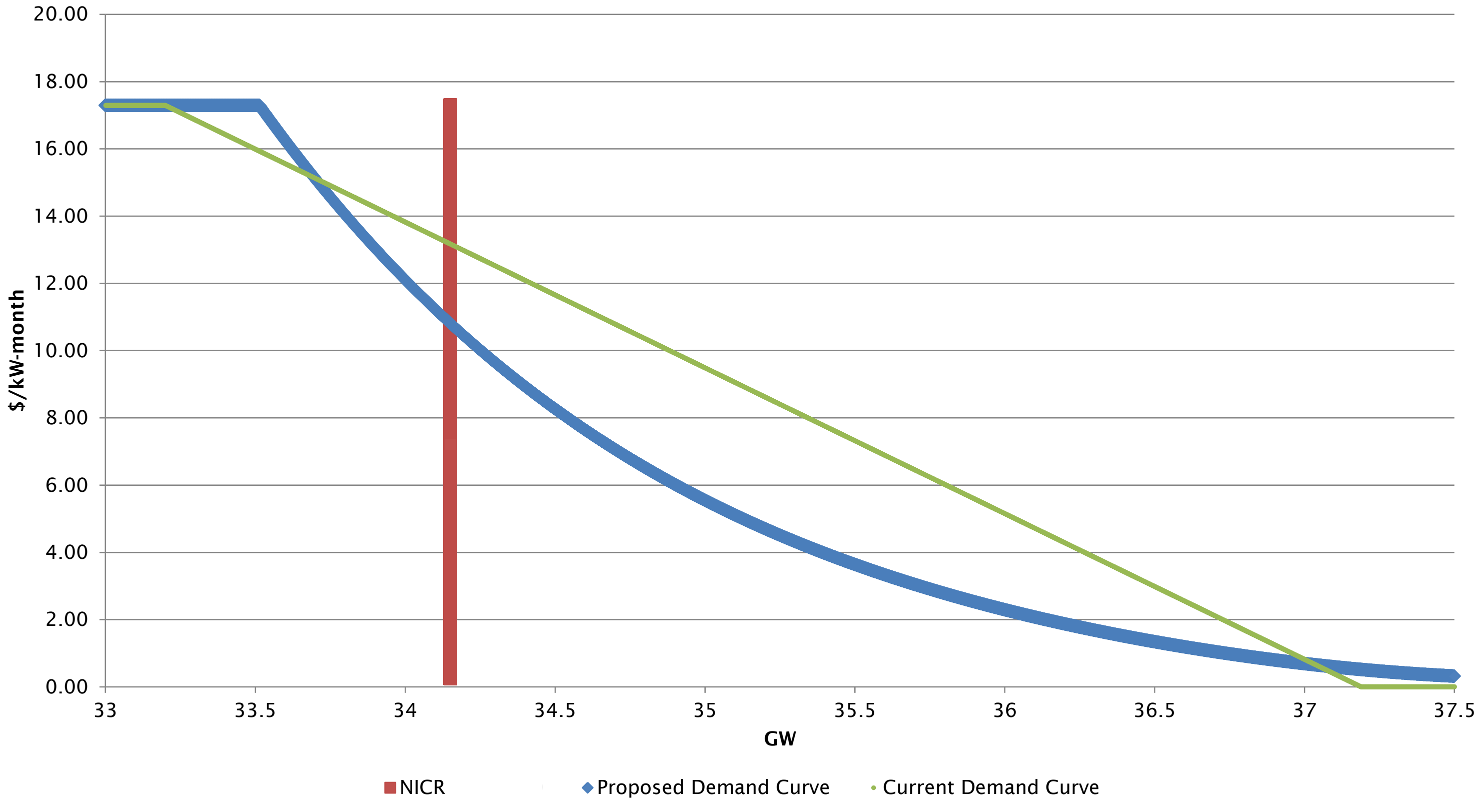
ISO-NE is changing the demand curve used in the FCA to optimize the trade-off between cost and reliability – this market rule change is reflected in the Base Case

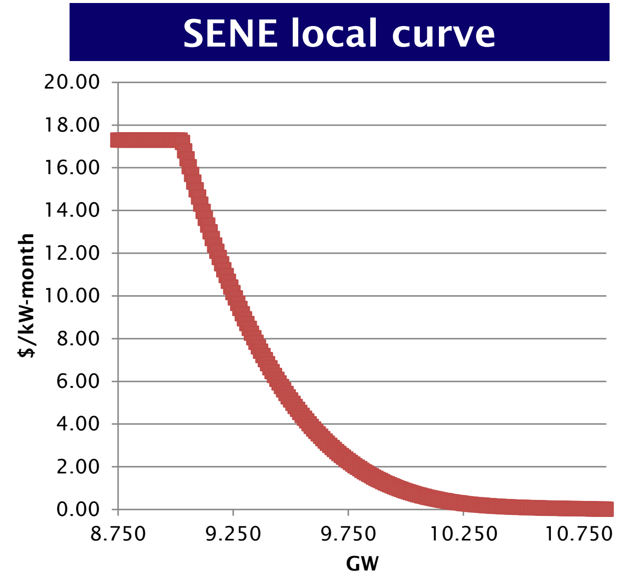
Indicative FCA Demand Curve

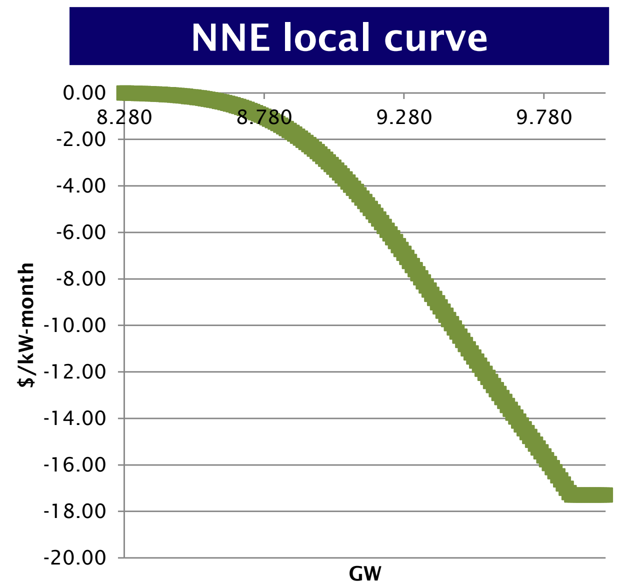


- FCA #11-13 features a transitional curve
- Post transition (FCA #14 and onward) the new set of curves (at both the system and zonal level) are convex as shown above, resulting in lower prices when there is over-supply

LEI used ISO-NE parameters to shift the demand curve as NICR grows and evaluated the potential for zonal price separation

- **The convex demand curve utilizes a polynomial function that is derived by ISO-NE's study of the Marginal Reliability Impact ("MRI")**
  - LEI used ISO-NE's coefficients in building the curve and shifts the curve to the right in order to capture NICR growth (due to ISO-NE's projected load growth)
  - The Net CONE and Scaling Factor is adjusted each year to obtain the appropriate "steepness" of the slope
- **Local curves for Southeast New England ("SENE") and Northern New England ("NNE") were also be considered**
  - The SENE curve reflects a declining price adder above the system price as more GWs clear (x-axis) and NNE reflects an increasing negative price adder as more GWs clear in the zone
  - LEI considered the potential for zonal price separation in the future and the location of new entry. However, in the almost all scenarios ran there was no price separation expected





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LEI employs an iterative capacity market decision process by simulating energy market gross revenues, and subtracting these revenues from the estimated minimum going forward costs for each resource

Calibrate timing of new entry for CCGTs

Run the energy market model (POOLMod) assuming that new CCGT enters when the capacity price is at Net CONE (after incorporating their own CSO into the market).

Run the energy model and check retirement candidates

If energy and capacity market revenues are insufficient to cover the all-in fixed costs of a new CCGT for the year that it enters, LEI will delay the CCGT investment until it at least breaks even in the first year. LEI will check for retirement candidates based off preliminary energy market revenues and capacity market revenues against the minimum going forward costs.

Recalibrate the capacity model and re-run both energy and capacity models

Once it is determined that the energy and capacity revenues are approximately sufficient to meet the all-in fixed costs for new entrants, LEI re-runs both models with the updated new entry schedule. In this instance, we re-ran this for 2025-2030 only.

Review

LEI does a final review to ensure that no further retirements are needed and that new entrants are sufficiently remunerated.

LONDON ECONOMICS

Information on fixed O&M and debt re-payment components were sourced from public information, such as company financial reports, FERC, and EIA

- **Annual fixed O&M costs were estimated using technology-specific data gathered by LEI from a number of sources**
  - Some of the data is compiled via third party commercial data provider (Velocity Suite)
  - LEI typically uses aggregated estimates by technology - except when plant detail is necessary for analysis and the reliable data is available
- **LEI also takes into account annual administrative costs, estimated at 2% of market value (these cover insurance and property taxes)**
- **For annual debt payments, LEI assumed that existing plants will carry debt on a revolving basis (even after the initial construction loans are repaid) in order to optimize returns for shareholders and provide working capital**
  - Annual debt payment is a function of market value, interest rate, financing term, and capital structure (leverage)
- **The primary factor that differentiates the debt payment by plant type is market value**
  - For market value, LEI reviewed M&A transactions for generating assets; data on recent transactions was deemed more valuable as it reflects how investors value assets under current market conditions
  - Transaction values were compiled by fuel type, technology, market location, and other differentiating factors were considered

Variations across individual plants sharing a specific technology exist and plant owners could have different proprietary numbers that drive their internal analysis

LONDON ECONOMICS

For new resources, the relevant benchmark for considering profitability are the all-in fixed cost as their invested capital is not "sunk" yet

All-In Fixed Costs and Levelized Costs of Energy for New Resources

New Resource All-in Fixed Costs, nominal $/kW-yr	2025	2030
Onshore Wind	$281	$292
Offshore Wind	$722	$714
Solar	$197	$191
Combined Cycle	$161	$171

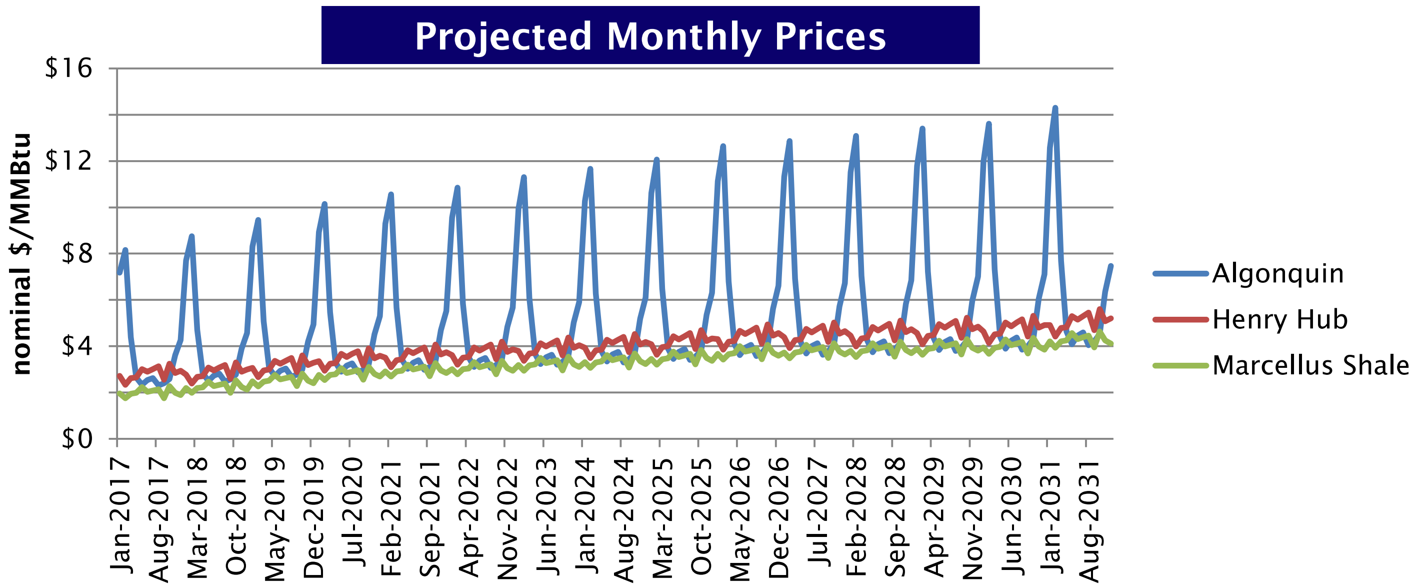
All-in fixed costs include all capital costs, fixed O&M costs, administrative costs; fuel, variable O&M, and emissions costs are not included

Levelized Cost ("LCOE"), nominal $/MWh	2025	2030
Onshore Wind	$87	$90
Offshore Wind	$153	$151
Solar	$125	$121
Combined Cycle	$64	$70

Levelized costs include all costs which are then levelized over a particular annual capacity factor (target production level)

- **Transmission costs for different resources are not included in these estimates of the all-in fixed costs. Fuel costs are also not included in the estimates of all-in fixed costs but are in the LCOE figures**
- **Key assumptions for illustrative LCOE figures:**
  - Annual capacity factors assumed for the levelized costs of energy include: onshore wind (37%), offshore wind (54%), solar (18%), and combined cycle (75%)
  - Combine cycle is assumed to have a heat rate of 6,700 Btu/kWh, variable O&M of $1.5/MWh, and the respective gas prices for 2025/2030 of $5.6 and $6.3/MMBtu

LEI's Levelized Cost of Pipeline ("LCOP") Model captures higher winter basis between delivered natural gas prices into New England and various supply hubs



- **Levelized Cost of Pipeline ("LCOP") Model looks at near-term forward markets for Algonquin Citygate and longer term price of the gas commodity (at Henry Hub and Marcellus Shale) along with the incremental costs of new pipeline capacity**
  - The LCOP Model evaluates 28 gas pricing hubs in North America, by tracking forward basis differentials and the levelized cost of building new pipeline(s) between each hub
  - Forward liquidity drops off after a few years and therefore in medium term, LEI moves to projecting gas prices based on fundamental growth rate in commodity costs (AEO 2015)
  - In the long run, the price spread between two gas pricing hubs is assumed not to exceed the levelized cost of building a new pipeline between the two hubs ($0.005/MMBtu/mile)
  - This levelized cost therefore effectively sets a long-term price cap on the transportation cost adder or basis differential between two pricing hubs
  - Monthly profile developed by looking at historical average seasonality trends

Topics

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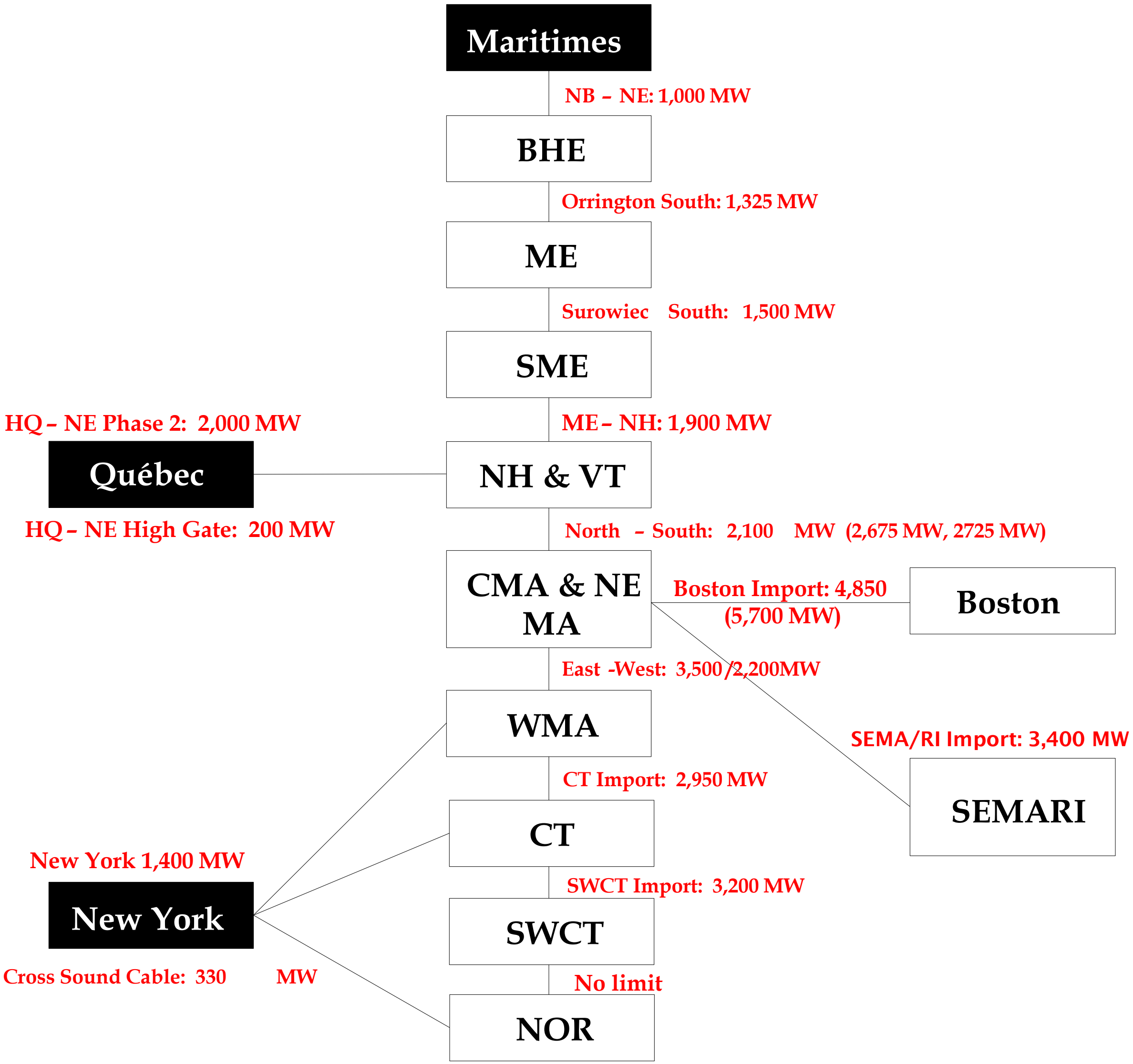
Base Case assumptions rely on the most up-to-date information, such as results from FCA #10, CELT 2016, and RSP 2015

Assumption	Approach
Network Topology	LEI divided the ISO-NE Control Area into 11 sub-zones, corresponding to oberved transmission congestion. Thermal limits were based on the ISO-NE PAC materials, "Transmission Transfer Capabilities Update, June 10, 2016" and reflected the implementation of a transmission solution in the Greater Boston Area.
Load Growth	ISO-NE's 2016 Capacity, Energy, Loads, and Transmission ("CELT") report provided the demand outlook until 2025. Beyond this, LEI extrapolated the demand for each zone using the growth rate of the three-year rolling average growth rate
Load Shape	Forecasted hourly load by ISO-NE for 2016 was used
Existing Resources	LEI used the summer and winter seasonal claimed capability published in the CELT 2016 report. Plant parameters such as fuel type, heat rate, emission rate, variable O&M, and forced outage rate were sourced from third party data providers, which aggregate data from EIA, NERC, FERC, and the EPA. Hydrology for hydro plants were developed from 10-year averages if reported. For smaller hydro plants that are not required to report, a zonal average was used
New Entry/ Retirements	Planned short term new entry was based on annoucements and included only the projects that have a high likelihood of proceeding to commercial operation (for example, resources that are cleared in the FCA, under construction, or permitted and financed). Generic renewable new entry was first added to meet RPS until 1,000 MW of wind is added in Northern Maine (due to transmission constraints). Generic gas was then added if economic, whereby projected capacity prices remunerate the Net CONE of new combined cycles
Fuel Prices	Base Case Algonquin Citygate prices were calculated using LEI's LCOP model. Residual and distillate prices were based off forwards for May 2016 for the first two years, then grown using the AEO 2015 growth rates for crude oil
Carbon Assumptions	Forwards as of May 2016 for carbon prices were used in the modeling through 2020, after which RGGI prices were escalated by 2% to keep them constant in real terms
Interchange	Imports and exports were modeled on an aggregate basis and based on inter-regional energy market dynamics benchmarked against historical patterns (2014-2015) and subject to transfer capabilities across transmission regions

ISO-NE system is modeled using a zonal approach, with key interface limits following ISO-NE's 2015 Regional System Plan and 2016 PAC materials

Modeled market topology of ISO-NE



Key interface limits (MW)

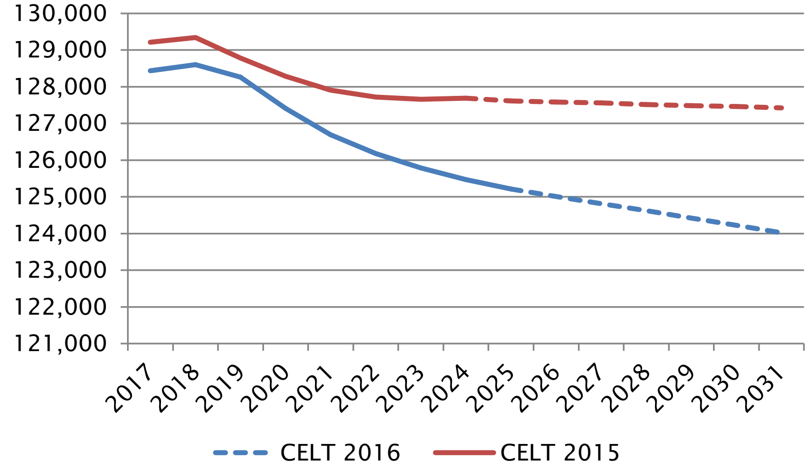
Interface	Base case
Orrington South	1,325
Surowiec South	1,500
ME-NH	1,900
North-South	2,100 2,675 (2019) 2725 (2020 and onward)
East-West	3,500
West-East	2,200
CT Import (N-1)	2,950
Boston Import (N-1)	4,850 5,700 (2019 and onward)
SEMA/RI Import	3,400
SWCT Import	3,200
Norwalk	No Limit

Source: ISO-NE PAC material "Transmission transfer capabilities update, June 10, 2016

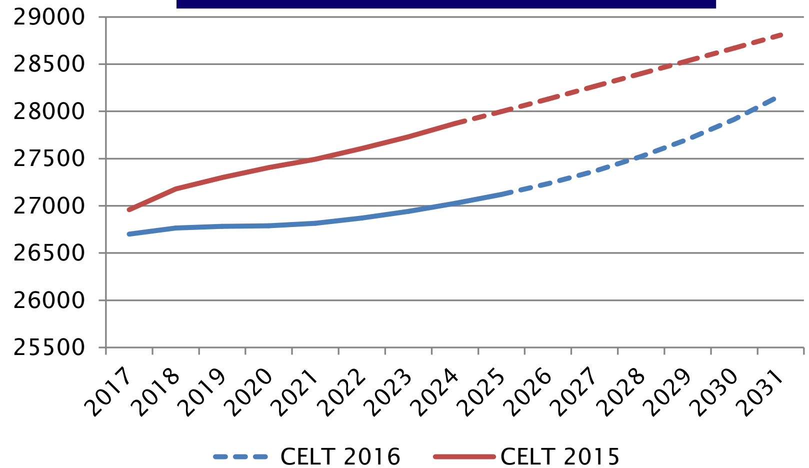
Peak demand in CELT 2016 declined by 844 MW by 2024 relative to CELT 2015 due to higher projected deployment of solar PV and passive demand response

- **The Base Case uses ISO-NE's 50/50 forecast for expected "weather normal" total demand and peak demand until 2025. Beyond that, the escalation of the previous three years growth rate is used**
  - Total demand net of solar PV and passive DR is 1.0% lower on average in CELT 2016 than CELT 2015 while peak demand is 2.1% lower during the CELT forecast period (2016 to 2025)
- **The growth of solar PV is driven mainly by policies and programs put in place by New England states, and has a significant impact of electricity demand**
  - Much of New England's distributed solar is behind the meter, and the ISO studies these trends to assess how they reduce demand
- **Passive demand response has also increased in this forecast relative to CELT 2015 by 265 MW by 2024 (system-wide)**
  - 350 MW of new passive DR cleared in FCA #10

Total Demand, GWh



Peak Demand, MW



Note: Y axis does not start from zero

New entry from within New England is predominately wind and gas, and is driven by state RPS goals and demand growth

- **The Base Case assumes that generic renewable resources are added to meet the region's various state RPS requirements**
  - The type of technology added to meet RPS is based on pragmatic consideration of what is economic and where it is economic (i.e., LEI relies on developers' indications of preferences through the interconnection queue)
  - LEI has assumed that renewable investment would occur to meet New England RPS targets, although tx limits may limit development of onshore wind resources over time
  - Solar generation is taken into account using ISO-NE's solar PV forecast
  - Cape Wind was not modeled under the Base Case because of its withdrawal from FCM; however 30 MW of Deepwater Wind (Block Island) is included as it cleared the FCA; other generic offshore wind project were not included due to economics
- **Gas-fired generating capacity is then added to meet the ICR, as needed**
  - LEI uses Net CONE as the benchmark for economic entry and assumes this will continue to be CCGT technology (based on NESCOE's input on starting Net CONE value
- **With lower peak demand and substantial new resources (from FCA #10), the first generic new CCGT is not expected until mid 2020s**
- **Projects being proposed under the Clean Energy RFP were not included in the Base Case**

Retirements include announced retirements as well as an economic assessment going forward for existing generation

- **The Base Case includes announced retirements as of June 2016**

Announced Retirements 2017 - 2019

Unit	Fuel Type	Capacity	Retirement Year
Brayton Point 1-3	Coal	1,101	2017
Brayton Point 4 & Diesels	Oil	456	2017
Pilgrim	Nuclear	683	2019
Bridgeport Harbor 3	Coal	385	2019
Bridgeport Harbor 4	Oil	22	2019
Wallingford Refuse	Biomass	2	2018
Wheelabrator Claremont 5	Biomass	3	2018

- **For other projected retirements over the modeling timeframe, LEI compared the expected minimum going forward costs against projected capacity revenues and energy market gross profits to determine retirements dynamically and on an internally consistent manner**
  - Minimum going forward fixed costs are an aggregation of fixed O&M costs and debt repayment costs, based on each generator's size, technology, and current expected market valuations and financing trends
  - If a plant is 'losing' money relative to its minimum going forward fixed costs for three consecutives years, it is retired
- **The Base Case resulted in retirement of the coal units but the continued operation of the two remaining nuclear plants in the region**

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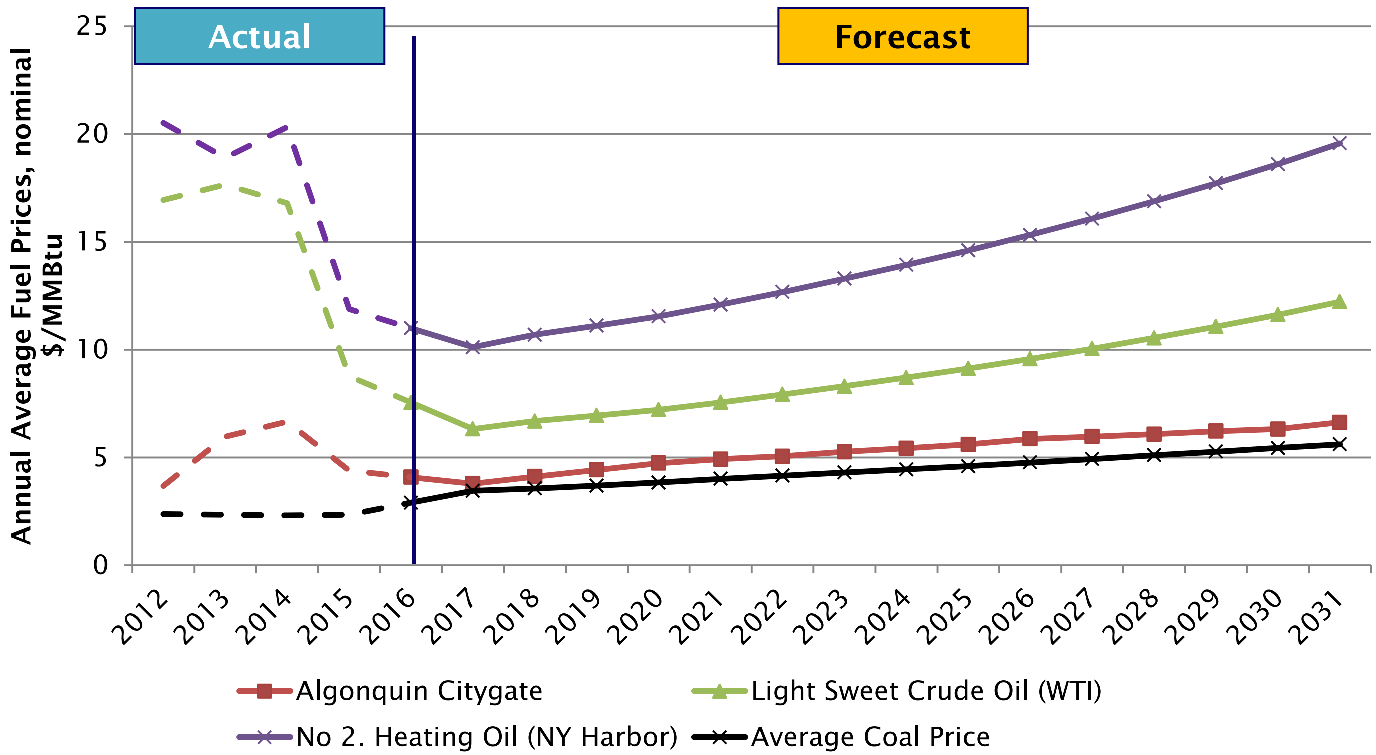
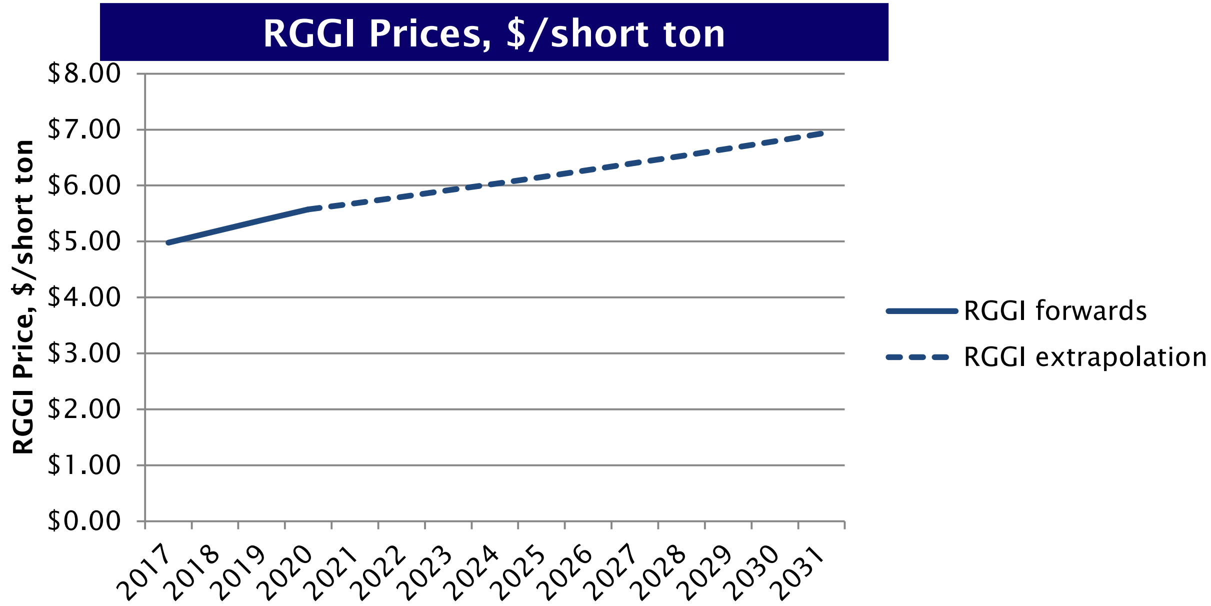
Delivered gas prices in New England start at $3.8/MMBtu in 2017 and reach $5.6/MMBtu by 2025 and $6.3/MMBtu by 2030

Modeled Fuel Prices, nominal $/MMBtu



	Historical				Forecast	
	2012	2013	2014	2015	2025	2030
Gas Prices						
Algonquin Citygate	$3.7	$6.0	$6.7	$4.4	$5.6	$6.3
Oil Prices ($/MMBtu)						
Light Sweet Crude Oill (WTI)	$16.9	$17.6	$16.8	$8.8	$9.1	$11.6
No. 2 Heating Oil (NY Harbor)	$20.5	$18.9	$20.3	$11.9	$14.6	$17.7

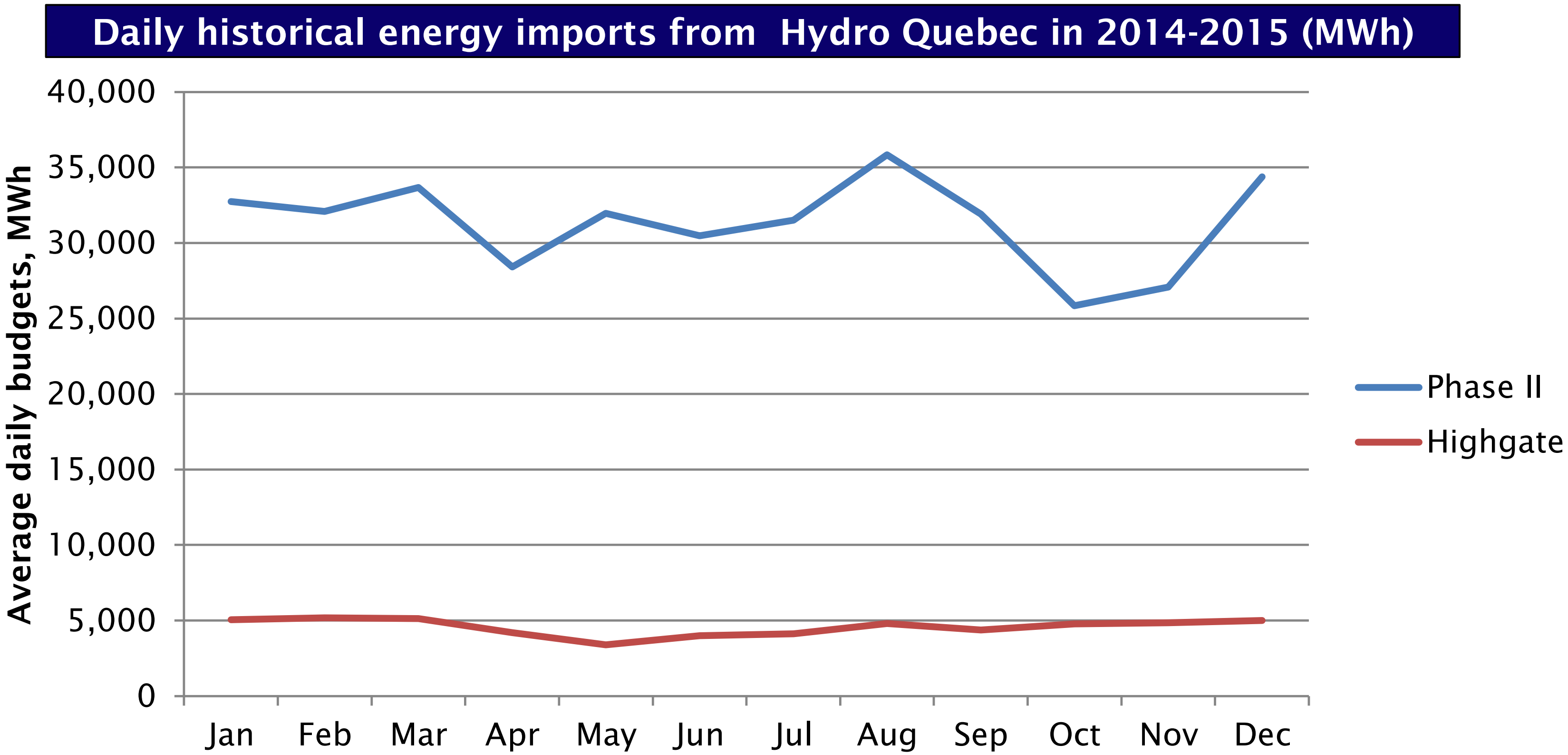
Base Case relied on current RGGI forwards until 2020 then assumed constant prices in real terms afterward



	2025	2030
RGGI Carbon Price	$6.2	$6.8

- **Currently, all states in ISO-NE participate in the Regional Greenhouse Gas Initiative (“RGGI”)**
  - RGGI requires power generation facilities with an installed capacity of over 25 MW to reduce their CO2 emissions by 50% by 2020 relative to the 2005 emissions level
  - RGGI is currently deliberating over the next few years on how to proceed post 2020. For the Base Case, LEI used forwards until 2020. Beyond 2020, LEI assumed existing rules and target will remain. RGGI carbon allowance prices grow by 2% to keep up with inflation
  - New England states are in a good position to meet CPP under existing RGGI rules

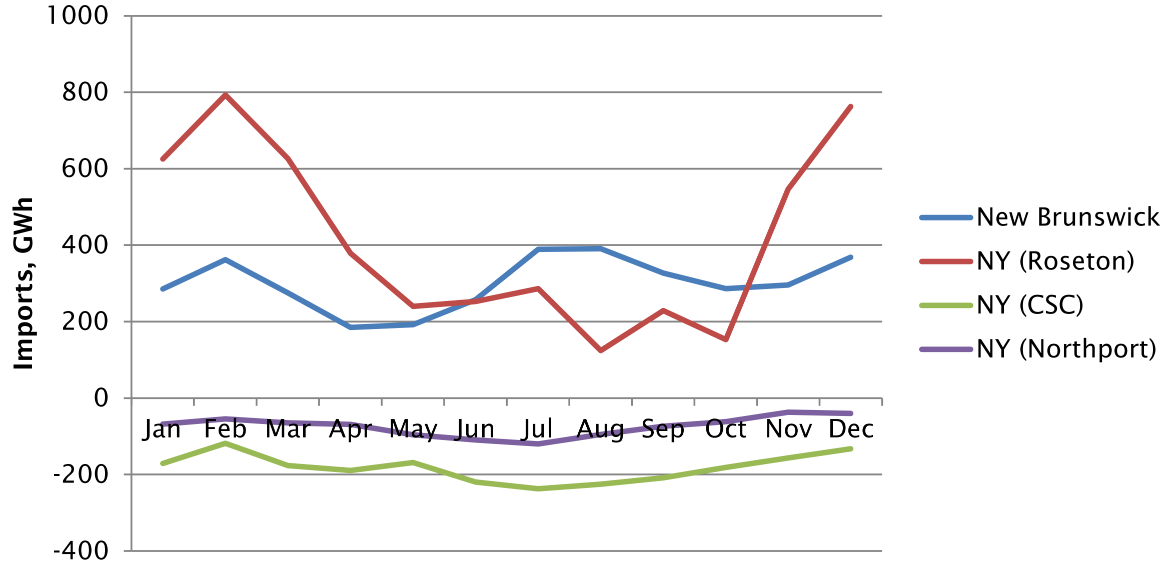
Imports from Quebec into ISO-NE are modeled to target an energy profile consistent with historical levels



- LEI models imports from Hydro Quebec based on historical trends in recent years
- The resulting average utilization rate is about 64% on Phase II (376 GWh) and 97% on Highgate (55 GWh)

Imports from NYISO and Maritimes were also modeled on the basis of historical trends

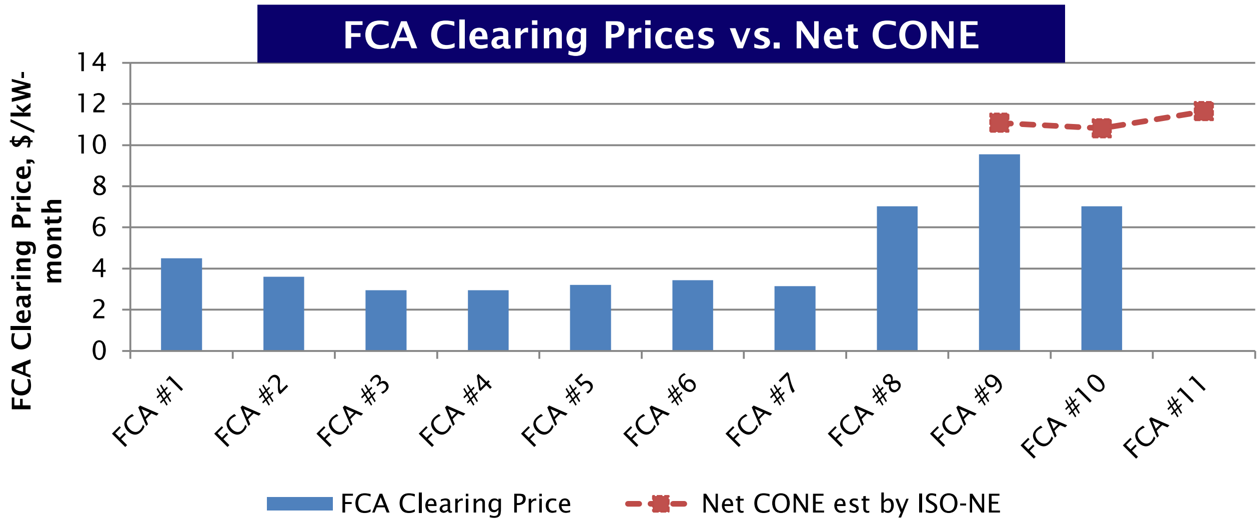
Monthly imports from NY and Maritimes in 2014-2015 (GWh)



- Imports from New Brunswick were modeled based on 2014 and 2015 levels, after Point Lepreau came back online (it was offline due to refurbishment during 2008-2012)
- Roseton interface has switched from net exporting to NYISO to net importing from NYISO since 2011, and import levels have doubled in 2013; LEI expects strong import trends to continue due to higher priced opportunities in the energy and capacity market and therefore model Roseton import based on 2014 and 2015 levels; for Northport and Cross Sound Cable, net exports to New York have been relatively stable, and are also modeled based on 2014 and 2015 average flow

Other capacity market assumptions were developed in conjunction with NESCOE and based on latest accepted (and proposed) ISO-NE market rules and on an evaluation of economic new entry

- **The Base Case assumes a Net CONE value just above the current CCGT ORTP of $9.46/kW-month starting in FCA 11**
  - Recent auctions have shown that new generation has responded to price signals in the last few FCAs
  - Additionally, recent auctions have cleared lower than Net CONE expectations
- **NET CONE for future FCAs is projected by LEI with a 2% inflation adjustment to Gross CONE and a 2% technology improvement every four years, per current market rules, to changing energy market conditions for setting the E&AS offset**
  - The Net CONE will affect the FCA starting price and the Scaling Factor in demand curve



Topics

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LEI is a global economic, financial, and strategic advisory firm specializing in energy, water, and infrastructure

About LEI

- **LEI's Analytic Approach**
  - Combines a detailed understanding of specific network and commodity industries, such as electricity generation and distribution, with sophisticated analysis
  - Uses a suite of proprietary quantitative models to produce reliable and comprehensible results
  - Advises private sector clients, market institutions, and governments on privatization, asset valuation, deregulation, tariff design, market power, and strategy in virtually all deregulated markets worldwide, particularly in Canada and the Northeast US
- **Key Practice Areas**
  - Regulatory Economics and Market Design
  - Asset Valuation and Market Analysis
  - Litigation and Expert Testimony
  - Strategy and Management Consulting
  - Renewables
  - Procurement
- **Continuous Modeling Initiative ("CMI")**
  - LEI performs multi-client forecasts for eleven regional wholesale markets across North America
  - CMIs include an examination of recent market developments, key assumptions used in the modeling, a 10-year wholesale electricity price and, where relevant, capacity price forecast

Key Facts

- **LEI entered the North American market in 1996 during the birth and development of many competitive electricity markets worldwide**

WORKING 20 YEARS 1996 2016 LONDON ECONOMICS IN NORTH AMERICA

- **LEI's subject matter experts come from over a dozen countries with degrees in economics, finance, public policy, engineering, mathematics, and business**
- **LEI Staff are located in Toronto, Boston, and Taipei, with strategic partners globally**

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LEI team has worked with many leading energy companies and key industry stakeholders around the world

In the electricity sector, LEI is active across the value chain

ASSET VALUATION, PRICE FORECASTING & MARKET ANALYSIS

- Exhaustive sector knowledge and a suite of state-of-the art proprietary quantitative modeling tools
  - Wholesale electricity market models
  - Valuation and economic appraisal
  - Due diligence support
  - Cost of capital database
  - Contract configuration matrices

REGULATORY ECONOMICS, PERFORMANCE-BASED RATEMAKING & MARKET DESIGN

- Market design, market power and strategic behavior advisory services
- Incentive ratemaking
  - Quantify current and achievable efficiency levels for regulated industries
  - Convert findings into efficiency targets mutually acceptable to utilities and regulators

EXPERT TESTIMONY & LITIGATION CONSULTING

- Reliable testimony backed by strong empirical evidence
- Expert witness service
  - Material adverse change
  - Materiality
  - Cost of capital
  - Market power
  - Tax valuations
  - Contract frustration

TRANSMISSION

- Creating detailed market simulations to identify beneficiaries and quantify costs and benefits from proposed transmission lines
  - Valuing transmission
  - Transmission tariff design
  - Procurement process and contract design

RENEWABLE ENERGY

- Renewable energy policy design, procurement, modeling, and asset valuation
  - Solar, wind, biomass, and small hydro
  - Demand response
  - Cogeneration
  - Energy efficiency
  - Micro-grids
  - Emissions credits trading
  - Energy storage technologies

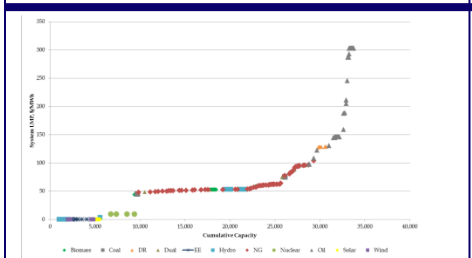
PROCUREMENT

- Designing, administering, monitoring, and evaluating competitive procurement processes
  - Auction theory and design
  - Process management
  - Document drafting and stakeholder management

Several state-of-the art modeling tools are used in the development of LEI's analysis

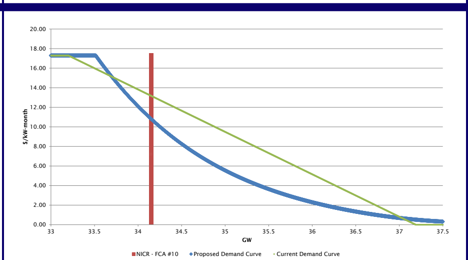
Energy Market Modeling

- LEI's proprietary dispatch simulation model is used to develop wholesale energy price forecasts
- Merit order based on marginal costs to dispatch plants, using algorithms that consider maintenance scheduling, dynamic constraints, and daily reserve margins
- Used for competitive plant valuation, emission credit market analysis, or transmission congestion analysis



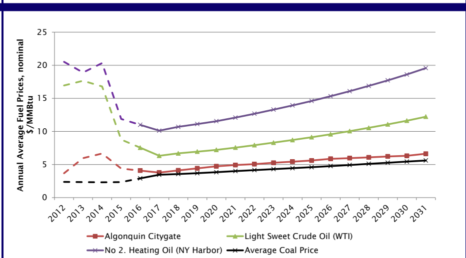
Capacity Market Modeling

- Capacity market clearing prices are set according to rules and basic supply-demand dynamics (demand curve or target reserve margin)
- Retirements take place when expected profits from are insufficient to cover going forward fixed costs
- New renewable entry assumed to satisfy policy objectives (Renewable Portfolio Standards), which is also reflected in REC revenue streams



Natural Gas Modeling

- Proprietary natural gas model based on the levelized cost of pipeline ("LCOP") is used to forecast future prices
- The LCOP approach looks at the tipping point in basis – when it is sufficiently high to cover the expected cost of new capacity
- Capable of using network models based off regional supply and demand dynamics subject to the costs of transportation and marginal supply



Macroeconomic Impact Modeling

- Widely used input-output models are utilized to measure the economic impact (ie GDP and jobs) of infrastructure investments on the economy
- Model inputs are based on LEI's energy market impact analysis, with some input on project characteristics and costs
- Deeply familiar with REMI PI+ and IMPLAN models

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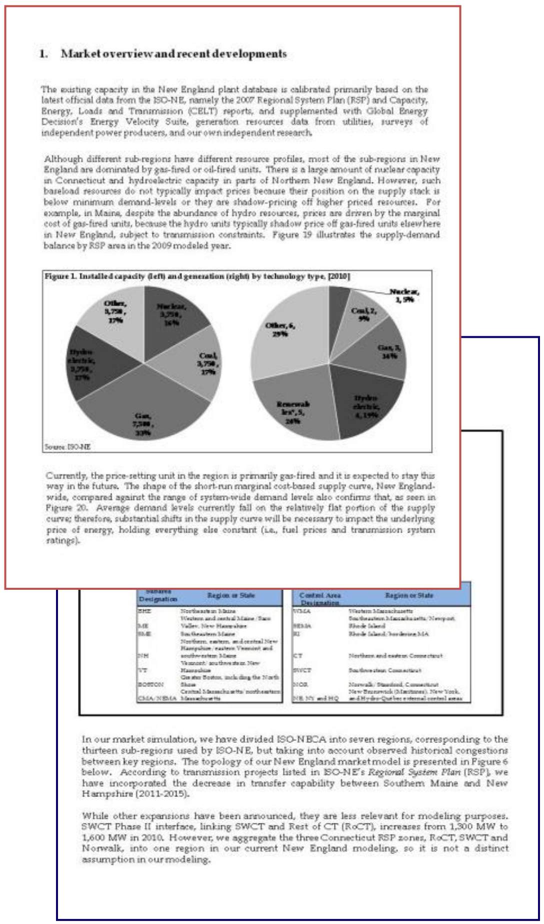
LEI publishes semi-annual price forecasts and market studies for all restructured regional power markets in North America

LEI performs multi-client forecasts for eleven regional wholesale markets across North America. The energy, and where applicable, capacity market price outlooks are updated every six months. These forecasts include an examination of recent market developments, key assumptions used in the modeling, and a 10-year wholesale electricity price and, where relevant, capacity price forecast



1. Market overview and recent developments

The existing capacity in the New England plant database is calibrated primarily based on the latest official data from the ISO-NE, namely the 2007 Regional System Plan (RSP) and Capacity, Energy, Loads and Transmission (CELT) reports, and supplemented with Global Energy Decision's Energy Velocity Suite, generation resources data from utilities, surveys of independent power producers, and our own independent research.

Although different sub-regions have different resource profiles, most of the sub-regions in New England are dominated by gas-fired or oil-fired units. There is a large amount of nuclear capacity in Connecticut and hydroelectric capacity in parts of Northern New England. However, such baseload resources do not typically impact prices because their position on the supply stack is below minimum demand-levels or they are shadow-pricing off higher priced resources. For example, in Maine, despite the abundance of hydro resources, prices are driven by the marginal cost of gas-fired units, because the hydro units typically shadow price off gas-fired units elsewhere in New England, subject to transmission constraints. Figure 19 illustrates the supply-demand balance by RSP area in the 2009 modeled year.

Figure 1. Installed capacity (left) and generation (right) by technology type, [2010]

Source: ISO-NE

Currently, the price-setting unit in the region is primarily gas-fired and it is expected to stay this way in the future. The shape of the short-run marginal cost-based supply curve, New England-wide, compared against the range of system-wide demand levels also confirms that, as seen in Figure 20. Average demand levels currently fall on the relatively flat portion of the supply curve; therefore, substantial shifts in the supply curve will be necessary to impact the underlying price of energy, holding everything else constant (i.e., fuel prices and transmission system ratings).

Subarea Designation	Region or State
BHE	Northeastern Maine
ME	Western and central Maine / Saco Valley, New Hampshire
SME	Southeastern Maine
NH	Northern, eastern, and central New Hampshire / eastern Vermont and southwestern Maine
VT	Vermont / southwestern New Hampshire
BOSTON	Greater Boston, including the North Shore
CMA/NEMA	Central Massachusetts/ northeastern Massachusetts

Control Area Designation	Region or State
WMA	Western Massachusetts
SEMA	Southeastern Massachusetts / Newport, Rhode Island
RI	Rhode Island / bordering MA
CT	Northern and eastern Connecticut
SWCT	Southwestern Connecticut
NOR	Norwalk / Stamford, Connecticut
NB, NY and HQ	New Brunswick (Maritimes), New York, and Hydro-Québec external control areas

In our market simulation, we have divided ISO-NE BCA into seven regions, corresponding to the thirteen sub-regions used by ISO-NE, but taking into account observed historical congestions between key regions. The topology of our New England market model is presented in Figure 6 below. According to transmission projects listed in ISO-NE's *Regional System Plan* (RSP), we have incorporated the decrease in transfer capability between Southern Maine and New Hampshire (2011-2015).

While other expansions have been announced, they are less relevant for modeling purposes. SWCT Phase II interface, linking SWCT and Rest of CT (RoCT), increases from 1,300 MW to 1,600 MW in 2010. However, we aggregate the three Connecticut RSP zones, RoCT, SWCT and Norwalk, into one region in our current New England modeling, so it is not a distinct assumption in our modeling.

Contents:

An overview of the market and recent developments - a discussion of the key market drivers, and developments in the previous six months, including any new entrants and retirements, new transmission lines, market rule changes, market auction outcomes, mergers and acquisitions, new state policies or initiatives, and environmental rules

Modeling assumptions in the LEI price forecast - a detailing of assumptions used for each region, including market topography, future fuel prices, emission costs, the cost of generic new entry, import and export flows, demand levels, and the breakdown of supply. For regions with multiple zones, assumptions are broken down by zone

10-year price forecast - a price forecast for wholesale electricity prices, and capacity market prices (for those regions where this is applicable). Where relevant, these price forecasts are broken down by zone

Available markets

- Alberta
- California (CAISO)
- Midwest (MISO)
- New England (ISO-NE)
- New York (NYISO)
- Pennsylvania-New Jersey-Maryland Interconnection (PJM)
- Ontario
- Southeast Reliability Council (SERC)
- Southwest Power Pool (SPP)
- Texas (ERCOT)
- Western Electric Coordinating Council (WECC)

Appendix C: Alternative Scenarios – Scenario Analysis Results

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New England Modeling:

Results of Scenario Analysis

Hypothetical Scenario Analysis Results

Prepared for NESCOE

Julia Frayer, Eva Wang, Ryan Hakim

2016

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Disclaimer notice

- ***London Economics International LLC ("LEI") was retained by the New England States Committee on Electricity ("NESCOE") to model the New England wholesale energy and capacity markets under six hypothetical policy scenarios that were developed by NESCOE. LEI has made the qualifications noted below with respect to the information contained in these slides and the circumstances under which these slides were prepared.***

- ***While LEI has taken all reasonable care to ensure that its analysis is complete, power markets are highly dynamic, and thus certain recent developments may or may not be included in LEI's analysis. Notably:***
  - *LEI used the latest assumptions available as inputs as of July 2016. However, capital cost assumptions for new renewable resources based on 2016 NREL Technology Baseline issued in September 2016.*
  - *LEI's analysis is not intended to be a complete and exhaustive analysis of future market dynamics (all possible factors of importance have not necessarily been considered). The provision of an analysis by LEI does not obviate the need for interested parties to make further appropriate inquiries as to the accuracy of the information included therein, and to undertake their own analysis and due diligence.*
  - *No results provided or opinions given in LEI's analysis should be taken as a promise or guarantee as to the occurrence of any future events.*
  - *There can be substantial variation between assumptions and market outcomes analyzed by various consulting organizations specializing in competitive power markets and investments in such markets. Neither LEI nor its employees make any representation or warranty as to the consistency of LEI's analysis with that of other parties.*

- ***The contents of LEI's analysis do not constitute investment advice. LEI, its officers, employees and affiliates make no representations or recommendations to any party. LEI expressly disclaims any liability for any loss or damage arising or suffered by any third party as a result of that party's, or any other party's, direct or indirect reliance upon LEI's analysis and this report.***

In addition to a Base Case, LEI was asked to model the New England wholesale energy and capacity markets under five hypothetical policy scenarios that were developed by NESCOE

- **LEI understands that NESCOE will be using the modeling work that LEI has completed to conduct its own analysis of Hypothetical Scenarios of Mechanisms available to states to execute public policies**
  - The Base Case results have been presented in a separate companion slide deck
- **The five hypothetical scenarios evaluated New England wholesale power market conditions under a range of futures that contain different resources and varying infrastructure expansions**
  - The modeling conducted by LEI is not intended to promote a target or position on behalf of LEI or NESCOE, but rather to directionally indicate how different hypothetical scenarios could impact New England's wholesale market dynamics

Scenarios Studied

Scenario	Characteristics
Base Case	"Business as Usual" conditions with current laws and regulations to continue
Expanded RPS (two scenarios)	Evaluate the implications of additional renewable resources with and without transmission infrastructure on power sector outcomes. RPS expansion was assumed at two different hypothetical levels
Clean Energy Imports	Examines the impacts of an additional large scale inter-regional transmission project from a neighboring system that would enable hydroelectric based energy imports into New England
Nuclear Retirements	Examines the market impacts of retiring nuclear energy resources
Combined Renewable and Clean Energy	Studies the market implications of creating an expanded RPS in conjunction with clean energy imports

The Base Case outlook represents a "business as usual" perspective for the future with normal system operations, average load conditions and continuation of current market rules and policies

Key Features of the Base Case

- Continuation of current ISO-NE market rules, including FCM convex demand curves in the long run based on NESCOE's assumed CONE values
- Continuation of existing state laws related to RPS and carbon allowance market (RGGI). Base Case modeling was completed before outcome of MA legislation on renewable energy procurement
- "Just in time" economic new entry and retirements based on the projected market dynamics (no assumed infrastructure investment based on pending state initiatives)
- ISO-NE's baseline expectations for load growth under weather normal (50/50) conditions and net of ISO-NE's forecasted energy efficiency and solar PV outlook
- LEI's delivered gas price outlook does not specify the size (throughput) of generic pipeline expansions, but does factor into the forecast known and "committed to market" pipeline infrastructure projects, such as Algonquin Incremental Market, Tennessee Gas Pipeline Connecticut Expansion, and Algonquin Atlantic Bridge
- No transmission expansion beyond ISO-NE certified projects
  - See ISO-NE PAC material "Transmission Transfer Capabilities Update," June 10, 2016

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Five scenarios with different investment profiles were designed by NESCOE to evaluate the impacts on market dynamics

New Entry and Retirements by 2030

	Scenario	Retirements	Renewable Entry	Natural Gas Entry	Transmission	Imports
	Base Case	Remaining coal	+300 MW Solar PV +925 MW Onshore Wind	+ 2,000 MW Combined Cycle	ISO-NE: June 2016 PAC Transmission Transfer Capabilities Update	Historical trends continue over existing ties
Alternative Scenarios (New Entry and Retirements are *in addition to the Base Case*)	More Aggressive RPS 40-45	+261 MW Natural Gas	+1,250 MW Solar PV +5,500 MW Onshore Wind +2,500 MW Offshore Wind	- 2,000 MW Combined Cycle (net 0 MW added)	+3,600 MW HVDC	
	Expanded RPS 35-40		+1,000 MW Solar PV +3,575 MW Onshore Wind +2,000 MW Offshore Wind	- 2,000 MW Combined Cycle (net 0 MW added)	+3,600 MW HVDC	
	Clean Energy Imports	+171 MW Natural Gas		- 1,000 MW Combined Cycle (net 1,000 MW added)	+1,000 MW HVDC	+1,000 MW CSO (7.880 TWh/year)
	Nuclear Retirements	+3,350 MW Nuclear		+ 3,500 MW Combined Cycle (net 5,500 MW added)		
	Combined Renewable and Clean Energy	+1,176 MW Natural Gas	+1,250 MW Solar PV +5,500 MW Onshore Wind +2,500 MW Offshore Wind	- 2,000 MW Combined Cycle (net 0 MW added)	+3,600 MW HVDC +1,000 MW HVDC	+1,000 MW CSO (7.880 TWh/year)

- **Two Expanded RPS scenarios were modeled at different levels of Class I wind and solar resources in 2025 and 2030:**
  - "Expanded RPS 35-40" represents 35% and 40% RPS targets in 2025 and 2030, respectively
  - "More Aggressive RPS 40-45" represents 40% and 45% RPS targets in 2025 and 2030, respectively
- **New natural gas fired resources are driven by price signals in the capacity market. In scenarios where there is more oversupply in the capacity market, new combined cycle investment would be delayed as it would not receive sufficient capacity revenues to cover its all-in fixed costs**
- **New solar, wind, and transmission additions are modeled as state law – or policy – driven investments. However, retirements are still based on economics (if expected revenues do not cover minimum going forward costs for three years)**
- **In all scenarios, coal is retired before 2025**

Three sensitivities were designed to measure the indirect impact on natural gas prices from nuclear retirements as well as implications of wind build out with transmission constraints

Sensitivities

Sensitivity	Change
Nuclear Retirements	**Base Case natural gas prices**
Nuclear Retirements Gas x 1.25	25% higher natural gas prices
Nuclear Retirements Gas x 1.5	50% higher natural gas prices
More Aggressive RPS 40-45	**+3,600 MW HVDC**
Without Transmission	No HVDC

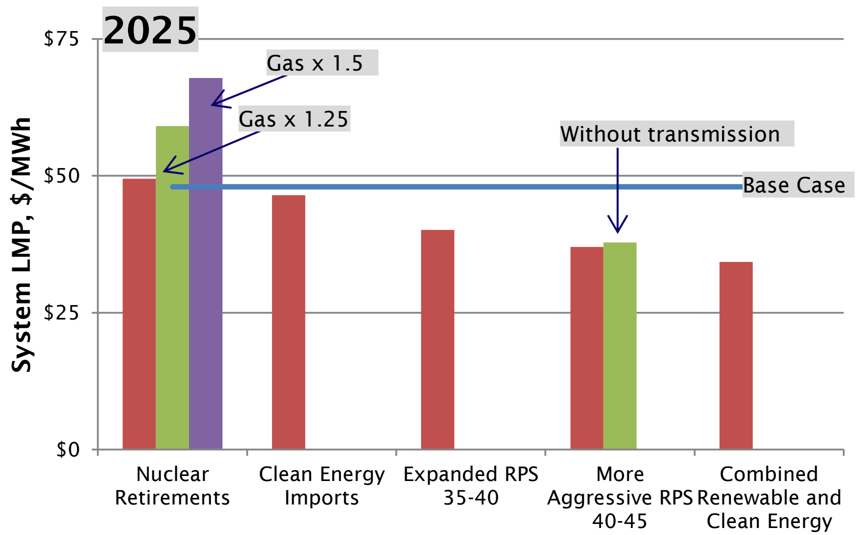
- Sensitivities on natural gas prices were modeled at 25% higher natural gas prices ("Nuclear Retirements Gas x 1.25") and 50% higher natural gas prices ("Nuclear Retirements Gas x 1.5"). Sensitivities with different gas prices were only done for the Nuclear Retirements scenario to allow for identification and measurement of the potential indirect effect on gas prices (due to increased natural gas demand on a constrained pipeline network after nuclear resources exit the market)

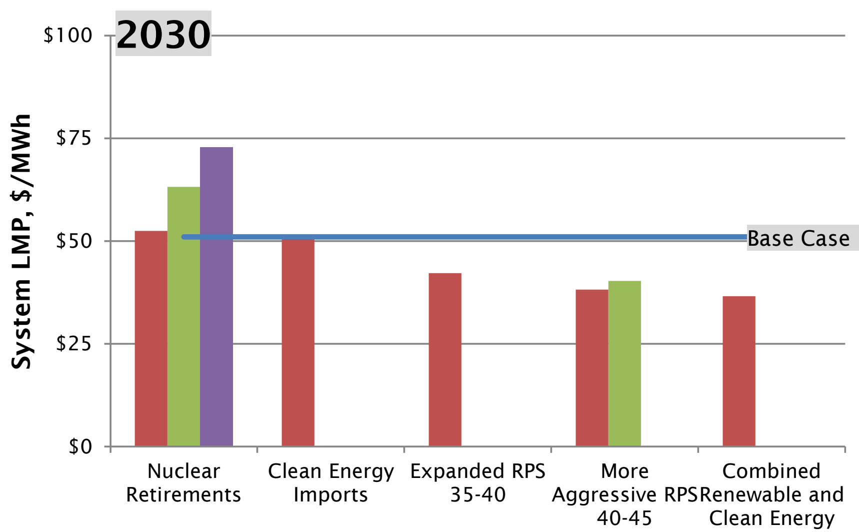
- A sensitivity was modeled where no transmission solution was built to bring wind from Northern Maine down to the Central Massachusetts load center ("More Aggressive RPS 40-45 without Transmission"). As most onshore wind is located in Maine, this sensitivity showed that without additional transmission infrastructure to bring wind from Maine to the load centers, the current transfer limits would not allow all the available wind generation to flow out of Maine

- Separate capacity prices were not modeled explicitly for the sensitivities – therefore the generation resource additions are kept the same

Scenarios with more renewables resulted in the lowest energy market costs ($/MWh) as a result of increased zero marginal cost resources (potentially increasing the need for other revenues for generators)

Wholesale Energy Market Price, $/MWh nominal





Market Prices, $/MWh nominal	2025	2030
Base Case	$48.0	$51.0
Nuclear Retirements	$49.5	$52.5
Nuclear Retirements Gas x 1.25	$59.1	$63.2
Nuclear Retirements Gas x 1.5	$67.8	$72.9
Clean Energy Imports	$46.5	$50.8
Expanded RPS 35-40	$40.1	$42.2
More Aggressive RPS 40-45	$37.0	$38.2
Expanded RPS 40-45 without Transmission	$38.9	$41.8
Combined Renewable and Clean Energy	$34.3	$36.6

- **The scenario with the lowest energy prices is the Combined Renewable and Clean Energy Scenario, which had the most aggressive renewable build out and included clean imports on top**
- **The Nuclear Retirements scenario, which was a counterfactual to the Base Case, resulted in the highest energy market prices and triggered substantial new natural gas-fired resources to replace it**
- **The More Aggressive RPS 40-45 Without Transmission scenario resulted in higher prices for the system than with transmission investment as a result of congestion along the Maine interfaces, where much of the wind resources are located**

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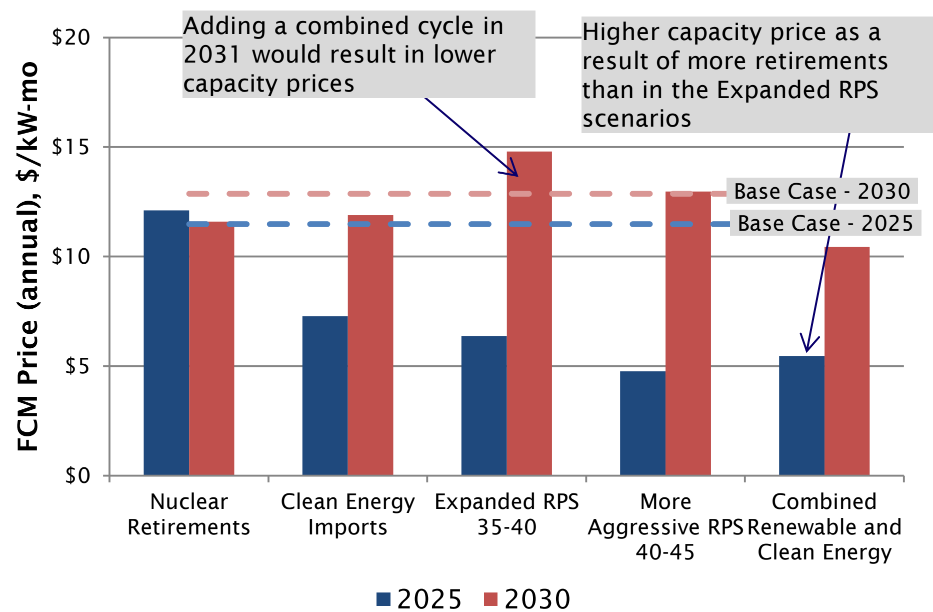
Increased supply from renewables caused capacity prices to fall in an already oversupplied market, resulting in a longer period of decreased capacity market prices (potentially increasing the need for other revenues to keep generation resources online and sustain other investment signals)

FCM Prices, $/kW-month nominal	2025	2030
Base Case	$11.5	$12.9
Nuclear Retirements	$12.1	$11.6
Clean Energy Imports	$7.3	$11.9
Expanded RPS 35-40	$6.4	$14.8
More Aggressive RPS 40-45	$4.8	$13.0
Combined Renewable and Clean Energy	$5.5	$10.4

Note: Wholesale capacity market prices only represent a snapshot at a given point in time. Larger price differences occur before 2025 depending on how many resources were added and retired

Forward Capacity Market Price, $/kW-mo nominal



- ▶ **The shortage of resources in the capacity market in the Nuclear Retirements scenario are replaced immediately by new combined cycle resources. This results in a balanced supply and demand much earlier than other scenarios**
- ▶ **In the long term, supply and demand move towards equilibrium. When the capacity market is in equilibrium, new resources will be added near the Net Cost of New Entry ("Net CONE") reference price on the demand curve – so FCM prices will tend to converge towards the same price**
- ▶ **The Expanded RPS 35-40 scenario has higher FCM prices in 2030 as there are fewer renewable resources qualifying as capacity supply than in the More Aggressive RPS 40-45 Scenario, and CCGT entry is not yet economic based on LEI's modeling. However, a CCGT was found to be economic in 2031, which would result in capacity prices closer to the other Scenarios in the next year**

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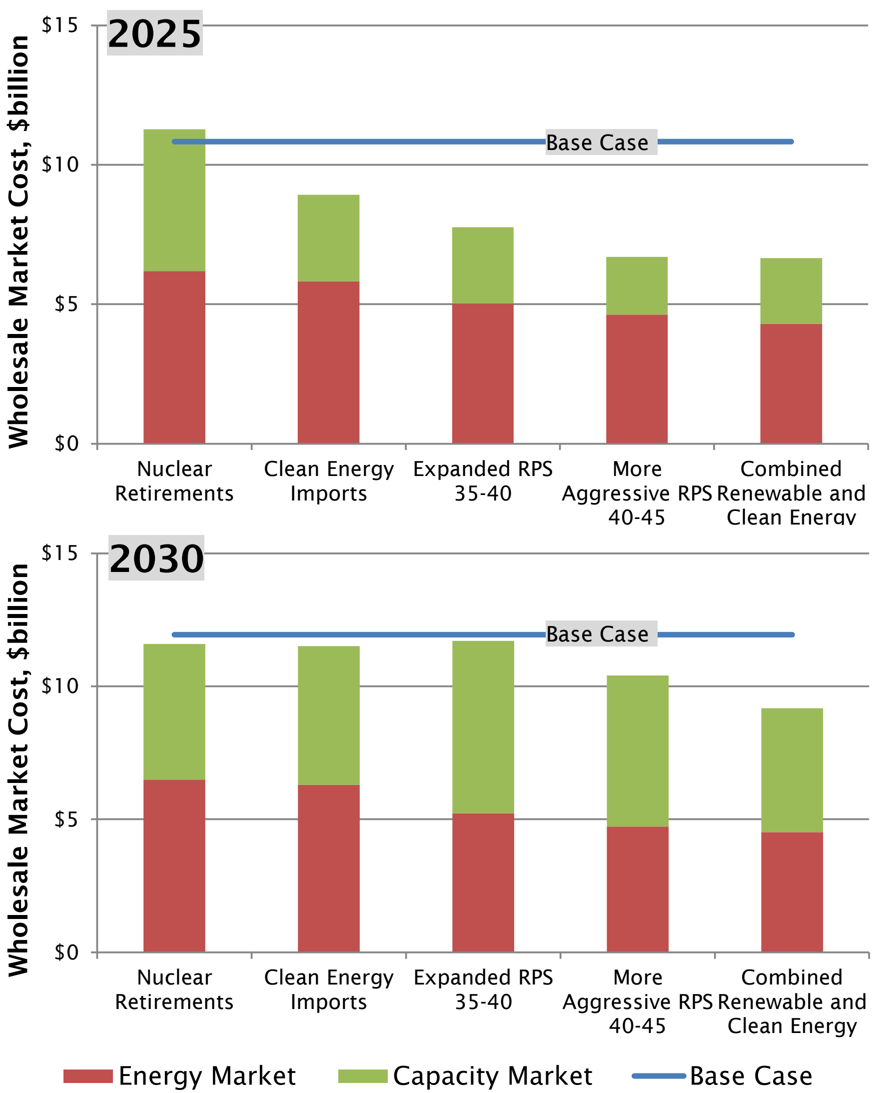
FCM costs are expected to comprise a greater share of wholesale market costs over time due to growing peak demand and as prices more closely reflect the Net Cost of New Entry

Wholesale Market Costs, $m nominal



Wholesale Costs, $b nominal	2025	2030
Base Case	$10.8	$11.9
Nuclear Retirements	$11.3	$11.6
Clean Energy Imports	$8.9	$11.5
Expanded RPS 35-40	$7.8	$11.7
More Aggressive RPS 40-45	$6.7	$10.4
Combined Renewable and Clean Energy	$6.7	$9.2

- **In 2030, the Base Case exhibited the highest wholesale market costs (which impact but are not the same as total consumer costs). Even though energy market prices are higher in the Nuclear Retirements scenario, the high level of new combined cycles entering the market reduced capacity prices enough to result in lower wholesale market costs than the Base Case (increasing the need for other revenues)**
- **The Combined Renewable and Clean Energy scenario resulted in the lowest wholesale costs due to price reduction in both energy and capacity markets (potentially increasing the need for other revenues to sustain existing generation and attract investment)**
- **Note that reported wholesale market costs in table above do not include possible uplift payments required to be paid to thermal plants being dispatched out of merit, nor do they include the costs of other revenues in furtherance of state energy and environmental laws**

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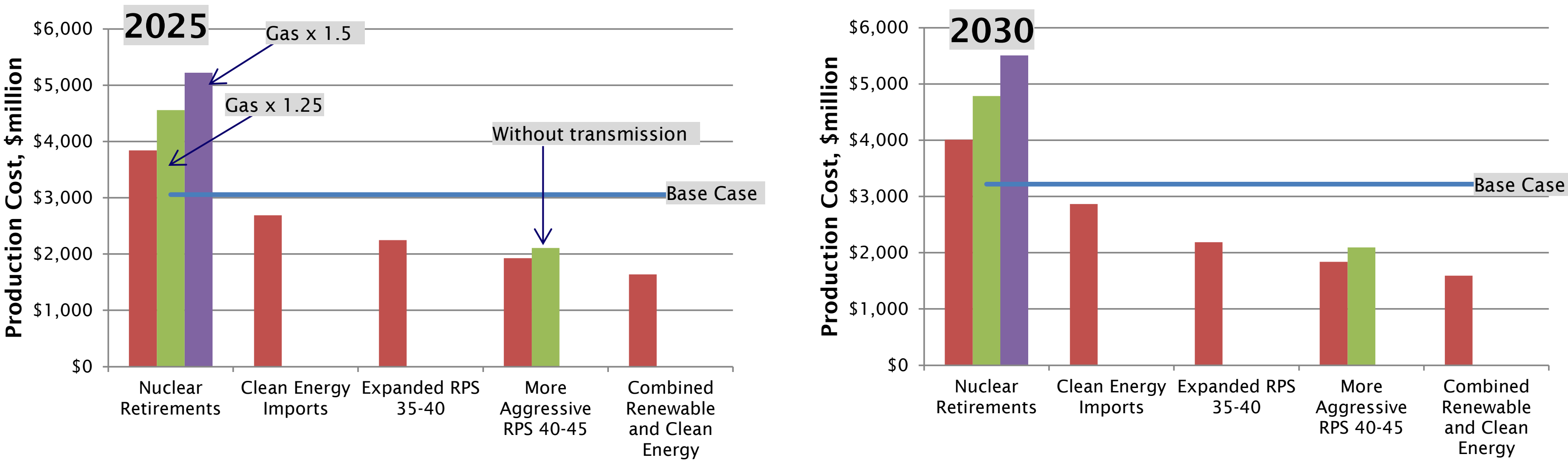
In scenarios with significant renewable energy, production costs are reduced for the entire system, as renewable generation incurs no physical short run marginal costs to produce electricity (however, the reduced production costs are not themselves sufficient to sustain generation and signal investment)

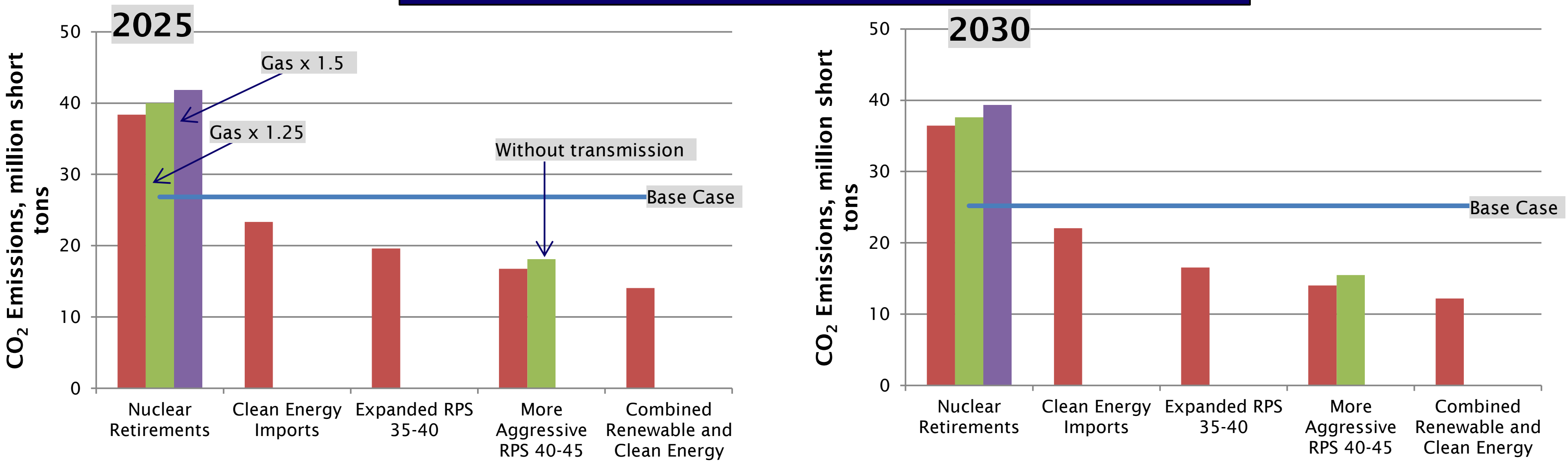
Production Costs Savings Against Base Case, $m nominal



- **Production costs is an efficiency metric that determines how efficient the system is from a short run marginal cost perspective (at the same level of output, lower production costs imply the market is more cheaply producing electricity, but is not the same as total consumer costs, nor does it reflect total economic opportunity costs accurately)**
- **The Nuclear Retirements scenario has the highest production costs because increased natural gas-fired generation (which burn higher cost fuel) is required**
  - The higher the natural gas price, the higher the production costs as the sensitivities show
- **The More Aggressive RPS 40-45 scenarios without transmission has slightly higher production costs because some of the renewable wind gets curtailed in Maine, which consequently gets replaced by higher cost resources near load (either natural gas or oil)**
- **The Combined Renewable and Clean Energy scenario has the lowest production costs due to the greatest abundance of zero marginal cost resources**

Similarly, in scenarios with significant renewable energy, system-wide CO_2 emissions decline as renewable generation is modeled as carbon-free

CO_2 Emissions Reductions, million short tons



- **Because renewable generation produces energy at zero marginal cost, it gets dispatched ahead of thermal generation which produce CO_2 and/or other greenhouse gases**
- **The Nuclear Retirement scenario (and sensitivities) has the highest carbon emissions because nuclear capacity is largely replaced by the higher CO_2 producing natural gas-fired generation**
  - Notably, the higher the natural gas price, the higher the CO_2, as there is more fuel switching from gas to oil, particularly in the winter months
- **The More Aggressive RPS 40-45 scenario without transmission has slightly higher CO_2 emissions because some of the renewable wind gets curtailed in Maine, which gets replaced by higher carbon emitting resources closer to load in Southern New England (either natural gas or oil)**

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While more renewable generation lowers wholesale market costs, it also lowers the market-based revenues and profitability of existing resources and delays market signals for new investment, suggesting a need for higher capacity payments or other revenues to sustain existing generation resources and attract new investment

Sample of expected net profits by fuel type, $/kW-yr nominal

Technology Type (Conventional)	Base Case	Nuclear Retirements	Nuclear Retirements Gas x 1.25	Nuclear Retirements Gas x 1.5	Clean Energy Imports	Expanded RPS 35-40	More Aggressive RPS 40-45	More Aggressive RPS 40-45 without Transmission	Combined Renewable and Clean Energy
2025, $/kW									
Gas Combined Cycle (existing)	$75	$85	$88	$90	$22	$2	-$19	-$20	-$12
Gas Combined Cycle (new)	-$3	$12	$20	$25	-$59	-$86	-$111	-$108	-$109
Oil Combustion Turbine	$90	$98	$99	$100	$39	$27	$7	$7	$16
Nuclear	$265	-	-	-	$200	$135	$86	$105	$62
2030, $/kW									
Gas Combined Cycle (existing)	$80	$67	$69	$71	$68	$93	$70	$70	$40
Gas Combined Cycle (new)	$2	-$4	$2	$7	-$10	-$1	-$30	-$25	-$61
Oil Combustion Turbine	$100	$85	$86	$87	$88	$122	$100	$101	$70
Nuclear	$270	-	-	-	$264	$223	$159	$213	$92

Note: see accompanying Excel sheet for full list of technologies and gross market profits

- **Expected net profits shown above are wholesale energy market and capacity market revenues less the minimum going forward costs of that specific resource type**
  - Net profits for new combined cycle plants are calculated by taking their expected wholesale energy market and capacity market revenues minus the ***all-in fixed costs*** of that resource type, which is substantially higher than the ***minimum going forward costs*** of existing generators, because all-in fixed costs include equity in addition to debt components. Transmission interconnection or system reinforcement costs are not included in this analysis
  - In principle, a negative net profit figure would suggest it is uneconomic for a new combined cycle to enter the market. However, resources are studied over their economic life, and some years of negative net profits (i.e. lower than expected outcomes) after an investment has been made will not necessarily change the investment decision. Analysis reports on single specific years (i.e., 2025 and 2030) and net profits in other years demonstrate economic justification for investment
- **Across all scenarios, the Nuclear Retirements scenarios result in the highest expected net profits**

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Capacity factors are dependent on the level of supply in the system and position of that resource in the economic dispatch merit order – more expensive generators have greater variance in capacity factors across the five scenarios and Base Case

Capacity factors by select technology (existing)

Technology Type (Conventional)	Base Case	Nuclear Retirements	Nuclear Retirements Gas x 1.25	Nuclear Retirements Gas x 1.5	Clean Energy Imports	Expanded RPS 35-40	More Aggressive RPS 40-45	More Aggressive RPS 40-45 without Transmission	Combined Renewable and Clean Energy
2025, %									
Gas Combined Cycle	33%	36%	35%	34%	31%	26%	22%	23%	20%
Oil Combustion Turbine	2%	2%	3%	3%	1%	1%	1%	1%	1%
Nuclear	91%	0%	0%	0%	91%	89%	86%	90%	78%
Biomass	71%	76%	76%	76%	70%	67%	64%	67%	61%
Solar - New	18%	18%	18%	18%	18%	18%	18%	18%	18%
Onshore Wind - New	35%	37%	37%	37%	34%	35%	35%	30%	36%
Offshore Wind - New	49%	54%	54%	54%	48%	50%	50%	50%	51%
2030, %									
Gas Combined Cycle	26%	28%	27%	27%	27%	22%	19%	21%	16%
Oil Combustion Turbine	1%	1%	2%	2%	1%	1%	0%	0%	0%
Nuclear	91%	0%	0%	0%	90%	88%	78%	89%	63%
Biomass	71%	76%	76%	76%	70%	65%	61%	65%	59%
Solar - New	18%	18%	18%	18%	18%	18%	18%	18%	18%
Onshore Wind - New	35%	37%	37%	37%	34%	35%	36%	28%	36%
Offshore Wind - New	50%	54%	54%	54%	48%	51%	50%	50%	51%

Note: Technology classifications consistent with CELT 2016. Numbers presented above are weighted averages. Some individual plants may perform at significantly higher or lower capacity factors depending on individual plant characteristics

- **Generally, thermal, dispatchable generating units have higher capacity factors under the Nuclear Retirements scenario as other resources need to run more in order to replace them; on the other hand, thermal, dispatchable generating units tend to have the lowest capacity factors under scenarios that have high renewable investment due to changes in the economic dispatch merit order and displacement**
- **Capacity factors under the RPS Expansion 40-45 with and without transmission are similar but slightly higher under the scenario without transmission. This is due to lower wind generation in Maine, and therefore other resources are needed to be dispatched**

Adding more renewables in the system reduces wholesale market revenues for new renewable resources, and therefore indicates the potential need for additional revenues (e.g. higher REC values) to bring these resources online

Break-even REC value needed*, $/MWh nominal

Technology Type (Renewable)	Base Case	Nuclear Retirements	Nuclear Retirements Gas x 1.25	Nuclear Retirements Gas x 1.5	Clean Energy Imports	Expanded RPS 35-40	More Aggressive RPS 40-45	More Aggressive RPS 40-45 without Transmission	Combined Renewable and Clean Energy
2025, $/kW									
Existing Wind (Onshore)	$8	$3	-$7	-$15	$13	$22	$26	$39	$28
New Wind (Onshore)	$34	$29	$20	$11	$38	$46	$51	$71	$53
New Wind (Offshore)	$104	$98	$88	$78	$111	$118	$123	$121	$125
Existing Solar	$73	$71	$62	$53	$79	$84	$88	$87	$90
New Solar	$64	$62	$53	$44	$70	$75	$80	$79	$82
2030, $/kW									
Existing Wind (Onshore)	$10	$6	-$5	-$15	$13	$23	$28	$42	$30
New Wind (Onshore)	$33	$29	$18	$9	$35	$44	$49	$72	$52
New Wind (Offshore)	$97	$94	$82	$72	$100	$105	$112	$108	$116
Existing Solar	$83	$83	$73	$63	$84	$85	$92	$89	$97
New Solar	$56	$56	$46	$36	$57	$59	$66	$64	$70

**Transmission interconnection costs or reinforcements were not included*
Note: see accompanying Excel sheet for complete assumptions behind the calculation of the break even REC values

- **Break-even REC values are the implied REC unit revenue that each technology type needs to receive to make it "whole" on its technology-specific all-in fixed costs (for new generation) or minimum going forward costs (for existing generation). This essentially represents the "missing money" for renewables to be built economically**
- **Wind generally has lower break-even REC values compared to solar as these units have higher capacity factors and therefore higher wholesale market revenues than solar. In addition, the needed transmission and interconnection costs for new wind resources have not been considered in the break-even REC values. Offshore wind is the most expensive due to assumed high capital costs**
- **Existing solar has higher break-even REC values than new solar as a result of new solar having lower capital costs than currently estimated for existing vintages of solar**
- **Negative REC values in the nuclear retirements scenario and sensitivities imply that those resources are profitable without REC revenues/subsidies because of higher energy prices at the level of renewable capacity additions in the Base Case**