New England 2030 Power System Study

Report to the New England Governors

2009 Economic Study:
Scenario Analysis of Renewable Resource Development

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Executive Summary

Study of the Potential for Renewables in New England

New England has significant potential for developing renewable sources of energy within the region—including substantial inland and offshore wind resources. ISO New England (ISO) has identified the potential for up to 12,000 megawatts (MW) of wind resources within New England that, if developed, would represent a major shift in the sources of energy and characteristics of resources operating in the region.[1] Such a large-scale penetration of wind resources would affect prices in New England's wholesale electricity market and total regional emissions from other types of generation sources.

In addition to significant potential for the development of renewables within New England, major wind power and hydroelectric (hydro) power development is moving forward in Québec, New Brunswick, and the other eastern Canadian provinces. Québec and New Brunswick have a long history of electric energy trade with the New England states, and expanding transmission ties to these areas would further expand the sources of renewable energy available to New England.

The ISO identified economic and environmental impacts (e.g., wholesale electricity prices and emission levels) for a set of scenario analyses hypothesizing the development of renewables as requested by the New England governors. The ISO provided this technical analysis to the governors as an economic study performed through the ISO's regional system planning process. The New England States Committee on Electricity (NESCOE), acting on behalf of the governors, submitted the request to the ISO, and the states developed the study assumptions with technical input from the ISO. The study was conducted to support the governors' efforts to develop a renewable energy blueprint for the region.

The study evaluated the integration of renewable resources, primarily wind, for a single year in the 20-year timeframe—around 2030. The study also evaluated the integration of varying levels of demand resources (i.e., energy efficiency and conservation), plug-in electric vehicles (PEVs), energy storage, and other load-modifying resources, which will be enabled by advances in "smart grid" technology. Additionally, the study evaluated possible generator retirements and the replacement or repowering of older fossil fuel generation with natural-gas-fired generation.

A final list and description of cases appears in Appendix A.

Wind and Import Cases Analyzed

The study provides the states and other stakeholders with information to evaluate many different combinations of wind power in the region.[2] The study consists of two base cases, the first with 4,000 MW of wind and the second with natural-gas-fired generation in place of wind. The study includes approximately 40 cases with varying penetrations of different technologies. The study evaluated the sensitivity of each case to higher fuel prices and the impact of transmission constraints, which produced results for more than 100 cases.

The region's widespread geographic potential for wind development allowed the ISO to evaluate multiple wind scenarios. The 12,000 MW wind scenario includes 7,500 MW of inland wind and 4,500 MW of offshore

1 The general locations of this wind potential are depicted in the map of potential wind zones (see Figure 1).

2 The study screened out potential wind resources close to urban areas and within five miles of sensitive geographic locations, such as the Appalachian Trail, and also screened out offshore wind resources that would be within three nautical miles of the shoreline.

wind. In addition to the 12,000 MW wind scenario, the study looked at 2,000 MW; 4,000 MW; and 8,000 MW incremental wind cases, of which the 4,000 MW case represents the base case.

The incremental cases are distributed evenly among inland and offshore wind resources. The inland wind scenarios are distributed among Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont; the offshore wind scenarios are distributed among Maine, Massachusetts, and Rhode Island. The study also evaluated a more targeted set of scenarios looking at 2,000 MW and 4,000 MW of offshore wind.

Table 1 shows the amount of inland and offshore wind assumed for each of the New England wind cases.

Table 1
New England Wind Cases

Case	Inland[(a)]	Offshore
2,000 MW	1,000 MW	1,000 MW
2,000 MW offshore only	0	2,000 MW
4,000 MW (base case)	2,000 MW	2,000 MW
4,000 MW offshore only	0	4,000 MW
5,500 MW	1,500 MW (near shore)	4,000 MW
8,000 MW	4,000 MW	4,000 MW
12,000 MW	7,500 MW	4,500 MW

(a) Inland resources also may be termed "onshore" resources.

The study recognizes that New England has the potential for expanding energy trade with neighboring regions. The ISO identified options for importing additional power through expanded transmission interconnections with New York (1,500 MW), Hydro Québec (1,500 MW), and New Brunswick (1,500 MW) because these areas are actively developing renewable resources and other sources of energy with low carbon emissions. Table 2 shows the amount of wind assumed from areas outside New England.

Table 2
Wind from Outside New England

Source	Wind
New York	1,500 MW
New Brunswick	1,500 MW
Québec[(a)]	1,500 MW

(a) The study also modeled imports from Québec as hydro. See *Cases Showing Increased Imports from Canada and New York* and Appendix A.

Case Combinations

After reviewing the basic study results, a few of the many possible combinations of resources that could make up the 2030 renewable resource mix in New England were further assessed. Three particular combinations of wind and hydro scenarios seem useful to compare:

1. **5,500 MW of wind**: 4,000 MW offshore and 1,500 MW inland[3]
2. **8,500 MW of wind and imports**: 5,500 MW of wind (as above) plus new tie lines with New Brunswick and Québec (1,500 MW each)
3. **15,000 MW of wind and imports**: 12,000 MW of wind (as above, plus 500 MW of offshore wind and 6,000 MW of inland wind) plus new tie lines with New Brunswick and Québec (1,500 MW each) (as above)

Highlights of the Study Results

Each of the scenarios identified in this study showed that significant new transmission investment would be required to move energy from renewable resources to customers throughout New England.

For example, New England could support the integration of approximately 8,500 MW of low-carbon resources through a combination of offshore and inland wind in New England (5,500 MW) and expanded transmission interconnections with Québec (1,500 MW) and New Brunswick (1,500 MW), for an estimated cost of approximately $10 billion of new transmission facilities in New England.

Among the key results identified in the study:

- Approximately 12,000 MW of potential wind resources in New England could be added to the system with appropriate transmission expansion. Additional renewable and low-carbon resources could be available to New England by expanding transmission interconnections to neighboring power systems.

- The analysis of transmission development required to support the integration of New England wind resources indicates that focusing on offshore wind resource integration results in the most cost effective use of new and existing transmission. This transmission configuration also allows for the integration of some near-shore inland wind resources.

- Annual wholesale electric energy prices are generally lower in cases that add renewable resources with low energy costs, such as the higher wind penetration cases, or remove energy from the system, such as the higher demand-resource penetration cases. Cases that retire large amounts of fossil fuel generators and replace those resources with the most efficient advanced combined-cycle (CC) natural-gas-fired generators also tend to produce lower energy prices.

- Energy prices are generally higher in cases that have higher loads (i.e., consumption of electricity), such as a high penetration of PEVs. (This analysis and the resulting energy prices did not include capital costs for different types of resources.)

- The results allow comparisons of the relative amount of energy produced by different types of generation for each scenario. For example, nearly 8% of the region's energy would be derived from wind, and 31% would be derived from natural-gas-fired generation in the 4,000 MW wind scenario

[3] The inland wind assumes 750 MW added in northeastern New England and 750 MW allocated 50/50 to Rhode Island and southeastern Massachusetts.

(base case), compared with 23% from wind and 18% from natural gas in the 12,000 MW wind scenario.

- The retirement and repowering scenarios produce the lowest emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_X), and carbon dioxide (CO_2). The higher wind penetration scenarios also produce significant reductions in SO_2, NO_X, and CO_2.

- PEVs would increase off-peak electricity demand, assuming customers charge PEVs during off-peak hours. PEVs could add approximately 5,000 MW of off-peak load in the scenarios with higher penetration levels. Notwithstanding the potential for PEVs to add load during off-peak hours, a higher penetration of PEVs results in higher energy prices because of the overall increase in electric loads.

- New England has opportunities to use additional energy storage beyond the amounts currently available in New England. These resources would displace higher-priced on-peak marginal resources in New England's electricity market and may duplicate some of the services that could be provided by peak-shaving demand resources. The opportunities to use energy storage were limited in this study because the study assumed that large amounts of demand resources would be used before energy storage to manage system load. Varying the amount of demand resources, or the order in which resources are used to manage system load, could alter the use of energy storage. The study only examined daily energy storage, although longer-term storage (i.e., weekly or seasonal) could provide additional benefits. The study also did not assess energy storage as an ancillary service, but this type of service may be valuable to New England.

- In evaluating only net energy market revenues for each resource type, the study shows that a typical wind resource and a typical natural-gas-fired combined-cycle resource would realize lower revenues in the high-wind-penetration cases (those cases with the lowest overall energy prices). As with all resources, the lower prices overall reduce the contribution of energy market revenues toward the resources' fixed costs and raises concerns about the adequacy of the revenue streams available to support some resources.

Introduction

This report summarizes the results of an economic study performed by ISO New England (ISO) at the request of the New England governors. [4] The study evaluated a range of generic sources of renewable energy available to New England, conceptual transmission configurations to integrate these resources into the power grid, and potential economic and environmental impacts associated with different resource scenarios. A list of the cases is included in Appendix A.

The report provides background information on regional planning, discusses the challenges for developing renewable resources, summarizes the governors' request and the assumptions and scenarios developed by the states, and presents the results of the study. The report describes conceptual transmission configurations to integrate renewable resources in New England and the estimated costs for these configurations.

The ISO's correspondence with the states, the scope of work for the study, detailed technical information related to the study, maps of potential transmission configurations, and other results are included in Appendices B, C, and D.

[4] Created in 1997, ISO New England is the independent, not-for-profit corporation responsible for reliably operating New England's 32,000 MW bulk electric power generation and transmission system, overseeing and ensuring the fair administration of the region's wholesale electricity markets, and managing comprehensive regional electric power planning. ISO New England is regulated by the Federal Energy Regulatory Commission (FERC).

As requested by the states, the ISO performed technical analysis in support of the states' efforts to develop a renewable energy blueprint; the ISO's report does not make recommendations about which resources or transmission configurations should be pursued.

The main body of the report focuses on scenarios that involve the development of renewable resources in New England and through imports of renewable resources from New York, New Brunswick, and Québec. As a supplement to the report, the ISO posted a spreadsheet in Excel format that allows the states and other stakeholders to view the study results in detail for each case (see Appendix D.) For comparison, Appendix E describes potential transmission required to support scenarios where New England would import power sourced from wind and coal in the Midwest.

Background

The six New England states have nearly four decades of experience coordinating regional planning of the electric power system—first with the New England Power Pool (NEPOOL) and now with ISO New England—and a long history of interregional planning with its neighbors in New York, Québec, and New Brunswick.

Recently, the states have sited major transmission projects throughout New England to address reliability needs identified through ISO New England's regional system planning process. Approximately $4 billion of transmission investment has been put into service since 2002, and another $5 billion is under study, in the siting process, or under construction. More than 10,000 MW of new supplies of natural-gas-fired generation have been added to the system. Additionally, the region is experiencing increased interest in developing demand resources (DRs) and renewable sources of energy. New England has recently strengthened its transmission ties to New Brunswick and New York, and several projects to strengthen ties to Québec have been proposed.

Now that New England has made significant progress addressing reliability needs, the region is well positioned to evaluate future system expansion scenarios based on economic and environmental considerations.

The New England states, acting through the New England Governors' Conference Power Planning Committee (NEGC-PPC), the New England Conference of Public Utilities Commissioners (NECPUC), the New England States Committee on Electricity (NESCOE), and the individual state utility commissions are actively involved in ISO New England's regional system planning process.

Access to Resources in Remote Locations

New England has abundant potential for developing renewable sources of energy from inland and offshore wind power generation. The challenge for the region is that a significant portion of the renewable resource potential is remote from the major population centers, so transmission would be needed to transport these supplies to the electric power grid for delivery to consumers. Figure 1 shows the locations of potential wind zones for 12,000 MW of wind resources, which are remote from load centers in New England.

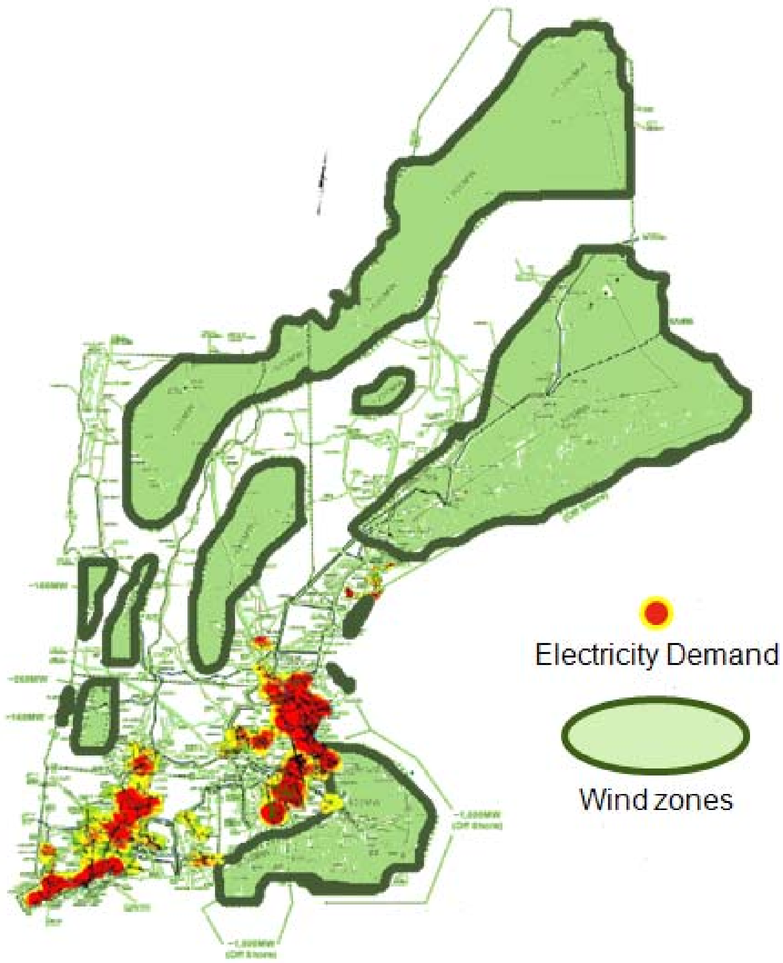

Figure 1: Potential wind zones and load centers in New England.

Request for ISO Technical Support

NESCOE and the ISO initiated the study early in 2009 (see Appendix B). On January 22, 2009, Maine Governor John Baldacci submitted a letter to the ISO requesting assistance to support the states' efforts to develop a regional vision for developing renewable energy. On February 2, 2009, ISO New England President and CEO Gordon van Welie replied to Governor Baldacci offering the ISO's support of the states' renewable initiative.

NESCOE submitted a letter to the ISO on March 27, 2009, on behalf of the governors of the six New England states, requesting the ISO to conduct an economic study pursuant to its federally-approved regional planning process.[5] Specifically, NESCOE requested that ISO study "potential renewable generation in New England and the associated transmission infrastructure required to integrate them." NESCOE further explained that the purpose of the request is "to advance the broad objective of identifying the significant sources of renewable energy available to New England, the most effective means to integrate them into our power grid, and

[5] ISO New England Open Access Transmission Tariff, Attachment K. http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/index.html.

estimated costs." NESCOE presented the request to the PAC on March 31. The NESCOE Web site provides updates of the actions of the New England governors to develop a renewable energy blueprint.[6]

The states, through NESCOE, developed the study assumptions with technical support from the ISO (see Appendix C). The ISO provided information and analysis to serve as a basis for the states to develop the governors' vision for a regional blueprint for New England. These assumptions have been discussed with regional stakeholders through a formal process with the PAC. In July, as requested by the New England states, the ISO updated the New England Congressional Delegation staff on the economic study and the associated transmission configurations as part of a briefing in Washington, D.C., arranged by the New England states (see Appendix D).

As requested, this study identifies potential transmission to integrate a range of renewable resource expansion scenarios and preliminary cost estimates for this transmission.[7] These transmission configurations were developed as overlays on the New England bulk power system in addition to the reliability projects identified for the 10-year horizon of the ISO's regional system planning process.

The "Scenario Analysis" Approach for Economic Studies

The ISO conducted an analysis in 2007 that evaluated the reliability, economic, and environmental impacts of various future system expansion scenarios. The ISO performed this "scenario analysis" through an open stakeholder process with a steering committee that included representatives from the New England states. The ISO published the final *New England Electricity Scenario Analysis* report in August 2007.[8] Among other findings, the report showed significant economic and environmental benefits attributable to scenarios that added large amounts of energy efficiency, non-carbon-emitting and other renewable sources of energy. The 2007 scenario analysis approach has served as the model for subsequent economic studies, which are conducted annually as part of the ISO's regional system planning process. These studies are among several enhancements the Federal Energy Regulatory Commission (FERC) made to the planning process in 2007 required of all transmission planning authorities.[9]

The Stakeholder Process

The ISO conducted this study as part of its regional system planning process and in 2009 reviewed the scope of work, assumptions, and scenarios with the region's stakeholders through the PAC. The states presented their request to the PAC in March 2009 and reviewed the detailed study assumptions with the PAC in May. The ISO provided the study results to the PAC in July for discussion with stakeholders in August.

Overview of the Study Objective

The objective of this study is to evaluate a hypothetical future power system under a range of scenarios based on several assumptions. The study for the governors evaluates the integration of renewable resources (i.e., focused on wind resources), demand resources (i.e., energy efficiency and conservation), natural-gas-fired

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[6] See www.nescoe.com.

[7] The ISO retained the consulting firm, Energy Initiatives Group (EIG), to develop the transmission maps and cost estimates for this study; see www.eig-llc.com.

[8] *New England Electricity Scenario Analysis: Exploring the Economic, Reliability, and Environmental Impacts of Various Resource Outcomes for Meeting the Region's Future Electricity Needs* (ISO New England, August 2, 2007); http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/elec_report/index.html.

[9] *Preventing Undue Discrimination and Preference in Transmission Service, Final Rule*, 18 CFR Parts 35 and 37, Order No. 890 (Docket Nos. RM05-17-000 and RM05-25-000), (Washington, DC: FERC, February 16, 2007); http://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

generation, PEVs, energy storage, and other resources for a single year in the 20-year timeframe—around 2030. The study also evaluated systemwide metrics surrounding possible generator retirements, the repowering of older fossil fuel generation, and the expansion of interconnections with neighboring regions. The study evaluated the future New England system as a region; state-by-state results are not presented as part of this analysis because the New England bulk power system and wholesale electricity markets are operated on a regional basis and do not consider political subdivisions when dispatching resources to serve the region's demand for electricity.

The study approach was to conduct a "what if" analysis based on a specific set of assumptions. The results inform the states and stakeholders of economic and environmental impacts that might reasonably be expected to occur *if* one electric technology or set of electric technologies were pursued over another.

Advances in "smart grid" technology in the 20-year timeframe will enable large-scale development of demand resources, PEVs, energy-storage technologies, and other emerging technologies, which are modeled generically in this study. The study does not include explicit assumptions for government or industry actions to bring about smart grid technology.

Because of global uncertainties, this analysis did not predict what future fuel prices would be in New England or prescribe one particular scenario over another. Rather, it presented a base-case outlook and developed a range of results for the different technologies, based on the U.S. Department of Energy's fuel-price forecasts for oil, natural gas, and coal.

Furthermore, the analysis did not consider a full economic impact model of the region. It did not evaluate, for example, changes in economic development, demographic changes, job impacts, or changes in technological innovation. Although this analysis presents a variety of economic results for comparison, it was not a least-cost plan or multi-year, present-worth analysis, and it did not include a "feedback loop" that accounted for how consumers or investors would react to the different sets of circumstances presented. Additionally, the analysis did not identify "right" or "wrong" technologies, attempt to build consensus about "preferable" technologies or outcomes, or develop a plan for what the region *should* or *will* do.

General Assumptions and Metrics

The study is based on assumptions for supply and demand levels for New England; the penetration of demand resources, PEVs, wind, and energy storage; generator retirements, and expanded interconnections with neighboring regions (see Appendix C). The study evaluated approximately 40 cases and several sensitivities. It evaluated a range of assumptions (i.e., low, medium, and high levels of resource additions, retirements, and demand resources) for each New England scenario and several sensitivities to various parameters (e.g., higher fuel prices and the effect of transmission constraints) for all cases.

The study evaluated the sensitivity of the bulk power system that was "constrained" by the transmission interface limits modeled in the 2009 *Regional System Plan* (RSP09).[10] The study also evaluated the system without these constraints (i.e., "unconstrained"). Transmission constraints are physical limitations on the bulk power system that limit the ISO's ability to dispatch the lowest-priced resources to meet the region's demand for electricity. When this occurs, the ISO may have to dispatch higher-priced resources, and the incremental cost is reflected in wholesale electricity prices as congestion costs. The unconstrained cases in this study represent the transmission system in 2030 assuming the completion of the projects in the ISO's Regional System Plan and the transmission-expansion configurations developed specifically for this study. The study presents metrics for both a constrained and an unconstrained system.

In cases that model existing transmission constraints and higher penetrations of wind, the system would not be able to operate without substantial transmission reinforcement. The resources in these scenarios could not be

[10] The interface limits modeled in the economic study assume the completion of the New England East–West Solution (NEEWS) and the Maine Power Reliability Project (MPRP) transmission projects identified in the Regional System Plan.

fully integrated into the electric system reliably without the transmission configurations that accompany this study.

The transmission configurations in this study have been sized and configured to create representative, robust, fully functional system expansions for the benefit of the entire New England region. These conceptual transmission configurations have not been technically optimized, nor have they been subjected to rigorous and detailed transmission system analysis. A complete system impact study would be required for all components of any plan in the future. The conceptual transmission configurations identified as part of this study are depicted on the New England geographic map for illustration purposes only and do not represent the future locations of facilities.

The study evaluated net energy market revenues and does not account for other sources of revenue, such as capacity markets, ancillary service markets, or markets for renewable energy certificates (RECs).[11] Table 3 outlines the economic metrics, and Table 4 outlines the environmental metrics used to compare the results across all cases.

Table 3
Economic Metrics

Metric	Measure
Load (electric energy consumed)	gigawatt-hours (GWh)
Load-serving entity (LSE) energy expense	millions of dollars
Production costs	millions of dollars
Average clearing prices	dollars per megawatt-hour ($/MWh)

Table 4
Environmental Metrics[(a)]

Metric	Measure
Sulfur dioxide (SO_2) emissions	1,000 tons (ktons)
Nitrogen oxide (NO_X) emissions	1,000 tons (ktons)
Carbon dioxide (CO_2) emissions	million tons (mtons)

(a) The study does not evaluate the environmental impact of the decreased use of gasoline associated with the increased use of PEVs, or the impact of the decreased use of heating oil associated with the increased use of electric heat.

Fuel-Price Assumptions and Sensitivity

The study assumed fuel prices through 2030 from the 2009 Energy Information Administration (EIA) *Annual Energy Outlook*.[12] EIA projects higher natural gas and oil prices over the long term relative to 2008 prices and generally stable coal, biomass, and nuclear prices over the long term. The ISO study included a sensitivity for higher fuel prices. For this sensitivity, the ISO increased natural gas prices by a factor of two, distillate fuel oil prices by a factor of 1.75, and residual fuel oil prices by a factor of 1.5.

[11] A *Renewable Energy Certificate* represents the environmental attributes of one megawatt-hour of electricity from a certified renewable generation source for a specific state's Renewable Portfolio Standard. Providers of renewable energy are credited with RECs, which are usually sold or traded separately from the electric energy commodity.

[12] Energy Information Administration*, 2009 Annual Energy Outlook,* DOE/EIA-0383 (Washington DC: U.S. DOE, April 2009); http://www.eia.doe.gov/oiaf/aeo/index.html.

Fuel Consumption

The study evaluated fuel consumption for each case. The results show generation by fuel type in gigawatt-hours and percentage for the total New England system and for individual resource types, such as coal, natural gas, nuclear, wind, demand resources, and hydro.

Emission Allowance Prices

The study evaluated the effect of allowance prices for emission of carbon dioxide, sulfur dioxide, and nitrogen oxides. CO_2 allowances were assumed to be $10 per ton, while SO_2 was assumed to be $350 per ton. A NO_X emission value of $700 per ton was assumed to be applied to all emissions from Connecticut, Massachusetts, Rhode Island, and New Hampshire because of ozone standard attainment strategies assumed in RSP08.

The Cases

Approximately 40 cases and several sensitivities were evaluated. The study assumed hypothetical levels of future resource additions (and attrition) and compared economic and environmental results for each case.

Base Case

The base case for the study assumed that all existing generating resources are operational with no generator retirements. The base case adds active and passive demand resources, PEVs, and 4,000 MW of wind evenly distributed among inland and offshore locations.[13] It also assumes a base level of electric heating conversion in Maine.

The study includes an alternative base case that replaces 4,000 MW of new wind resources with 1,500 MW of natural-gas-fired combined-cycle generation, which would provide an equivalent amount of energy. The base case and all other cases assume the addition of 400 MW total of wind and biomass in northern New Hampshire.

After reviewing the basic study results, a few of the many possible combinations of resources that could make up the 2030 renewable resource mix in New England were assessed. Three particular combinations of wind and hydro scenarios were compared:

1. **5,500 MW of wind**: 4,000 MW offshore and 1,500 MW inland[14]

2. **8,500 MW of wind and imports**: 5,500 MW of wind plus new tie lines with New Brunswick wind and Québec hydro (1,500 MW each)

3. **15,000 MW of wind and imports**: 12,000 MW of wind plus new tie lines with New Brunswick wind and Québec hydro (1,500 MW each)

[13] Passive demand resources are devices or technologies that reduce energy consumption during the peak and throughout the year, such as efficient lighting. Active demand resources are resources that reduce energy consumption when called on by the ISO, such as load management or distributed generation.

[14] The case assumes the inland addition of 750 MW in northeastern New England and the equal allocation of a total of 750 MW to Rhode Island and southeastern Massachusetts, also inland.

Regional Peak Demand and Demand-Resource Cases

The study extrapolated the load growth in the ISO's 2009 forecast out to 2030, which projects a system peak of approximately 34,500 MW. The forecast treats energy-efficiency measures, demand response, and real-time emergency generation (RTEG) as supply resources.

The study evaluated three separate demand-resource scenarios to bracket the possible range of demand-resource penetration in the region (i.e., low, medium, and high penetration). Each of these three scenarios includes combinations of passive and active demand resources. The base case includes medium-level passive demand resources equivalent to 10% of system peak demand (3,450 MW), plus 3,100 MW of active demand resources, plus 800 MW of emergency generation. The study shows the use of passive demand resources throughout the year, the use of active demand resources during the summer, and the use of emergency generation for up to 30 hours during the year.[15]

Plug-in Electric Vehicles Cases

The study established three separate scenarios based on a range of penetrations. The high case is based on Oak Ridge National Laboratories' projections of 2.5 million PEVs operating in New England by 2030.[16] The ISO established scenarios for a medium base case and a low PEV case based on achieving two thirds and one third, respectively, of Oak Ridge's 2.5-million PEV projection. The study assumed that PEVs would charge off peak and would not provide energy storage for the grid. However, the effect of vehicle-to-grid power supply is simulated in the energy-storage scenarios (see below). The study assumed approximately 5,000 MW of nighttime load for the high penetration case for PEVs and approximately 1,700 MW of nighttime load for the low penetration case.

Energy-Storage Cases

Energy-storage technologies consume energy during off-peak hours when prices are lower and provide energy to the grid during peak hours when prices are higher. Energy storage has the effect of flattening the system load each day by shifting demand from on peak to off peak hours. Examples of storage technologies include pumped storage hydro (PS), batteries, compressed air, or other emerging technologies.

The study established several generic scenarios to bracket the possible range of new energy-storage technologies, from 1,000 MW to 5,000 MW. In the study, energy storage was used as a load modifier after other demand resources assumed in the study had been dispatched. Energy storage was assumed to be adequate for flattening loads throughout a day but not for storing energy across weeks or months. The long-term horizon for the study allowed for emerging technologies to be deployed commercially.

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[15] Activation hours assumed in this analysis were significantly above the levels envisioned in the ISO's 2007 Scenario Analysis when approximately 200 hours of activation was assumed. This analysis shows 300, 500, and 700 hours of activation for the low, medium, and high demand-resource cases. Real-time emergency generation would be activated between 20 and 30 hours for these penetration levels.

[16] Stanton W. Hadley and Alexandra Tsvetkova*, Potential Impacts of Plug-in Hybrid Electric Vehicles on Regional Power Generation* (ORNL/TM-2007/150) (Oak Ridge, TN: U.S. Department of Energy, Oak Ridge National Laboratory, January 2008); http://www.ornl.gov/info/ornlreview/v41_1_08/regional_phev_analysis.pdf.

Generator Retirements and Repowering Cases

The study established three separate age thresholds to model the retirement and repowering of existing generation. The study evaluated the retirement or repowering of existing coal and oil units that have been in service more than 50, 60, and 70 years as of 2030.

The study replaced the retired fossil units with new highly efficient natural-gas-fired combined-cycle units of the same size. These advanced combined-cycle replacement units are assumed to operate at a heat rate of 6,500 British thermal units/kWh (Btu/kWh).[17] This rate is more efficient than today's typical combined-cycle unit operating at 7,300 Btu/kWh, which is typical of the marginal, or price-setting, units in the New England energy market. The retirement cases assumed the full replacement of the existing equipment with the most advanced technology combined-cycle equipment resulting in the highest efficiency.

In the repowering cases, the study replaced the older fossil units with natural-gas-fired generators that are assumed to operate with a heat rate of 8,500 Btu/kWh. This is more efficient than the original resources but less efficient than the advanced combined-cycle units assumed to replace retired generators. The repowering cases assumed that some of the original equipment would be used and the combination of existing and new equipment would not achieve the efficiency of a new advanced combined-cycle unit. Dispatching these repowered resources could be more or less expensive depending on whether the repowered resource is replacing coal or oil. The assumptions document (Appendix C) provides a breakdown of the age of existing generation in 2030.

The study also assumed the conversion of fossil generators in service more than 70 years to burn biomass, subject to unit size constraints. The study assumed relicensing of existing nuclear power plants.

Maine Electric Heat Conversion Cases

The study assumed different levels of conversion of oil heating in Maine to electric heating based on the state of Maine achieving electric heat penetration similar to other New England states. The base case assumed a base amount of conversion. Other cases assumed high and low levels of additional conversion. The study developed an assumed typical day in April that would have no heating load and subtracted that from the load profile for all other days in the year to identify the approximate amount of heating load in Maine. The results show the effect of increasing electric loads during nonsummer months. Additionally, loads potentially can increase during the summer months if groundwater heat pumps are used for air conditioning.

Cases Showing Increased Imports from Canada and New York

The study assumed multiple transmission-expansion configurations to allow additional imports from Eastern Canada and New York for various cases. These cases include 1,500 MW of wind from New Brunswick; 1,500 MW of hydro from Québec; 1,500 MW of wind from Québec; and 1,500 MW of wind from New York.[18] For the New Brunswick and Québec scenarios, the study assumed that additional transmission would be required to enable the additional imports. For the New York scenario, the study assumed that the wind energy would flow over the existing New York—New England transmission interface.

[17] Btu is the measure of the energy content of fuel. Heat rate is the measure of a thermal generator's efficiency at converting energy (from burning fuel) into electricity. A generator with a lower heat rate is more efficient than a generator with a high heat rate because it can produce a kilowatt-hour of electricity using less energy.

[18] The study models the additional hydro imports from Québec in two ways. One way is with this power flowing into New England from Québec when the energy from Québec is in economic merit order (i.e., "economic") in the New England energy market based on assumed bidding strategies, similar to the present import structure with Hydro Québec imports. The second way is assuming the imports have a high (63%) capacity factor and are dispatched as resources in the New England market willing to operate at any price and not eligible to set clearing prices.

Four Primary Wind Scenarios

The study focused primarily on wind scenarios as the potential sources of renewable power in the region.

The study evaluated the integration of up to 12,000 MW of wind resources in New England including 7,500 MW of inland wind and 4,500 MW of offshore wind (see Table 1 and Table 2).[19] The wind capacity numbers in this study are based on nameplate ratings. A resource with a 100 MW nameplate capacity rating can provide a maximum of 100 MW of output. Wind turbines are considered intermittent (i.e., variable) resources because the amount of power they supply to the grid varies depending on the amount of wind blowing. Significantly more wind capacity is needed to produce the equivalent energy output of a resource that can operate continuously, such as a natural-gas-fired combined-cycle generator.

Offshore wind was assumed to have a capacity factor of 40.7%. Inland wind was assumed to have a capacity factor of 29.3% in Maine and 35.4% in the rest of New England.

For comparison of the proposed penetration of wind capacity with the level of existing installed wind capacity, approximately 100 MW of wind resources currently are operating in the region, and approximately 3,700 MW of wind projects are proposed.[20] As of summer 2009, New England has 31,400 MW of total installed generating capacity.

The study established several wind-penetration scenarios to bracket the possible range of wind installations in the region in the 20-year timeframe. In addition to the 12,000 MW case, the study evaluated three incremental wind cases (i.e., 2,000 MW; 4,000 MW; and 8,000 MW). The incremental cases are distributed evenly among inland and offshore locations. The inland wind is distributed among Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. The offshore wind projects are distributed evenly between Maine, Massachusetts, and Rhode Island in all cases.

A state-by-state breakdown of the wind cases is described in detail in the assumptions document (see Appendix C).

Targeted Wind Cases

In addition to the initial 2,000 MW; 4,000 MW; 8,000 MW; and 12,000 MW wind cases noted above, the study analyzed 2,000 MW and 4,000 MW offshore wind cases. The offshore wind is distributed consistent with the basic wind studies, with the resources distributed evenly off the coasts of Maine, Massachusetts, and Rhode Island.

The study includes maps of potential wind zones for the 12,000 MW case and several incremental wind cases. The study also includes maps of potential new transmission and substation configurations to interconnect wind resources in each of these zones to key New England load centers (see Appendix D). Representative maps are included in this report.

The ISO and EIG estimate that higher voltage classes (500 kV and 765 kV) most likely would need to be introduced to the existing 345 kV transmission system for the larger wind penetration cases (i.e., 4,000 MW or above).[21]

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[19] The level of wind tested in this study is consistent with the assumptions the ISO is using for a more detailed, operations-focused wind integration study, which is being conducting in parallel with this economic study. The wind-integration study is expected to be complete in summer 2010.

[20] The level of proposed wind resources is based on the level of resources in the ISO Generator Interconnection Queue as of March 15, 2009, *2009 Regional System Plan.*

[21] Developing an increasingly large level of new resources and moving the resulting energy over long distances requires higher voltage transmission to minimize losses and to allow a configuration that is robust enough for reliable system

For relatively substantial wind areas possessing little robust existing transmission, the study assumed that wind resources would connect to "local" transmission loops or dual-circuit radials. These circuits would deliver wind-generated energy to "backbone" transmission circuits designed to reliably transport that energy to key southern New England load centers. For purposes of this study, local loops, radials, and all backbone circuits are assumed to overlay the existing transmission system. It was further assumed that relatively small and dispersed wind resources would connect to the existing transmission system and that all wind resources would connect to existing or new transmission at a 115 kV voltage level.

Wind Site Screening

The study screened out potential wind development in certain geographic locations (e.g., in areas with high elevation or slope or in proximity to urban areas) where development was considered infeasible for technical or other reasons. For example, the study assumes a five mile buffer around the Appalachian Trail (in each of the affected states) and around the Long Trail (in Vermont), which precludes potential inland wind development in areas with some of the best wind regimes (i.e., higher wind speeds).

The ISO adapted the wind potential for this study from estimates in a 2008 study conducted by Levitan & Associates Inc. (LAI) for the ISO.[22] LAI applied several screens that eliminated potential wind sites due to high population density, low wind speeds, and lack of commercial scale (i.e., areas with inland potential below 40 MW and offshore potential below 200 MW). LAI eliminated potential wind sites farther than 40 miles from the existing bulk electric transmission system and offshore sites within three nautical miles of the shore and in water deeper than 30 meters.

The ISO did not evaluate the feasibility of siting specific wind or transmission projects as part of the study. *The potential transmission identified as part of this study is depicted on the New England geographic map for illustration purposes only and does not represent the future location of facilities.* Table 5 shows an overview of the type and total circuit miles of transmission that would be needed for the study's potential wind scenarios.

Table 5
Overview of Potential Transmission

Case Description	Potential Transmission and Related System Upgrades	Potential New Transmission Circuit Miles
2,000 MW	345 kV and 115 kV local loops and radials in NH and ME to connect inland and offshore wind Single-circuit overhead 345 kV backbone, central ME–Millbury–Manchester, and single-circuit overhead 345 kV backbone to high-voltage direct-current (HVDC) submarine cable, ME–Boston to move energy to load centers Upgraded coastal substations in MA and RI with reinforced 115 kV to connect offshore wind Other small disbursed inland and offshore wind connect to existing 115 kV substations	1,785

operation during system contingency events. As an example, the use of these higher voltage classes to move power over long distances is the basic design of the Hydro Québec system. The existing transmission tie between the Des Cantons substation in Québec and the Sandy Pond substation in Massachusetts is a +/- 450 kV HDVC line.

[22] *Phase II Wind Study* (Levitan & Associates, Inc., March 2008); http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2008/may202008/lai_5-20-08.pdf.

Case Description	Potential Transmission and Related System Upgrades	Potential New Transmission Circuit Miles
2,000 MW offshore only	345 kV local loop in ME to connect offshore wind Single-circuit overhead 345 kV backbone, central ME–Millbury–Manchester, and single-circuit overhead 345 kV backbone to HVDC submarine cable, ME–Boston to move energy to load centers Upgraded coastal substations with reinforced 345 kV and 115 kV to connect offshore wind in MA, RI Other small disbursed inland and offshore wind connect to existing 115 kV substations	1,015
4,000 MW (base case)	345 kV and 115 kV local loops and radials in NH and ME to connect inland and offshore wind Dual-circuit overhead 345 kV or 500 kV backbone through most of interior New England Energy assumed to be delivered to Southington and Manchester substations in Connecticut and the Millbury and Tewksbury substations in Massachusetts Upgraded coastal substations with reinforced 345 kV and 115 kV to connect offshore wind in MA, RI Other small disbursed inland and offshore wind connect to existing 115 kV substations	3,615
4,000 MW offshore only	345 kV local loop in ME to connect offshore wind Dual-circuit overhead 345 kV backbone, central ME–Millbury–Manchester and single-circuit overhead 345 kV backbone to HVDC submarine cable to move energy to load centers Energy assumed to be delivered to same four locations in southern New England identified above Upgraded coastal substations with reinforced 345 kV and 115 kV to connect offshore wind in MA, RI Other small disbursed inland and offshore wind connect to existing 115 kV substations	1,430
5,500 MW	Same as 4,000 MW offshore-only case	1,430
8,000 MW	345 kV and 115 kV local loops and radials in NH and ME to connect inland and offshore wind Dual-circuit overhead 500 kV or 765 kV backbone through most of interior New England Energy assumed to be delivered to same four locations in southern New England identified above Upgraded coastal substations with reinforced 345 kV and 115 kV to connect offshore wind in MA, RI Other small disbursed inland and offshore wind connect to existing 115 kV substations	4,320
12,000 MW	Same as 8,000 MW case	4,320

2,000 MW Wind Case

The 2,000 MW wind case contemplates new 345 kV and 115 kV local loops and radials in Maine and New Hampshire to connect inland and offshore wind resources. These local circuits would connect to one new backbone 345 kV overhead circuit travelling from central Maine to Millbury, Massachusetts, continuing to Manchester, Connecticut; and one new backbone 345 kV overhead to an HVDC submarine cable travelling from Maine to Boston. Major areas of offshore wind resources in Massachusetts and Rhode Island would connect to upgraded coastal substations with reinforced 115 kV transmission. Smaller, dispersed inland and offshore wind resources would be connected to existing substations at a 115 kV voltage level. This scenario would require approximately 1,785 circuit miles of new transmission.

2,000 MW Offshore Wind Case

The 2,000 MW offshore-only wind case contemplates one new 345 kV local loop in Maine to connect wind resources to one new backbone 345 kV overhead circuit travelling from central Maine to Millbury, Massachusetts, continuing to Manchester, Connecticut; and one new backbone 345 kV overhead to an HVDC submarine cable travelling from Maine to Boston. Major areas of offshore wind resources in Massachusetts and Rhode Island would connect to upgraded coastal substations with reinforced 345 kV and 115 kV transmission. Likewise, smaller, dispersed offshore wind resources would be connected to existing coastal substations at a 115 kV voltage level. This scenario would require approximately 1,015 circuit miles of new transmission.

4,000 MW Wind Case

The 4,000 MW wind case contemplates a number of 345 kV and 115 kV local loops and radials in Maine and New Hampshire connected to a new three-subloop, dual-circuit overhead 345 kV or 500 kV backbone transmission system overlaying most of the interior of New England. Major offshore wind resources in Massachusetts and Rhode Island would connect to upgraded coastal substations via reinforced 345 kV and 115 kV transmission. Smaller, dispersed inland and offshore wind resources would be connected to existing substations at a 115 kV voltage level. For all configurations contemplating 4,000 MW or more of wind, the energy is assumed to be delivered by new backbone transmission to the same four locations in southern New England: the Southington and Manchester substations in Connecticut, and the Millbury and Tewksbury substations in Massachusetts. If future detailed planning studies show that this scenario cannot be implemented at the 345 kV level, 500 kV transmission would be used. This configuration would require approximately 3,615 circuit miles of new transmission.

4,000 MW Offshore Wind Case

The 4,000 MW offshore-only wind case contemplates a single new 345 kV local loop in Maine to connect wind resources to two new backbone 345 kV overhead circuits travelling from central Maine to Millbury, Massachusetts, continuing to Manchester, Connecticut; and one new backbone 345 kV overhead to an HVDC submarine cable travelling from Maine to Boston. Major areas of offshore wind resources in Massachusetts and Rhode Island would connect to upgraded coastal substations with reinforced 345 kV and 115 kV transmission. Smaller, dispersed offshore wind resources would be connected to existing coastal substations at a 115 kV voltage level. This configuration would require approximately 1,430 circuit miles of new transmission. This configuration is depicted, as a representative example, in Figure 2.

5,500 MW Wind Case

The 5,500 MW wind case combines the 4,000 MW offshore-only wind case with 1,500 MW of near-shore inland wind resources. The inland wind assumes 750 MW added in northeastern New England and 750 MW allocated 50/50 to Rhode Island and southeastern Massachusetts. The 5,500 MW wind case is assumed to use the same transmission configuration as the 4,000 MW offshore wind case.

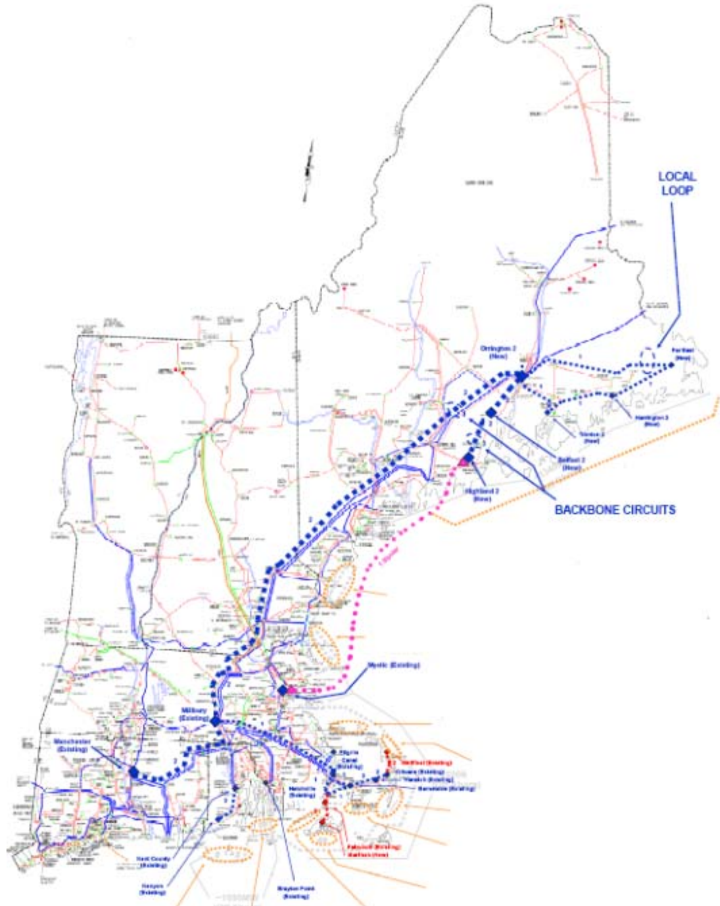

Figure 2: Potential transmission for the 4,000 MW offshore wind scenario (conceptual illustration only).

8,000 MW Wind Case

The 8,000 MW wind case contemplates a number of 345 kV and 115 kV local loops and radials in Maine and New Hampshire connected to a new three-subloop, dual-circuit overhead 500 kV or 765 kV backbone transmission system overlaying most of the interior of New England. Major offshore wind resources in Massachusetts and Rhode Island would connect to upgraded coastal substations via reinforced 345 kV and 115 kV transmission. Smaller, dispersed inland and offshore wind resources would be connected to existing substations at a 115 kV voltage level. If future detailed planning studies show that this configuration cannot be implemented at the 500 kV level, 765 kV transmission would be used. This configuration would require approximately 4,320 circuit miles of new transmission.

12,000 MW Wind Case

The 12,000 MW wind case contemplates a number of 345 kV and 115 kV local loops and radials in Maine and New Hampshire connected to a new three-subloop, dual-circuit overhead 500 kV or 765 kV backbone transmission system overlaying most of the interior of New England. Major offshore wind resources in Massachusetts and Rhode Island would connect to upgraded coastal substations via reinforced 345 kV and 115 kV transmission. Smaller, dispersed inland and offshore wind resources would be connected to existing substations at a 115 kV voltage level. If future detailed planning studies show that this scenario cannot be implemented at the 500 kV level, 765 kV transmission would be used. This configuration would require approximately 4,320 circuit miles of new transmission. This configuration, which is very similar to the 8,000 MW case, is depicted as a representative example in Figure 3.

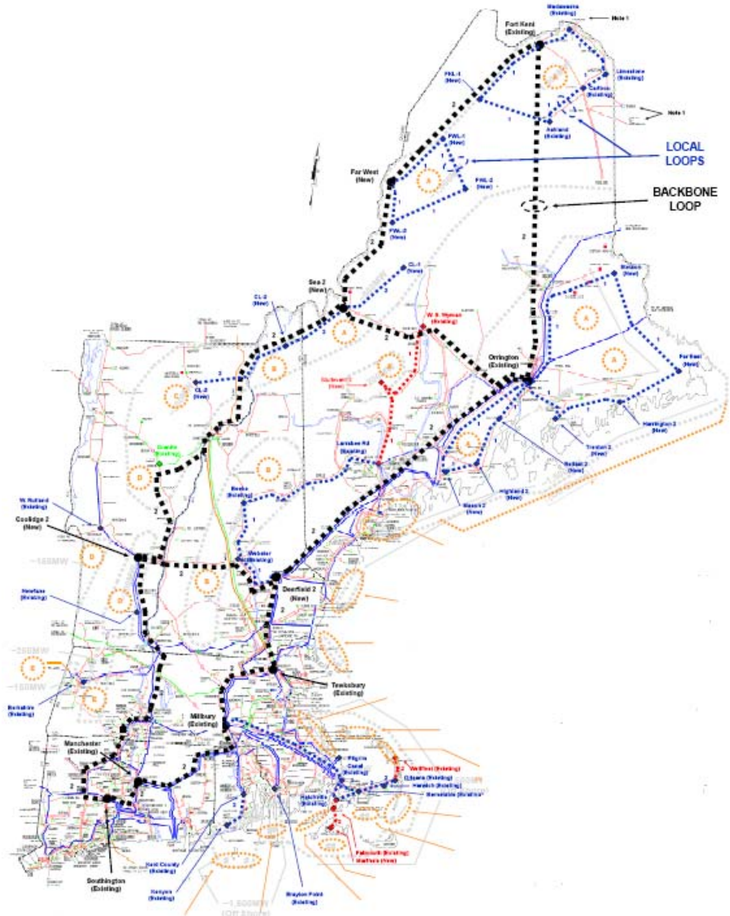

Figure 3: Potential transmission for the 12,000 MW wind scenario (conceptual illustration only).

Additional maps of these transmission configurations are posted on the ISO Web site (see Appendix D).

Interconnection-Expansion Cases

Figure 4 shows potential configurations to expand New England's transmission interconnections with New Brunswick and Québec.

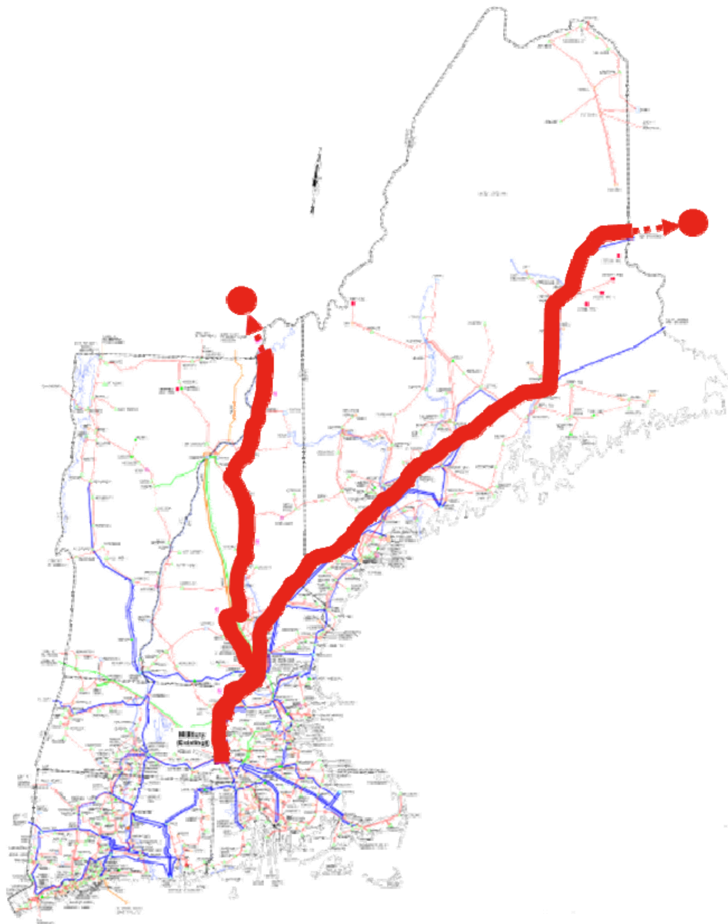

Figure 4: Potential transmission for the New Brunswick and Québec interconnection scenarios (conceptual illustration only).

Cases Delivering Resources from New Brunswick and Québec

The New Brunswick interconnection case contemplates a new +/- 450 kV HVDC overhead line to transport 1,500 MW of power from the Keswick area of New Brunswick south via the northern Maine border to Millbury, Massachusetts.

This scenario would require the construction of approximately 400 circuit miles of new HVDC transmission in New England. An HVDC converter station near the Millbury substation would need to be constructed. (A transmission circuit and converter station also would need to be constructed in New Brunswick.)

The Québec interconnection case contemplates a new +/- 450 kV HVDC overhead line to transport 1,500 MW of power from the Des Cantons (Sherbrooke) area of Québec south via northern New Hampshire to Millbury, Massachusetts. This scenario would require the construction of approximately 280 circuit miles of new HVDC transmission in New England. An HVDC converter station near the Millbury substation would need to be constructed. (A transmission circuit and converter station also would need to be constructed in Québec.)

The U.S. portions of the New Brunswick and Québec interconnections are depicted in Figure 4.

Comparing Scenarios

The potential transmission configurations identified in this study, combined with varying levels of resource additions, allow for the comparison of multiple renewable resource scenarios for New England.

Transmission Cost Estimates

EIG developed preliminary order-of-magnitude cost-estimate ranges for the potential wind-expansion and interconnection-expansion configurations described above (see Appendix D).[23] The cost estimates provide a reasonable approximation, in 2009 dollars, of what the transmission networks for these cases might cost.

Table 6 summarizes the amount of new capacity and energy for each configuration, approximate circuit miles for potential transmission, and cost estimates, in 2009 dollars, for potential transmission. These "order-of-magnitude" cost estimates should not be considered firm construction-grade estimates.

[23] The scope of the ISO's analysis does not include funding mechanisms to support the potential transmission identified in the study.

Table 6
Wind Scenarios and Potential Transmission Configurations

Case	New Capacity (MW)	Percent of New England Energy	Approx. Circuit Miles of New Transmission	Preliminary Order-of-Magnitude Cost-Estimate Range by Voltage Class (billions of 2009 $)	Midrange Cost Estimate (billions of 2009 $)
New England Wind **1,000 MW inland; 1,000 MW offshore**	2,000	4.7	1,785	345 kV/HVDC: $4.7 to $7.9	$6.4
New England Wind **Offshore only**	2,000	5.1	1,015	345 kV/HVDC: $3.6 to $6.0	$4.8
New England Wind **2,000 MW inland; 2,000 MW offshore**	4,000	8.4	3,615	345 kV: $8.0 to $13.2 500 kV: $10.8 to $17.9	$10.7 $14.3
New England Wind **Offshore only**	4,000	9.3	1,430	345 kV/HVDC: $4.7 to $7.6	$6.1
New England Wind **1,500 MW inland (near the coast);** **4,000 MW offshore**	5,500	12.4	1,430	345 kV/HVDC: $4.7 to $7.6	$6.1
New England Wind **4,000 MW inland; 4,000 MW offshore**	8,000	15.9	4,320	500 kV: $13.4 to $22.4 765 kV: $17.3 to $28.9	$17.9 $23.0
New England Wind **7,500 MW inland; 4,500 MW offshore**	12,000	22.8	4,320	500 kV: $14.5 to $24.2 765 kV: $18.9 to $31.5	$19.3 $25.2
New Brunswick Interchange	1,500	10.7	400[a]	+/-450 kV HVDC: $1.5 to $2.5B[a]	$2.0B[a]
Québec Interchange	1,500	11.2	280[a]	+/-450 kV HVDC: $1.1 to $1.9[a]	$1.6B[a]
New England & Eastern Canadian Wind **5,500 MW New England *plus*** **3,000 MW New Brunswick & Québec**	8,500	14.7	2,110[a]	$4.7 to $7.6 New England Wind *plus* $2.6 to $4.4 New Brunswick & Québec Interchange[a] Total: ~$7 to ~$12	N/A
New England & Eastern Canadian Wind **12,000 MW New England *plus*** **3,000 MW New Brunswick & Québec**	15,000	26.1	5,000[a]	$14.5 - $31.5 New England Wind *plus* $2.6 to $4.4 New Brunswick & Québec Interchange[a] Total: ~$17 to ~$36	N/A

(a) Circuit miles and estimated costs are only for facilities located in New England.

Potential Wind Energy

The potential wind energy that could be achieved from several representative scenarios and the preliminary midrange cost estimates for the transmission that would be required to interconnect the different levels of resources is shown in Table 6.

The combined scenarios (e.g., 5,500 MW of New England wind; 8,500 MW of New England wind and imports from Eastern Canada; and 15,000 MW of New England wind and imports from Eastern Canada) are variations or modifications of the initial cases. For these modified scenarios, the ISO removed the load adders (i.e., PEVs and electric heat conversion).

Table 6 shows, for example, that New England could obtain approximately12% of its energy from wind power if 4,000 MW of offshore and 1,500 MW of inland wind resources were assumed to be developed in New England.

Study Results

The study measured economic and environmental metrics and generation by fuel type for each case. It produced thousands of data points, which are available in full on the ISO's Web site (see Appendix D).

The economic results are presented using average clearing prices, load-serving entity (LSE) expenses, and production cost metrics. The environmental results are presented using SO_2, NO_X, and CO_2 emissions metrics. The generation-by-fuel-type metric shows the amount of energy produced from natural gas, coal, wind, nuclear, demand resources, hydro, and other sources. The study also evaluated sensitivities for higher fuel prices and transmission constraints for each of these metrics.

The results show net energy market revenues for typical inland wind resources in central and northern New England and a typical combined-cycle natural-gas-fired generator (with a 7,300 Btu/kWh heat rate) for each case. The results also show the effect of higher fuel prices on these resources. As additional resources are added to the system, they put downward pressure on energy market prices, which reduce energy market revenues for resources. This in turn could affect the likelihood of generator retirements and the need for other revenue streams or subsidies for these hypothesized resources.

The economic results of this study are based on wholesale electric energy market revenues only and do not include the cost of transmission that may be needed to support the different cases. Transmission costs associated with each wind scenario and the new interconnections with neighboring areas are summarized in the above section.

Economic Metrics—Average Clearing Prices, LSE Energy Expenses, and Production Costs

The economic results of the study were evaluated by comparing the average annual clearing prices for each case to the base case. Figure 5 shows that prices tend to be lower than the base case when more efficient resources with lower marginal costs are added, or conversely, in cases that reduce the demand for electricity. Average annual clearing prices were calculated in dollars per megawatt-hour ($/MWh).

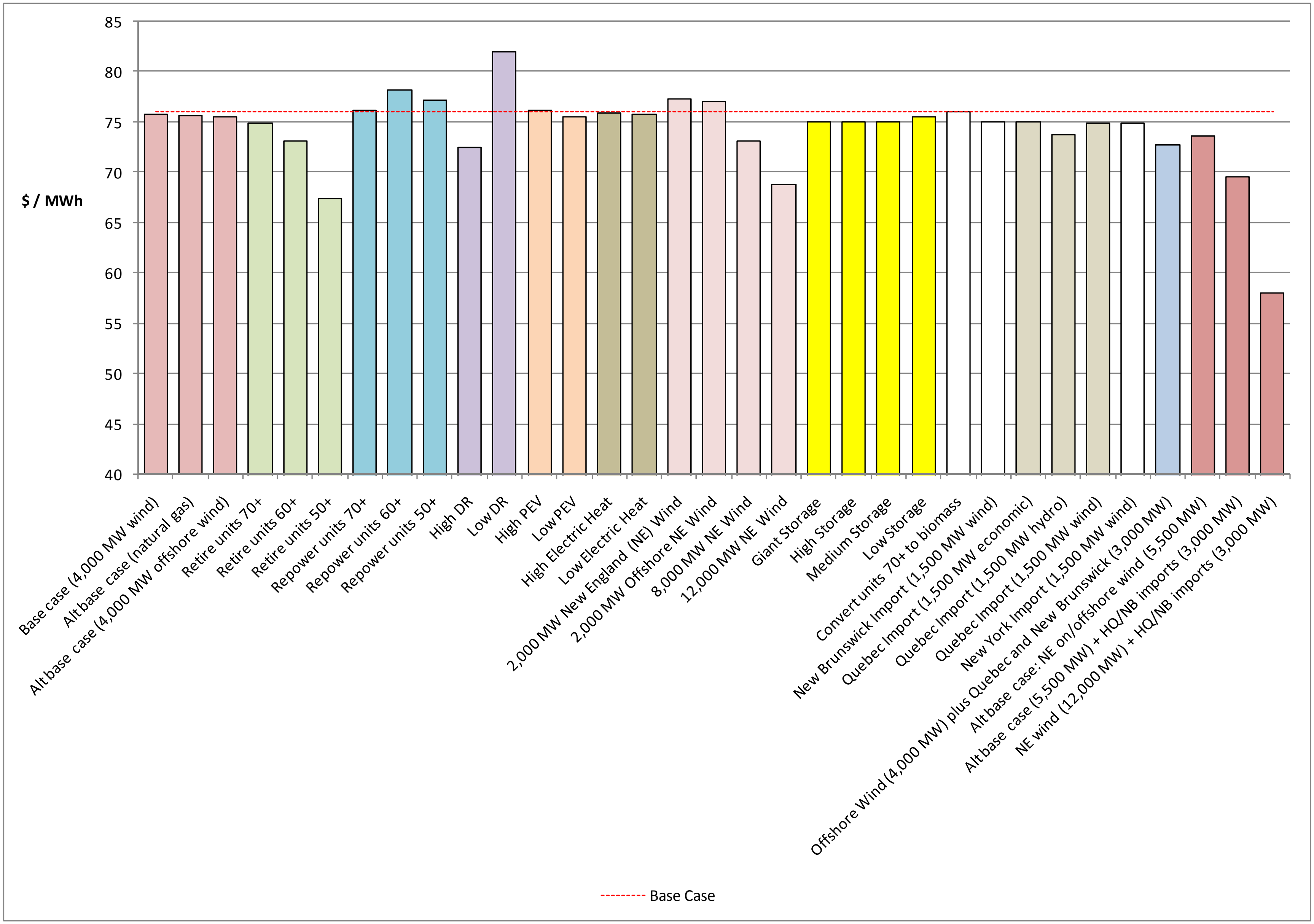

Figure 5: Average annual clearing prices.

The results showed that prices fall as older resources are retired and replaced with highly efficient resources with very low heat rates that are more efficient than today's typical marginal units. Prices increase in the repowering scenarios as older resources are repowered with more efficient resources with improved heat rates that, nevertheless, are not as efficient as today's typical marginal units.

The case with a high penetration of demand resources results in lower prices than the case with a lower penetration of demand resources and noticeably lower prices than the base case. A high penetration of PEVs and high electric heating conversion in Maine increases prices slightly because of the overall increase in the demand for electricity in this case.

The higher wind penetration cases reduce prices because more low-priced energy is added to the system.

The cases with more storage than the base case, which has no energy storage added beyond what currently exists in New England, result in slightly lower prices than the cases with less storage than the base case due to the increased use of off-peak energy. Each of the energy-storage cases results in lower prices than the base case.

Each of the import cases results in lower prices compared with the base case due to the addition of lower-priced energy into the system.

Figure 6 shows average annual clearing prices ($/MWh) for the modified scenarios described in Table 6. The results are shown for two sensitivities without transmission constraints (i.e., unconstrained). The first uses base fuel prices, and the second uses higher fuel prices. The figure shows electric energy prices for the scenarios that develop wind resources in New England and the scenarios that combine New England wind scenarios with new transmission to access wind and hydro resources in Québec and New Brunswick.

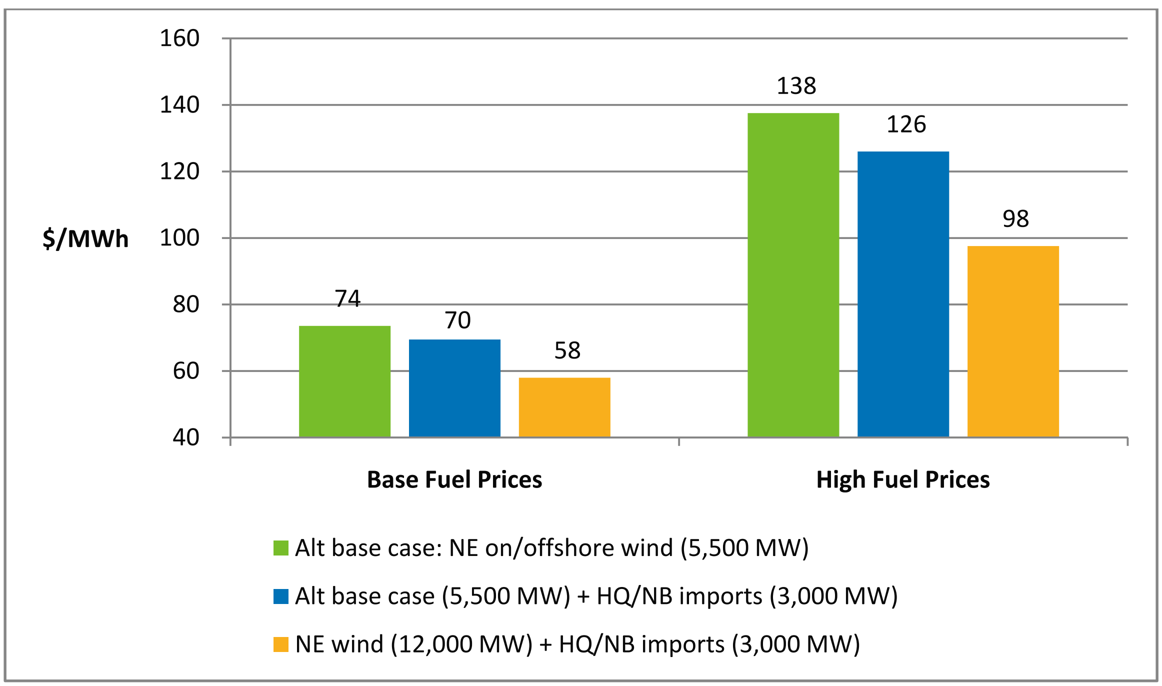

Figure 6: Average annual clearing prices—modified scenarios.

Table 7 shows annual LSE energy expenses, production costs, and average clearing prices with the base fuel prices and higher-fuel-price sensitivities for all cases. The LSE energy expenses and production costs are calculated on an annual basis in millions of 2007 dollars.

Table 7
Economic Metrics (Unconstrained)

Case	LSE Energy Expense ($ Million)	LSE Energy Expense High Fuel Price ($ Million)	Production Cost ($ Million)	Production Cost High Fuel Price ($ Million)	Avg. Clearing Prices ($/MWh)	Avg. Clearing Prices High Fuel Prices ($/MWh)
Base case (4,000 MW wind)	12,775	24,338	5,001	8,152	75.76	144.34
Alt. base case (natural gas)	12,747	24,308	5,836	9,769	75.60	144.16
Alt. base case (4,000 MW offshore wind)	12,720	24,238	4,884	7,928	75.44	143.74
Retire units 70+	12,618	24,050	5,013	8,407	74.83	142.63
Retire units 60+	12,318	23,510	5,188	9,349	73.05	139.43
Retire units 50+	11,358	21,642	4,984	9,005	67.36	128.35
Repower units 70+	12,839	24,468	5,104	8,571	76.14	145.11
Repower units 60+	13,170	25,133	5,526	9,962	78.11	149.06
Repower units 50+	12,997	24,816	5,516	9,947	77.08	147.17
High demand resources	12,224	23,237	4,084	6,396	72.49	137.81
Low demand resources	13,814	25,775	5,951	9,949	81.93	152.86
High PEV	13,052	24,871	5,201	8,536	76.16	145.13
Low PEV	12,520	23,837	4,804	7,774	75.50	143.75
High electric heat	12,844	24,472	5,051	8,247	75.87	144.55
Low electric heat	12,763	24,318	4,993	8,136	75.74	144.32
2,000 MW New England (NE) wind	13,033	24,764	5,470	9,051	77.29	146.87
2,000 MW offshore NE wind	12,991	24,706	5,411	8,937	77.05	146.52
8,000 MW NE wind	12,330	23,256	4,089	6,414	73.12	137.92
12,000 MW NE wind	11,597	21,030	3,315	5,022	68.78	124.72
Giant storage	12,634	24,127	5,039	8,225	74.93	143.09
High storage	12,634	24,127	5,039	8,224	74.93	143.09
Medium storage	12,653	24,160	5,034	8,215	75.04	143.28

Case	LSE Energy Expense ($ Million)	LSE Energy Expense High Fuel Price ($ Million)	Production Cost ($ Million)	Production Cost High Fuel Price ($ Million)	Avg. Clearing Prices ($/MWh)	Avg. Clearing Prices High Fuel Prices ($/MWh)
Low storage	12,725	24,259	5,012	8,172	75.47	143.87
Convert units 70+ to biomass	12,822	24,420	5,027	8,248	76.04	144.83
New Brunswick import (1,500 MW wind)	12,643	24,036	4,723	7,621	74.98	142.55
Québec import (1,500 MW economic)	12,636	23,692	4,993	7,667	74.94	140.51
Québec import (1,500 MW hydro)	12,423	23,672	4,385	6,971	73.67	140.39
Québec import (1,500 MW wind)	12,621	24,042	4,663	7,502	74.85	142.58
New York import (1,500 MW wind)	12,621	24,042	4,663	7,502	74.85	142.58
Offshore wind (4,000 MW) plus Québec and New Brunswick imports (3,000 MW)	12,256	23,265	3,998	6,231	72.69	137.98
Alt. base case: NE on/offshore wind (5,500 MW)	11,918	22,276	4,116	6,475	73.59	137.54
Alt. base case (5,500 MW) plus Québec and New Brunswick imports (3,000 MW)	11,255	20,406	3,310	4,991	69.50	126.00
NE wind (12,000 MW) plus Québec and New Brunswick imports (3,000 MW)	9,396	15,804	2,269	3,279	58.01	97.58

Environmental Metrics

Table 8 shows SO_2, NO_X, and CO_2 emissions for each case with and without the effect of transmission constraints. Except for the 12,000 MW wind scenario, the results show that transmission constraints do not have a significant effect on emissions. SO_2, NO_X, and CO_2 emissions are slightly higher in the 12,000 MW case with existing transmission constraints than without transmission constraints. Emissions are higher in the constrained scenario because the limitations on moving power around the region requires the ISO to dispatch less efficient resources, which generally are characterized by higher emissions. Table 9 shows SO_2, NO_X, and CO_2 emissions for each case with base fuel prices and the effect of higher fuel prices. NO_X emissions decrease slightly with higher fuel prices. CO_2 emissions fall slightly with higher fuel prices because of the incentive created to use the more fuel-efficient resources with lower emissions.

Table 8
Environmental Metric—Effect of Transmission Constraints

Case	Unconstrained Transmission			Existing Transmission Constraints			Difference		
	SO_2 (ktons)	NO_X (ktons)	CO_2 (mtons)	SO_2 (ktons)	NO_X (ktons)	CO_2 (mtons)	SO_2 (ktons)	NO_X (ktons)	CO_2 (mtons)
Base case (4,000 MW wind)	73.6	32.4	53.7	73.6	32.4	53.7	0.0	0.0	0.0
Alt. base case (natural gas)	73.6	32.7	58.9	73.6	32.7	58.9	0.0	0.0	0.0
Alt. base case (4,000 MW offshore wind)	73.6	32.3	53.0	73.6	32.3	53.0	0.0	0.0	0.0
Retire units 70+	35.8	28.7	50.1	35.8	28.6	50.1	0.0	(0.1)	0.0
Retire units 60+	2.9	19.2	41.1	2.9	19.0	41.0	0.0	(0.2)	-0.1
Retire units 50+	2.9	18.7	40.0	2.9	18.6	39.9	0.0	(0.1)	0.0
Repower units 70+	35.8	28.7	50.5	35.8	28.6	50.5	0.0	(0.1)	0.0
Repower units 60+	2.9	19.7	42.7	2.9	19.6	42.6	0.0	(0.1)	0.0
Repower units 50+	2.9	19.5	42.6	2.9	19.3	42.6	0.0	(0.2)	0.0
High demand resources	73.3	31.0	48.2	73.3	31.0	48.2	0.0	0.0	0.0
Low demand resources	74.7	34.1	59.3	74.6	34.1	59.3	(0.1)	0.0	0.0
High PEV	73.6	32.6	54.9	73.6	32.5	54.9	0.0	(0.1)	-0.1
Low PEV	73.6	32.4	52.5	73.6	32.3	52.5	0.0	(0.1)	0.0
High electric heat	73.6	32.5	54.0	73.6	32.4	54.0	0.0	(0.1)	0.0
Low electric heat	73.6	32.4	53.7	73.6	32.4	53.6	0.0	0.0	0.0
2,000 MW New England (NE) wind	73.6	32.8	56.5	73.6	32.8	56.5	0.0	0.0	0.0
2,000 MW offshore NE wind	73.6	32.7	56.1	73.6	32.7	56.1	0.0	0.0	0.0
8,000 MW NE wind	72.8	31.4	48.1	73.4	31.3	49.0	0.6	(0.1)	0.9
12,000 MW NE wind	66.9	29.3	42.2	72.5	30.8	45.8	5.6	1.5	3.6
Giant storage	73.6	32.1	54.0	73.6	31.9	53.9	0.0	(0.2)	0.0
High storage	73.6	32.1	54.0	73.6	32.0	53.9	0.0	(0.1)	0.0

Case	Unconstrained Transmission			Existing Transmission Constraints			Difference		
	SO_2 (ktons)	NO_X (ktons)	CO_2 (mtons)	SO_2 (ktons)	NO_X (ktons)	CO_2 (mtons)	SO_2 (ktons)	NO_X (ktons)	CO_2 (mtons)
Medium storage	73.6	32.1	54.0	73.6	31.9	53.9	0.0	(0.2)	0.0
Low storage	73.6	32.3	53.8	73.6	32.1	53.8	0.0	(0.2)	0.0
Convert units 70+ to biomass	67.6	31.7	53.1	67.6	31.6	53.0	0.0	(0.1)	0.0
New Brunswick import (1,500 MW wind)	73.3	32.1	52.0	73.6	32.0	52.7	0.3	(0.1)	0.7
Québec import (1,500 MW economic)	73.6	32.0	53.2	73.6	31.8	53.1	0.0	(0.2)	0.0
Québec import (1,500 MW hydro)	73.6	31.6	50.0	73.6	31.5	50.0	0.0	(0.1)	0.0
Québec import (1,500 MW wind)	73.6	32.0	51.7	73.6	31.8	51.7	0.0	(0.2)	0.0
New York import (1,500 MW wind)	73.6	32.0	51.7	73.6	31.8	51.7	0.0	(0.2)	0.0
Offshore wind (4,000 MW) plus Québec and New Brunswick imports (3,000 MW)	73.3	31.2	47.7	73.4	31.1	47.8	0.1	(0.1)	0.2
Alt. base case: NE on/offshore wind (5,500 MW)	72.4	31.6	48.2	72.6	31.5	48.2	0.2	(0.1)	0.0
Alt. base case (5,500 MW) plus Québec and New Brunswick imports (3,000 MW)	67.3	29.6	42.2	69.9	30.0	43.2	2.6	0.4	1.1
NE wind (12,000 MW) plus Québec and New Brunswick imports (3,000 MW)	50.7	23.6	31.8	62.1	27.5	37.7	11.4	3.9	5.9

Table 9
Environmental Metric—Effects of Transmission Constraints and Higher Fuel Prices

Case	Base Fuel Prices			Higher Fuel Prices			Difference		
	SO_2 (ktons)	NO_X (ktons)	CO_2 (Mtons)	SO_2 (ktons)	NO_X (ktons)	CO_2 (Mtons)	SO_2 (ktons)	NO_X (ktons)	CO_2 (Mtons)
Base case (4,000 MW wind)	73.6	32.4	53.7	73.6	32.1	51.7	0.0	(0.3)	(2.0)
Alt. base case (natural gas)	73.6	32.7	58.9	73.6	32.4	56.9	0.0	(0.3)	(2.0)
Alt. base case (4,000 MW offshore wind)	73.6	32.3	53.0	73.6	31.9	51.0	0.0	(0.4)	(2.0)
Retire units 70+	35.8	28.7	50.1	35.8	28.5	48.1	0.0	(0.2)	(2.1)
Retire units 60+	2.9	19.2	41.1	2.9	19.0	39.0	0.0	(0.2)	(2.1)
Retire units 50+	2.9	18.7	40.0	2.9	18.6	37.9	0.0	(0.1)	(2.1)
Repower units 70+	35.8	28.7	50.5	35.8	28.6	48.6	0.0	(0.1)	(2.0)
Repower units 60+	2.9	19.7	42.7	2.9	19.5	41.0	0.0	(0.2)	(1.7)
Repower units 50+	2.9	19.5	42.6	2.9	19.1	40.9	0.0	(0.4)	(1.7)
High demand resources	73.3	31.0	48.2	73.3	30.9	46.1	0.0	(0.1)	(2.2)
Low demand resources	74.7	34.1	59.3	74.6	33.9	57.5	-0.1	(0.2)	(1.8)
High PEV	73.6	32.6	54.9	73.6	32.4	53.0	0.0	(0.2)	(2.0)
Low PEV	73.6	32.4	52.5	73.6	31.9	50.5	0.0	(0.5)	(2.0)
High electric heat	73.6	32.5	54.0	73.6	32.2	52.0	0.0	(0.3)	(2.0)
Low electric heat	73.6	32.4	53.7	73.6	32.1	51.7	0.0	(0.3)	(2.0)
2,000 MW New England (NE) wind	73.6	32.8	56.5	73.7	32.7	54.6	0.1	(0.1)	(1.9)
2,000 MW offshore NE wind	73.6	32.7	56.1	73.6	32.7	54.2	0.0	0.0	(1.9)
8,000 MW NE wind	72.8	31.4	48.1	72.8	31.2	46.1	0.0	(0.2)	(2.1)
12,000 MW NE wind	66.9	29.3	42.2	66.9	29.1	40.4	0.0	(0.2)	(1.8)
Giant storage	73.6	32.1	54.0	73.6	31.8	52.0	0.0	(0.3)	(2.0)
High storage	73.6	32.1	54.0	73.6	31.8	52.0	0.0	(0.3)	(2.0)
Medium storage	73.6	32.1	54.0	73.6	31.8	51.9	0.0	(0.3)	(2.0)

Case	Base Fuel Prices			Higher Fuel Prices			Difference		
	SO_2 (ktons)	NO_X (ktons)	CO_2 (Mtons)	SO_2 (ktons)	NO_X (ktons)	CO_2 (Mtons)	SO_2 (ktons)	NO_X (ktons)	CO_2 (Mtons)
Low storage	73.6	32.3	53.8	73.6	31.9	51.8	0.0	(0.4)	(2.0)
Convert units 70+ to biomass	67.6	31.7	53.1	67.6	31.5	51.1	0.0	(0.2)	(2.0)
New Brunswick import (1,500 MW wind)	73.3	32.1	52.0	73.3	31.9	50.0	0.0	(0.2)	(2.0)
Québec import (1,500 MW economic)	73.6	32.0	53.2	73.6	31.5	47.8	0.0	(0.5)	(5.4)
Québec import (1,500 MW hydro)	73.6	31.6	50.0	73.6	31.4	47.9	0.0	(0.2)	(2.1)
Québec import (1,500 MW wind)	73.6	32.0	51.7	73.6	31.8	49.7	0.0	(0.2)	(2.1)
New York import (1,500 MW wind)	73.6	32.0	51.7	73.6	31.8	49.7	0.0	(0.2)	(2.1)
Offshore wind (4,000 MW) plus Québec and New Brunswick imports (3,000 MW)	73.3	31.2	47.7	73.3	31.1	45.5	0.0	(0.1)	(2.1)
Alt. base case: NE on/offshore wind (5,500 MW)	72.4	31.6	48.2	72.4	31.4	46.3	0.0	(0.2)	(1.9)
Alt. base case (5,500 MW) plus Québec and New Brunswick imports (3,000 MW)	67.3	29.6	42.2	67.3	29.5	40.4	0.0	(0.1)	(1.8)
NE wind (12,000 MW) plus Québec and New Brunswick imports (3,000 MW)	50.7	23.6	31.8	50.7	23.4	30.5	0.0	(0.2)	(1.2)

Figure 7 shows total annual CO_2 emissions for the modified scenarios as described in Table 6. The results are shown for two sensitivities without transmission constraints. The sensitivities are with and without higher fuel prices. Additional metrics for NO_X and SO_2 emissions are posted with the complete results on the ISO Web site (see Appendix D).

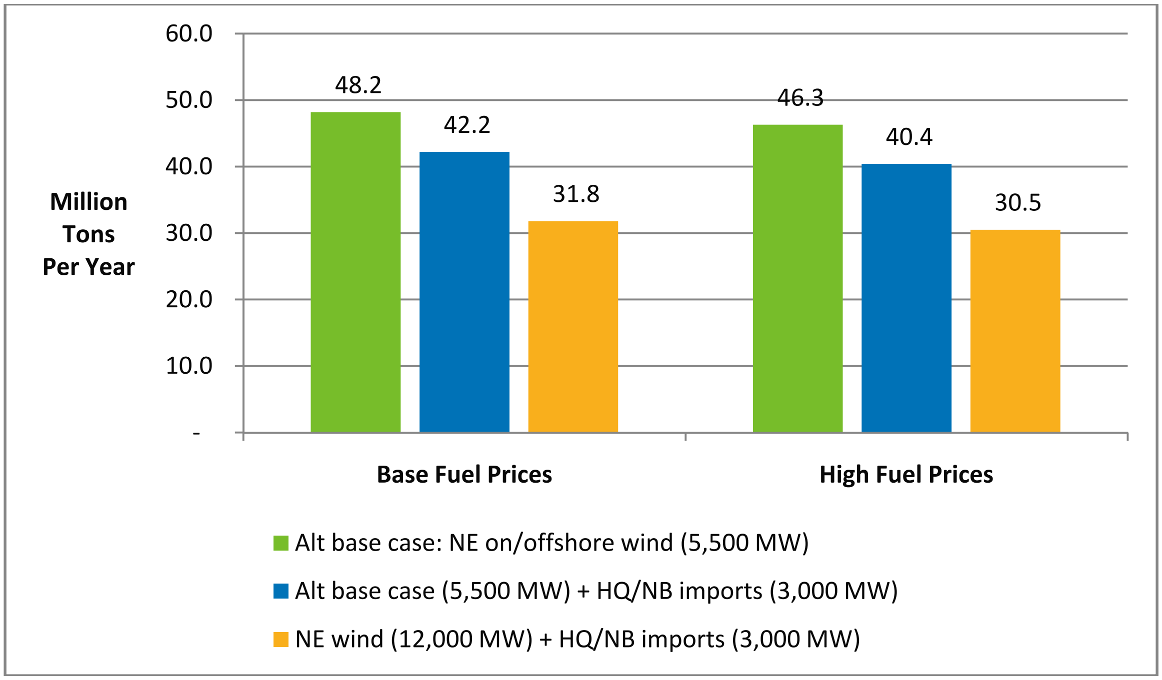

Figure 7: CO_2 emissions—modified scenarios.

Energy-by-Fuel-Type Metric

Figure 8 and Table 10 show the amount of electric energy and the percentage of total New England energy produced from natural gas, coal, wind, nuclear, demand resources, hydro, and other sources. These results assume no transmission constraints. The results allow comparisons of the relative amount of energy produced by different types of fuel for each scenario. For example, 8% of the region's electric energy would be derived from wind in the 4,000 MW scenario (base case), compared with 23% in the 12,000 MW wind scenario. (The energy percentages for each fuel type are similar in the higher-fuel-price sensitivity cases.) Figure 8 also shows that a high penetration of wind or demand resources reduces the amount of natural-gas-fired generation, whereas a low penetration of wind or demand resources increases the amount of gas-fired generation. Table 10 shows this information as a percentage of total New England energy.

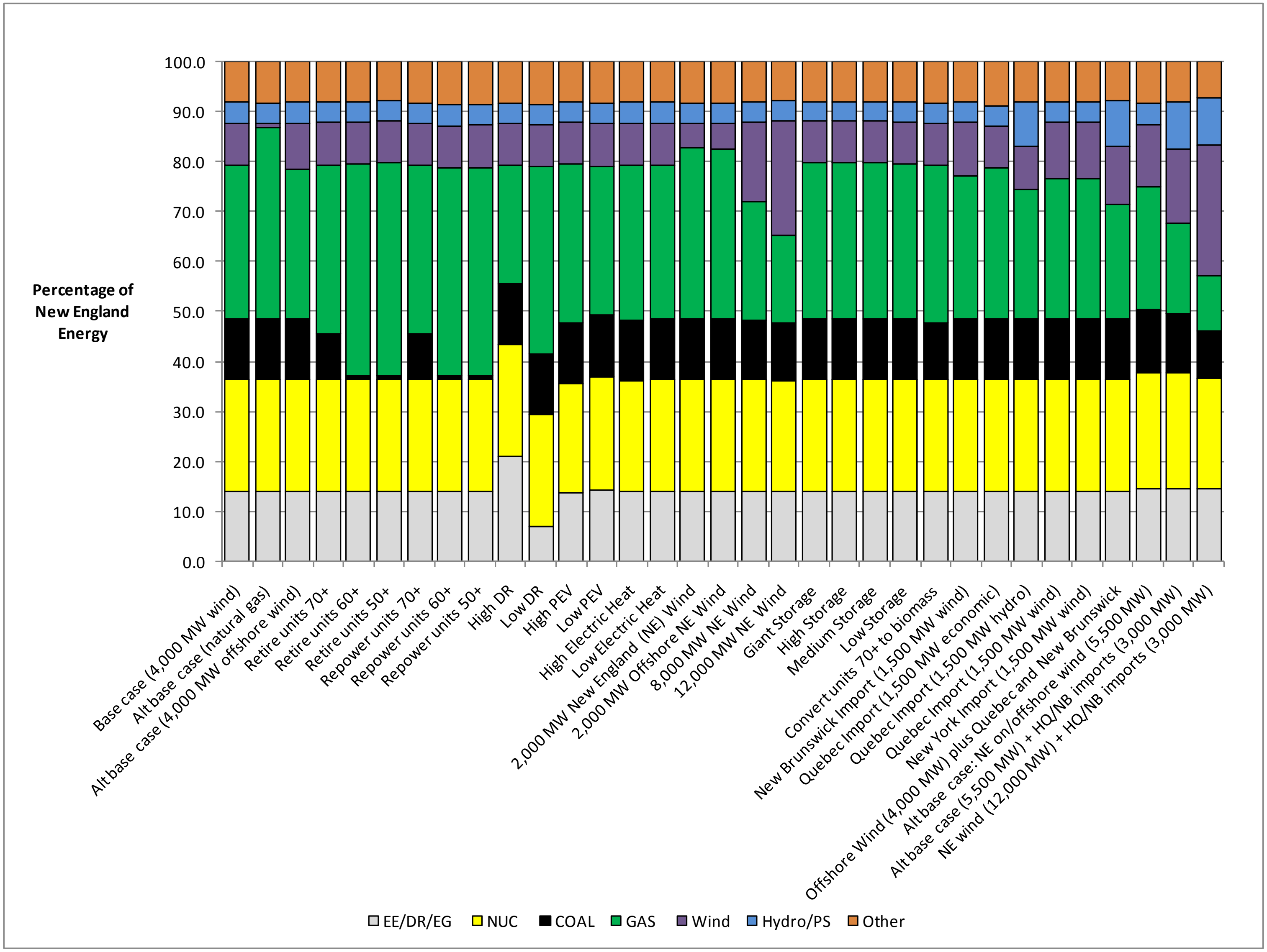

Figure 8: Energy by fuel type (unconstrained).

Note: "Other" includes residual fuel oil, municipal solid waste, wood/wood waste, landfill gas and other biomass gases, solar, and miscellaneous fuels.

Table 10
Percentage of Electric Energy by Fuel Type (Unconstrained)

Case	Total	Coal	Gas	Nuclear	Wind	EE/DR/EG	Hydro/PS	Other[(a)]
Base case (4,000 MW wind)	100	12.2	30.8	22.2	8.4	14.0	4.1	8.2
Alt base case (natural gas)	100	12.2	38.3	22.2	0.9	14.0	4.1	8.2
Alt base case (4,000 MW offshore wind)	100	12.2	29.9	22.2	9.3	14.0	4.1	8.2
Retire units 70+	100	9.3	33.7	22.2	8.4	14.0	4.1	8.1
Retire units 60+	100	0.9	42.3	22.2	8.4	14.0	4.1	8.0
Retire units 50+	100	0.9	42.5	22.2	8.4	14.0	4.1	7.8
Repower units 70+	100	9.3	33.5	22.2	8.4	14.0	4.1	8.3
Repower units 60+	100	0.9	41.6	22.2	8.4	14.0	4.1	8.7
Repower units 50+	100	0.9	41.7	22.2	8.4	14.0	4.1	8.6
High demand resources	100	12.2	23.7	22.2	8.4	21.1	4.1	8.3
Low demand resources	100	12.2	37.5	22.2	8.4	7.0	4.1	8.5
High PEV	100	12.0	31.9	21.9	8.3	13.8	4.1	8.1
Low PEV	100	12.4	29.7	22.6	8.6	14.3	4.2	8.3
High electric heat	100	12.1	31.1	22.2	8.4	14.0	4.1	8.2
Low electric heat	100	12.2	30.8	22.3	8.4	14.0	4.1	8.2
2,000 MW New England (NE) wind	100	12.2	34.4	22.2	4.7	14.0	4.1	8.4
2,000 MW offshore NE wind	100	12.2	34.0	22.2	5.1	14.0	4.1	8.3
8,000 MW NE wind	100	12.1	23.6	22.2	15.9	14.0	4.1	8.0
12,000 MW NE wind	100	11.4	17.7	22.2	22.8	14.0	4.1	7.8
Giant storage	100	12.2	31.3	22.2	8.4	14.0	3.7	8.2
High storage	100	12.2	31.3	22.2	8.4	14.0	3.7	8.2
Medium storage	100	12.2	31.3	22.2	8.4	14.0	3.7	8.2
Low storage	100	12.2	31.0	22.2	8.4	14.0	4.0	8.2

Case	Total	Coal	Gas	Nuclear	Wind	EE/DR/EG	Hydro/PS	Other[(a)]
Convert units 70+ to biomass	100	11.6	31.4	22.2	8.4	14.0	4.1	8.2
New Brunswick import (1,500 MW wind)	100	12.2	28.6	22.2	10.7	14.0	4.1	8.1
Québec import (1,500 MW economic)	100	12.2	30.2	22.2	8.4	14.0	4.1	8.8
Québec import (1,500 MW hydro)	100	12.2	26.1	22.2	8.4	14.0	9.1	8.0
Québec import (1,500 MW wind)	100	12.2	28.1	22.2	11.2	14.0	4.1	8.1
New York import (1,500 MW wind)	100	12.2	28.1	22.2	11.2	14.0	4.1	8.1
Offshore wind (4,000 MW) plus Québec and New Brunswick imports (3,000 MW)	100.0	12.2	22.9	22.2	11.6	14.0	9.1	7.9
Alt. base case: NE on/offshore wind (5,500 MW)	100.0	12.6	24.6	23.2	12.4	14.6	4.3	8.4
Alt. base case (5,500 MW) plus Québec and New Brunswick imports (3,000 MW)	100.0	12.0	18.0	23.1	14.7	14.6	9.4	8.1
NE wind (12,000 MW) plus Québec and New Brunswick imports (3,000 MW)	100.0	9.4	11.2	22.0	26.1	14.6	9.4	7.3

(a) "Other" includes residual fuel oil, municipal solid waste, wood/wood waste, landfill gas and other biomass gases, solar, and miscellaneous fuels.

Table 11 shows the amount of energy (as a percentage of the total for New England) by fuel type for the modified cases. These results assume no transmission constraints.

Table 11
Percentage of Electric Energy Provided in Modified Scenarios, by Fuel Type

Modified Scenarios	Coal	Gas	Nuclear	Wind	EE/DR/EG	Hydro/PS	Other (a)
Base case with 5,500 MW wind 4,000 MW offshore *plus* 1,500 MW inland (near the coast)	13%	25%	23%	12%	15%	4%	8%
Base case with 5,500 MW wind *plus* **3,000 MW Québec** **and New Brunswick Interchange**	12%	18%	23%	15%	15%	9%	8%
12,000 MW wind case *plus* **3,000 MW Québec** **and New Brunswick Interchange**	9%	11%	22%	26%	15%	9%	7%

(a) "Other" includes residual fuel oil, municipal solid waste, wood/wood waste, landfill gas and other biomass gases, solar, and miscellaneous fuels.

Economic Viability of Resources

The results show that adding resources to the system puts downward pressure on energy market clearing prices. Even the most efficient resources (e.g., an advanced combined-cycle natural-gas-fired generator) would be challenged to continue operating based on the economic results of this study. For some resources, the reduction in energy market revenues could result in generator retirements.

Figure 9 to Figure 12 show the revenues from an inland wind resource and a typical combined-cycle resource. Figure 9 shows the contributions toward fixed costs that an inland wind resource could earn in the energy market ($/kW-year), assuming the transmission system is unconstrained. Figure 10 shows the contributions toward fixed costs that an inland wind resource could earn in the energy market for the high-fuel-price sensitivity. Figure 11 shows the contributions toward fixed costs that a typical 7,300 Btu/kWh natural-gas-fired combined-cycle generator could earn in the energy market for each case, and Figure 12 shows the contributions toward fixed costs that this type of generator could earn for each case in the high-fuel-price sensitivity.

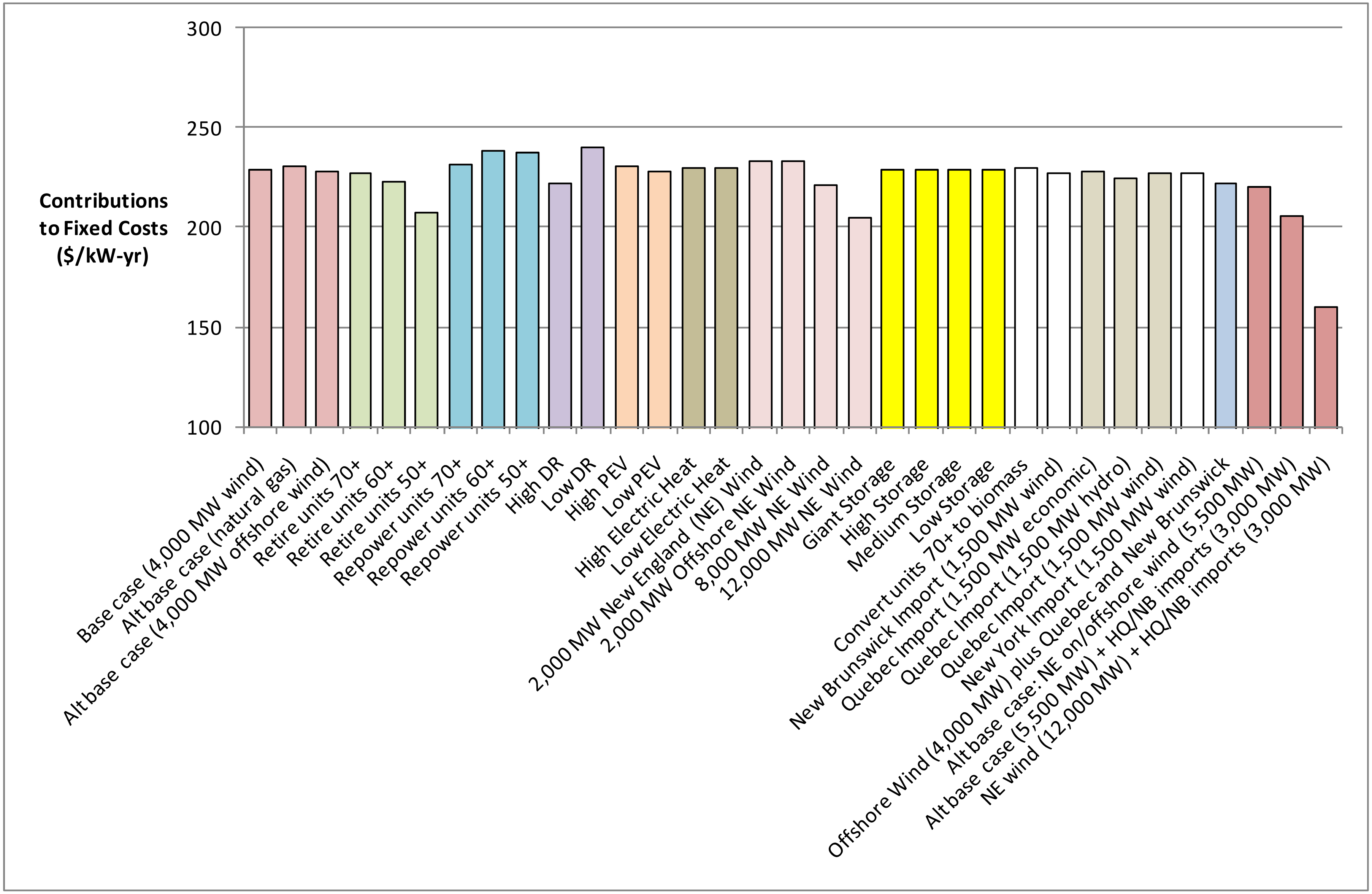

Figure 9: Representative revenues from the energy market for an inland wind resource.

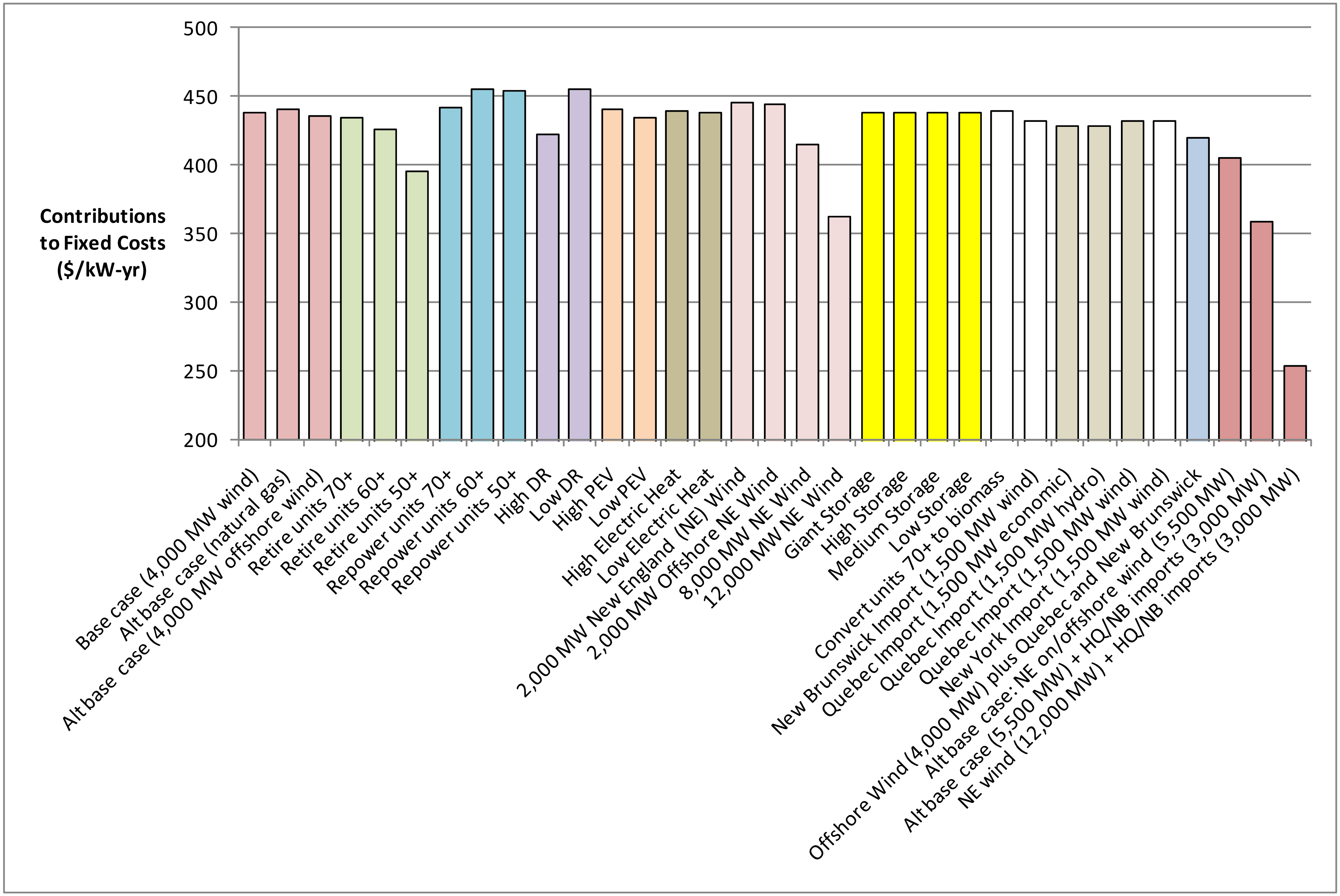

Figure 10: Representative revenues from the energy market for an inland wind resource (higher fuel prices).

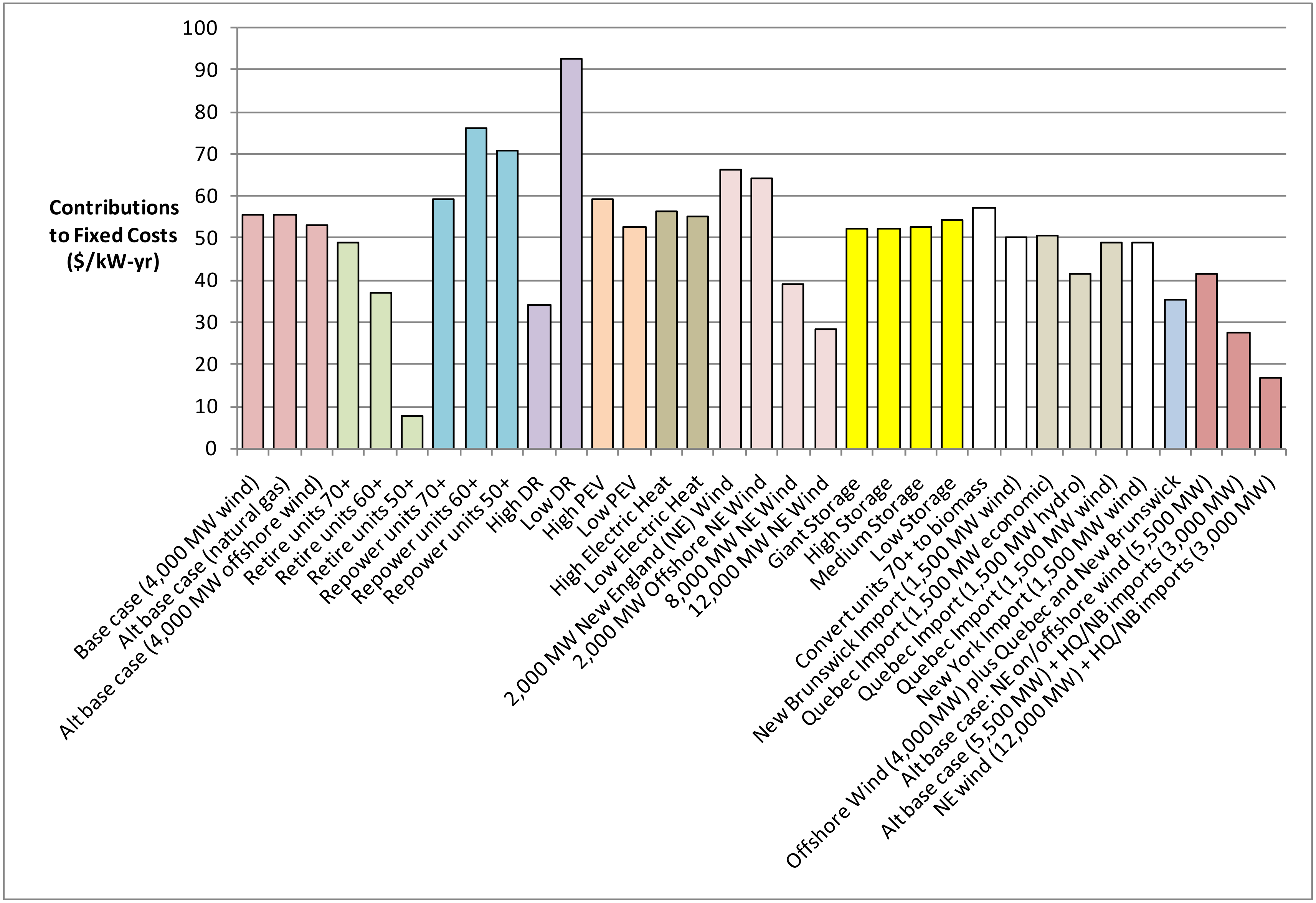

Figure 11: Representative revenues from the energy market for a typical combined-cycle resource.

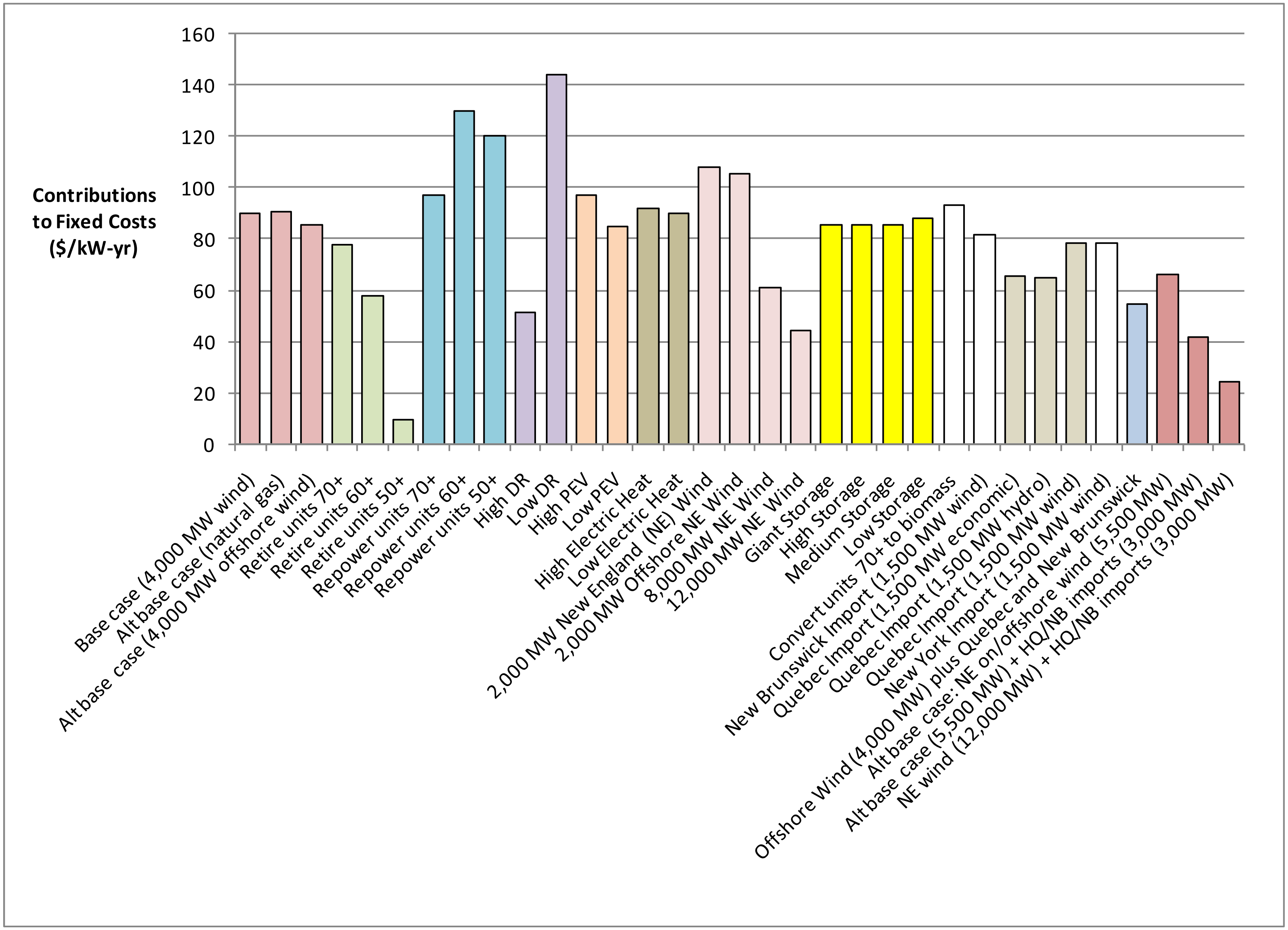

Figure 12: Representative revenues from the energy market for typical combined-cycle resource (higher fuel prices).

Effect of Transmission Constraints

Much of the analysis in this study assumed that the transmission system would expand significantly. To provide a more complete perspective, the analysis considered the effect of transmission constraints remaining within New England after the New England East–West Solution (NEEWS) and Maine Power Reliability Project (MPRP) are completed. It had been assumed that transmission would be sufficient to bring the case-specific external resources into New England (i.e., import scenarios) but that existing transmission within New England could impede the flow of energy from where it is produced to the load centers where it is consumed. Unlike the assumption of significant transmission expansion, the effect of these transmission constraints on the contributions to fixed costs will be influenced by other flows to, and from, external areas. For example, other imports from New Brunswick into New England could exacerbate congestion on the transmission system for energy flows from north to south.

Figure 9 and Figure 10 show the "contributions toward fixed costs" that an inland wind resource could earn in the energy market. Without the effect of transmission constraints, these values would apply to all wind resources that have the same assumed wind profile, regardless of where that resource was located. With transmission constraints, the value would be lower in areas of New England where transmission impeded the flow of energy.

Figure 13 shows the contributions toward fixed costs that a wind resource in northern New England could earn in the energy market if transmission were sufficient to eliminate transmission constraints. Figure 14 shows the resulting contributions toward fixed costs that the same resource in northern New England could earn in the energy market if no additional transmission expansion were included. Figure 15 shows that transmission constraints would reduce the value from wind, as well as other technology resources in northern New England, by approximately $60/kW-year in most of the cases. This is a reduction of approximately 30% from the comparable values shown in Figure 9.

In the cases with less wind located in northern New England, such as the 2,000 MW case, or more wind resources located offshore, the effect of congestion is much less. In the cases with imports from New Brunswick or higher penetrations of wind, the contributions to fixed costs are more greatly reduced as congestion increases.

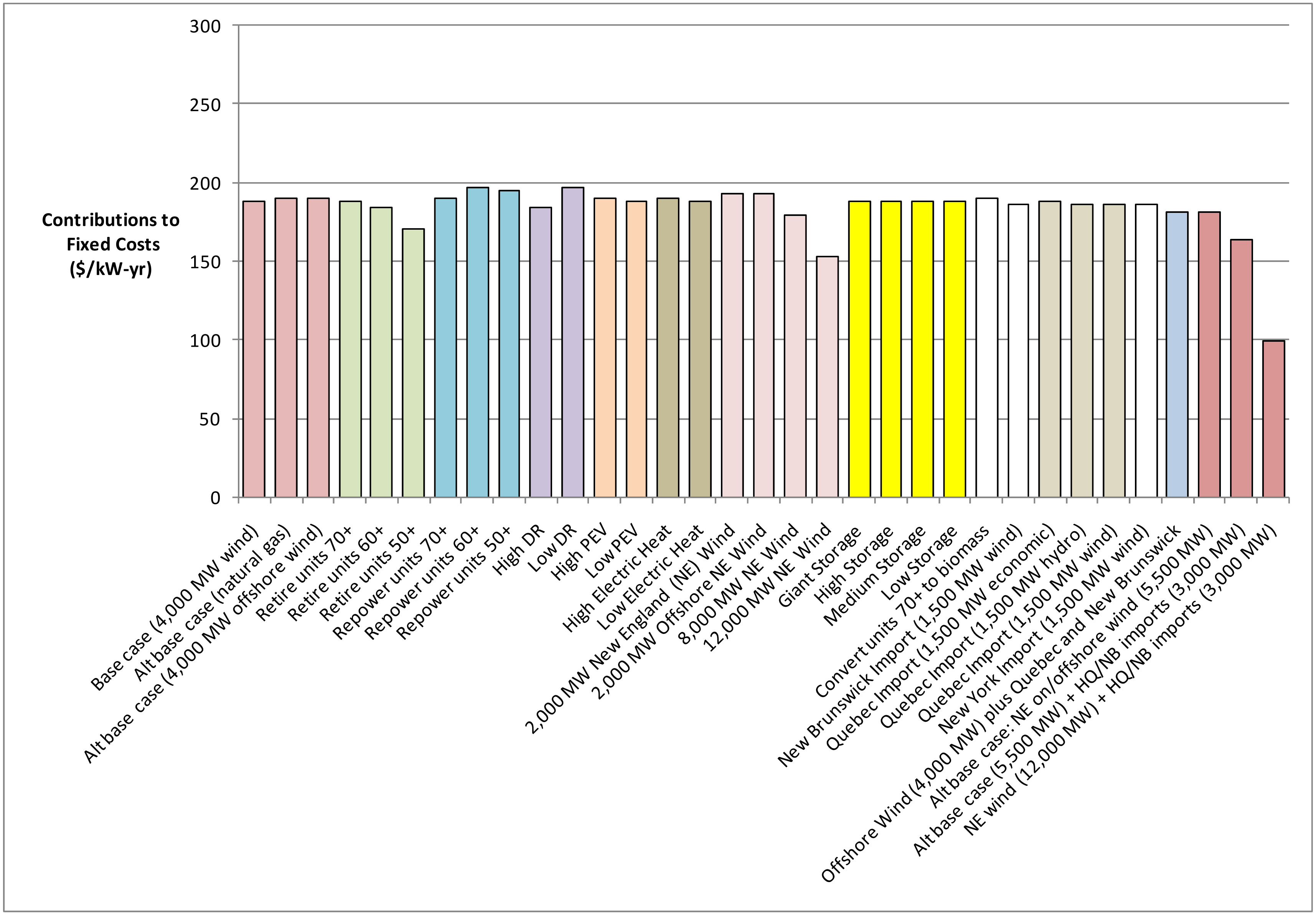

Figure 13: Contributions to fixed costs in northern New England <u>without</u> transmission constraints.

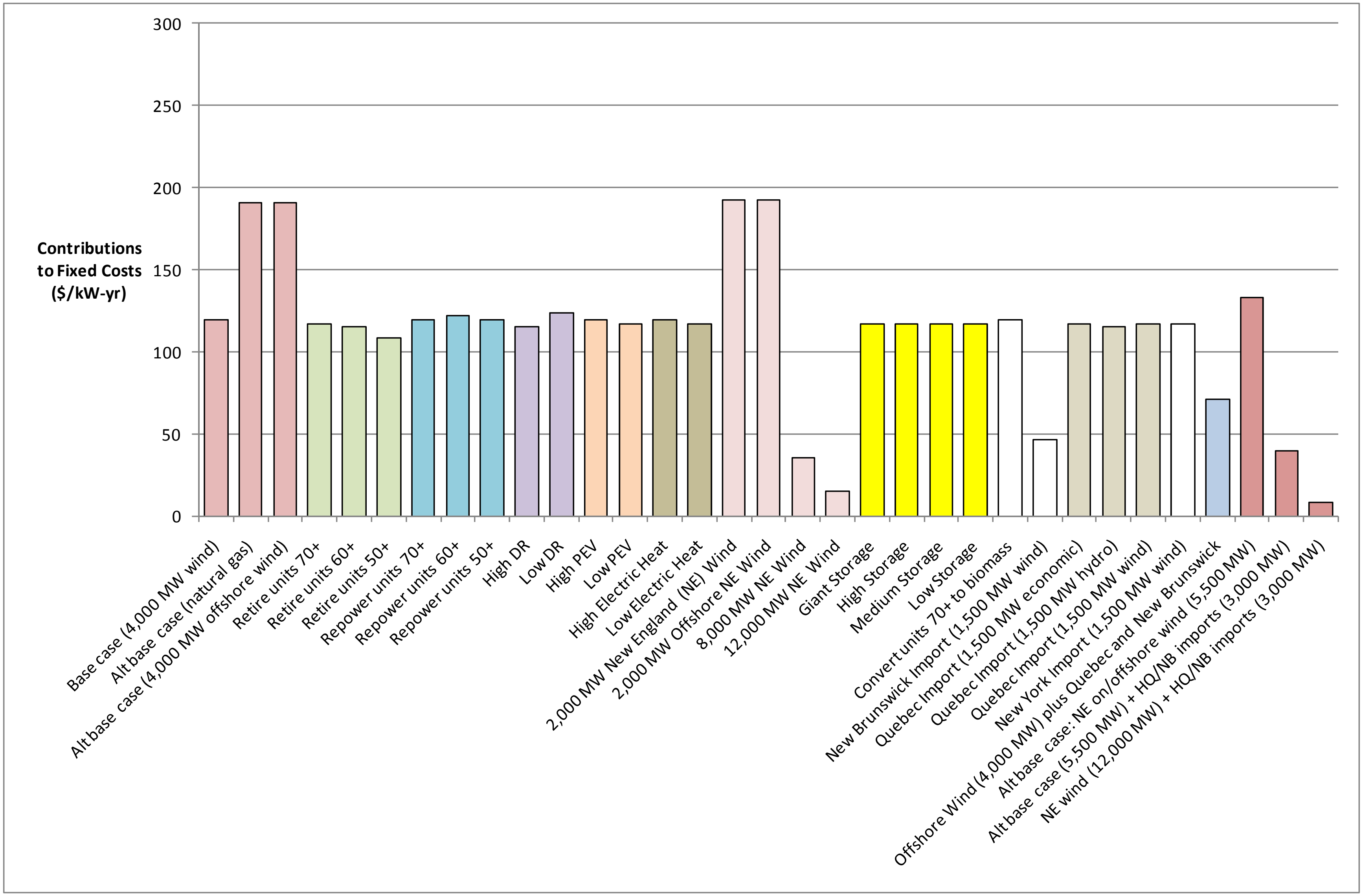

Figure 14: Contributions to fixed costs in northern New England <u>with</u> transmission constraints.

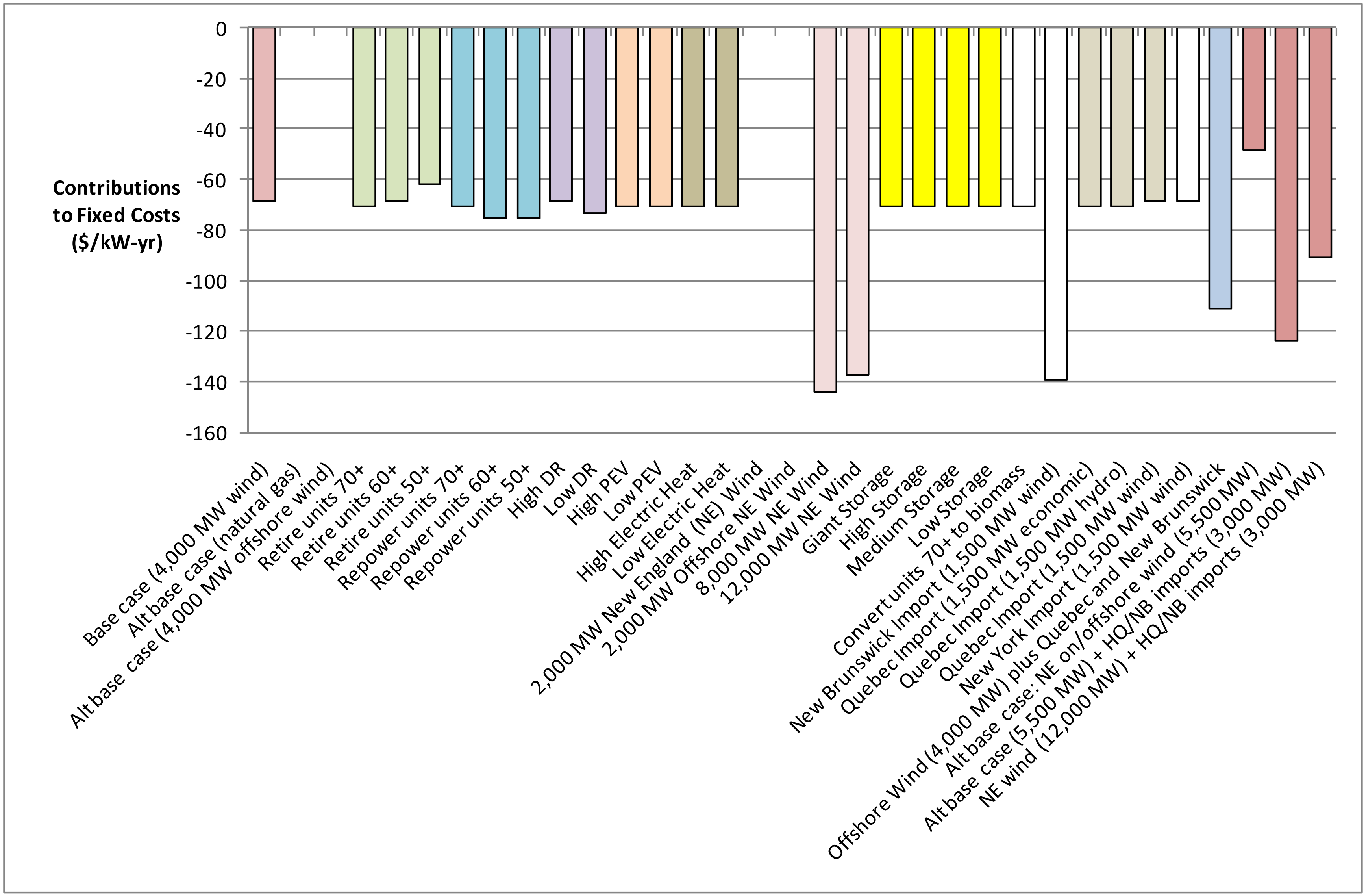

Figure 15: Representative revenues from the energy market for a typical northern New England resource with effects of transmission constraints.

Highlights of Study Results

A vast number of comparisons are possible for the more than 100 cases and sensitivities modeled in this study. The following are highlights of the study results. These results assume the completion of the transmission projects in RSP09 and the transmission expansion contemplated in the study, which would largely eliminate transmission constraints.

- Economic metrics:

  The following economic metrics are based on wholesale energy market revenues alone and do not include the cost of transmission that may be required to support the various scenarios. In addition, ancillary service costs may increase, and these are the subject of the ISO's ongoing Wind Integration Study.

  - **Average Annual Clearing Prices**—The average annual clearing prices are relatively constant across the scenarios. Average clearing prices fall within a range of $67/MWh to $82/MWh. The base case value is $76/MWh. The annual clearing price is generally higher in cases that have higher loads, such as high penetration of PEVs; the clearing price is generally lower in cases that add electric energy to (or remove energy from) the system, such as the cases with higher wind penetration or higher demand-resource penetration. Cases that retire large amounts of fossil fuel generators and replace these resources with the most efficient advanced combined-cycle natural-gas-fired generators tend to produce lower clearing prices.

  - **Economic Viability of Resources**—The study evaluates only net energy market revenues for the different cases, thus the evaluation of other sources of revenue, such as for capacity payments, ancillary services, or RECs, is beyond the scope of this study. The study shows a similar trend in electric energy market revenues for a typical inland wind resource and a typical natural-gas-fired combined-cycle resource—revenues are lower in cases where resources with lower marginal costs are added to the system (i.e., the high wind cases). This results in paying lower energy prices to all resources, which could lead to some generator retirements and a need for additional resources. Other sources of revenue may need to be considered to ensure the economic viability of resources.

  - **Load**—The gross annual load levels are relatively constant across scenarios, except for the high PEV penetration case in which loads are slightly higher. The combination of load modifiers including existing hydro, pumped storage, and wind resources reduces system load needed to be served by fossil and nuclear resources from a peak of 34,500 MW to approximately 22,000 MW.

  - **LSE Energy Expense**—Total annual load-serving entity energy expenses do not vary significantly across the scenarios for a given fuel-price outlook. Fuel prices, especially natural gas, have a significant impact on LSE energy expenses. LSE energy expenses fall within a range of $11,358 million to $13,814 million. The base case LSE energy expense value is $12,775 million.

  - **Production Costs**—The annual production cost expenses fall within a range of $3,315 million to $5,951 million. The base case production cost value is $5,000 million.

  - **Electricity Substitution for Other Fuels**—In the cases for PEVs and increased electric heating in Maine, this study does not try to account for the corresponding reduction in energy costs for transportation fuels or heating oil.

- Environmental metrics:
    - **Largest Emissions Reductions**—The retirement and repowering scenarios produce the lowest emissions of sulfur dioxide, nitrogen oxide, and carbon dioxide. The higher wind penetration scenarios also produce significant reductions in SO_2, NO_X, and CO_2.
    - **Transmission Constraints**—Modeling the system with transmission constraints does not produce noticeably different results for SO_2, NO_X, and CO_2 emissions, except that SO_2, NO_X, and CO_2 emissions are higher in the 12,000 MW wind case when existing transmission constraints are modeled.
    - **Sulfur Dioxide Emissions**—Sulfur dioxide emissions vary significantly across the scenarios. SO_2 emissions fall within a range of 3 to 75 ktons. The most aggressive generator retirement cases result in the lowest SO_2 emissions, and the cases with low demand-resource penetration result in the highest SO_2 emissions. The base case value is 74 ktons.
    - **Nitrogen Oxide Emissions**—Nitrogen oxide emissions do not vary significantly across the scenarios. NO_X emissions fall within a range of 19 to 34 ktons. The most aggressive generator retirement cases result in the lowest NO_X emissions, especially as coal units are retired. The cases with low demand-resource penetration result in the highest NO_X emissions. The base case value is 32 ktons.
    - **Carbon Dioxide Emissions**—Carbon dioxide emissions vary notably across the scenarios. CO_2 emissions fall within a range of 40 to 59 mtons. The most aggressive generator retirement cases result in the lowest CO_2 emissions, and the cases with low demand-resource penetration result in the highest CO_2 emissions. The base case value is 54 mtons.
    - **Higher Fuel Prices—**SO_2, NO_X, and CO_2 emissions are not significantly affected by higher fuel prices.
- Energy by fuel type:
    - **Wind**—The 12,000 MW wind case provides the highest levels of electric energy from wind resources. The alternative natural gas base case produces the lowest amount of energy from wind.
    - **Natural gas**—The higher New England wind cases produce the lowest amount of electric energy from natural gas. The alternative natural gas base case and the retirement and repowering scenarios produce the highest amount of energy from natural gas.
    - **Coal**—The retirement and repowering scenarios produce the lowest amount of electric energy from coal.
    - **Nuclear**—The electric energy produced by nuclear plants is constant across the cases.
    - **Demand Resources**—The energy produced by demand resources (energy efficiency, demand response, and emergency generation) is relatively constant across the cases; it is higher in the case with higher demand-resource penetration and lower in the case with lower demand-resource penetration.
    - **Hydro/Pumped Storage**—The electric energy from hydro/pumped storage is relatively constant across the scenarios; it more than doubles in the case with 1,500 MW of increased import capability from Québec, which assumes that most new energy from Québec is produced by hydro resources.

- **Plug-in Electric Vehicles**—PEVs would increase off-peak electricity demand, assuming customers charge PEVs during off-peak hours. PEVs could add approximately 5,000 MW of off-peak load, assuming high penetration.

- **Energy Storage**—The opportunities to use energy storage are limited because of the use of large amounts of peak-shaving demand resources assumed in the study. The study examined only daily energy storage; longer term (i.e., weekly or seasonal storage) could provide additional benefits.

- **Maine Electric Heating Conversion**—The Maine electric heating conversion case, which displaces oil heating for electric heating, increases the use of natural gas to produce electricity. (Other cases that add wind to the system displace the marginal resource on the electric power system, which typically is natural gas. The analysis was not designed to explicitly evaluate wind as a direct substitute for home heating oil.)

Possible Resource Combinations

Three possible renewable resource combinations were reviewed to bracket a range of possible outcomes based on the level of potential transmission investment to support renewable resource integration across New England. These cases, which assessed 5,500 MW; 8,500 MW; and 15,000 MW of various combinations of added renewables, identify potential scenarios for New England to not only satisfy state and possible federal renewable energy policies but also to become a supplier of renewable energy to the broader Eastern Interconnection.

Conclusions

ISO New England is pleased to provide the results of this economic study in support of the New England governors' initiative to develop a regional energy blueprint. The results of this scenario analysis clearly demonstrate that New England has significant potential for developing renewable sources of energy within the region—primarily from inland and offshore wind resources—and significant potential to expand energy trade with neighboring regions. The ISO looks forward to further discussions with the states and regional stakeholders on the information and analysis contained in this report.

Appendix A
List of Cases

Case Name	Description
Base Cases	
Base case (4,000 MW wind)	One year only (2030) All resources in service with no retirements Passive demand resources (EE): 3,450 MW Active demand resources: 3,100 MW Real-time emergency generation: 800 MW Assume medium PEV penetration of 2/3 of Oak Ridge's 2.5 million estimate with a 2 kW power-interface connector Base Maine conversion from oil to electric heat Wind penetration of 4,000 MW (2,000 inland; 2,000 offshore)
Alt. base case (natural gas)	Same as base case except add 1,500 MW of new efficient natural gas combined-cycle (CC) units in place of 4,000 MW of wind to emulate the energy from wind in the base case
Alt. base case (4,000 MW offshore wind)	Same as the base case except the 4,000 MW of wind was all assumed to be offshore
Retirement Cases	
Retire units 70+	Same as base case except 1,000 MW of units older than 70 years assumed to be retired and replaced with an equal amount of new efficient gas CC (1,217 MW)
Retire units 60+	Same as base case except 4,000 MW of units older than 60 years assumed to be retired and replaced with an equal amount of new efficient gas CC (4,347 MW)
Retire units 50+	Same as base case except ~9,000 MW of units older than 50 years assumed to be retired and replaced with an equal amount of new efficient gas CC (8,610 MW)
Repowering Cases	
Repower units 70+	Same as base case except 1,000 MW of units older than 70 years assumed to be retired and replaced with a repowering that is natural-gas fueled and less efficient than a new gas CC (1,217 MW)
Repower units 60+	Same as base case except 4,000 MW of units older than 60 years assumed to be retired and replaced with a repowering that is natural-gas fueled and is less efficient than a new gas CC (4,347 MW)
Repower units 50+	Same as base case except ~9,000 MW of units older than 50 years assumed to be retired and replaced with a repowering that is natural-gas fueled and less efficient than a new gas CC (8,610 MW)
Demand-Resource Cases	

Case Name	Description
High demand resources	Same as the base case except higher demand resources Passive demand resources (EE) of 5,175 MW Active demand resources of 4,400 MW RTEG of 800 MW
Low demand resources	Same as the base case except lower demand resources Passive demand resources (EE) of 1,725 MW Active demand resources of 1,650 MW RTEG of 800 MW
Plug-in Electric Vehicle Cases	
High PEV	Same as the base case except using 100% of Oak Ridge's PEV penetration estimate of 2.5 million by 2030
Low PEV	Same as the base case except using 1/3 of Oak Ridge's PEV penetration estimate of 2.5 million
Maine Electric Heat Cases	
High electric heat	Same as the base case except higher Maine conversion from oil to electric heat
Low electric heat	Same as the base case except lower Maine conversion from oil to electric heat
New England Wind Cases	
2,000 MW New England (NE) wind	Same as the base case except wind penetration of 2,000 MW (1,000 inland; 1,000 offshore)
2,000 MW offshore NE wind	Same as the base case except wind penetration of 2,000 MW, all located offshore
8,000 MW NE wind	Same as the base case except wind penetration of 8,000 MW (4,000 inland; 4,000 offshore)
12,000 MW NE wind	Same as the base case except wind penetration of 12,000 MW (8,000 inland; 4,000 offshore)
Storage Cases	
Giant storage	Same as the base case, except 5,000 MW of new storage is discharged/recharged daily (20% of 2.5 million PEV at 10 kW, each able to peak shift).
High storage	Same as the base case. except 3,000 MW of new storage is discharged/recharged daily
Medium storage	Same as the base case except, 2,000 MW of new storage is discharged/recharged daily
Low storage	Same as the base case, except 1,000 MW of new storage is discharged/recharged daily
Biomass Conversion Case	
Convert units 70+ to biomass	Convert units over 70 years old to burn biomass based on unit size constraints

Case Name	Description
Import Cases	
New Brunswick import (1,500 MW wind)	Same as the base case except 1,500 MW of wind would be from NB
Québec import (1,500 MW economic)	Same as the base case except for an additional 1,500 MW of hydro-based imports (modeled like current HQ economic imports)
Québec import (1,500 MW hydro)	Same as the base case except 1,500 MW of HQ interconnection hydro would have a 63.4% capacity factor
Québec import (1,500 MW wind)	Same as the base case except for an additional 1,500 MW of wind profile imports
New York import (1,500 MW wind)	Import 1,500 MW of wind from New York due to increased interconnections with New York
Offshore wind (4,000 MW) plus Québec and New Brunswick imports (3,000 MW)	Same as the alternate base case except 1,500 MW of HQ interconnection hydro would have a 63.4% capacity factor, plus 1,500 MW of wind would be from New Brunswick. New England has 4,000 MW of offshore wind
Modified Scenarios	
Alternate base case: NE on/offshore wind (5,500 MW)	**5,500 MW**: Modify case 1 (base case): Model all 4,000 MW of wind as offshore; Add 750 MW in northeastern New England plus 750 MW (allocated 50/50) to Rhode Island and Southeastern Massachusetts
Alternate base case (5,500 MW) + HQ/NB imports (3,000 MW)	**8,500 MW**: Modify 5,500 MW alternate base case: Add 1,500 MW of hydro from Québec (with a 63% capacity factor), plus 1,500 MW of wind from New Brunswick (northeastern New England wind profile at 30% capacity factor)
NE wind (12,000 MW) + HQ/NB imports (3,000 MW)	**15,000 MW**: Modify case 16 (12,000 MW wind case): Assuming the 12,000 MW inland/offshore wind expansion, add 1,500 MW of hydro at a 63% capacity factor from Québec plus 1,500 MW of wind in New Brunswick (northeastern New England wind profile at 30% capacity factor)
Midwest Coal/Wind plus New England Wind (Inland and Offshore)	
Midwest coal (9,600 MW) + NE wind (4,000 MW)	Inject 9,600 MW of Midwest resources into Norwalk, assuming 9.600 MW of "coal" capacity. New England has 2,000 MW of inland and 2,000 MW of offshore wind.
Midwest coal/wind (9,600 MW) + NE wind (4,000 MW)	Inject 9,600 MW of Midwest wind and coal into Norwalk, assuming 4,800 MW of "coal" capacity and 4,800 MW of "inland" wind profile energy. New England has 2,000 MW of inland and 2,000 MW of offshore wind.
Midwest wind (9,600 MW) + NE wind (4,000 MW)	Inject 9,600 MW of Midwest resources into Norwalk by assuming 9,600 MW of "inland" wind profile energy. New England has 2,000 MW of inland and 2,000 MW of offshore wind.
Midwest Coal/Wind plus New England Wind (Offshore Only)	
Midwest coal (9,600 MW) + offshore NE wind (4,000 MW)	Inject 9,600 MW of Midwest resources into Norwalk, assuming 9,600 MW of "coal" capacity. New England has 4,000 MW of offshore wind.
Midwest coal/wind (9,600 MW) + offshore NE wind (4,000 MW)	Inject 9,600 MW of Midwest wind and coal by into Norwalk, assuming 4,800 MW of "coal" capacity and 4,800 MW of "inland" wind profile energy. New England has 4,000 MW of offshore wind.

Case Name	Description
Midwest wind (9,600 MW) + offshore NE wind (4,000 MW)	Inject 9,600 MW of Midwest resources into Norwalk by assuming 9,600 MW of "inland" wind profile energy. New England has 4,000 MW of offshore wind.
Midwest Coal/Wind without Additional New England Wind	
Midwest coal (9,600 MW), remove 5,500 MW NE wind from alternate base	**9,600 MW**: Modify cases 1 and 27: Remove 5,500 MW of New England wind; add 9,600 MW of coal from Midwest.
Midwest coal/wind (9,600 MW), remove 5,500 MW NE wind from alternate base	**9,600 MW**: Modify cases 1 and 27: Remove 5,500 MW of New England wind; add 4,800 MW of coal and 4,800 MW of wind (inland wind profile) from Midwest.
Midwest wind (9,600 MW), remove 5,500 MW NE wind from alternate base	**9,600 MW**: Modify cases 1 and 27: Remove 5,500 MW of New England wind; add 9,600 MW of wind (inland wind profile) from Midwest.

Appendix B
Correspondence and Initial Study Request

- Letter from Governor Baldacci to ISO New England requesting technical support to develop a regional blueprint, January 22, 2009.
- ISO's reply to Governor Baldacci offering support to the governors, February 2, 2009.
- Letter from NESCOE to the ISO requesting an economic study, March 27, 2009.
- NESCOE presentation to the Planning Advisory Committee, March 31, 2009.

Appendix C
Scope of Work

- New England 2030 Power System Study Demand and Resource Assumptions, PAC meeting, May 15, 2009.

Appendix D
Study Results and Spreadsheet

- Economic Study Results and Transmission Configurations, New England congressional delegation briefing, Washington, D.C., July 22, 2009.
- Preliminary Economic Study Results, PAC meeting, August 14, 2009.
- Preliminary Cost Estimates for Transmission Configurations, PAC meeting, August 14, 2009.
- Conceptual Wind Zones and Potential Transmission and Conceptual Interconnection Transmission Scenarios, Planning Advisory Committee meeting, August 14, 2009.

The complete study results are posted in Excel format on the ISO Web site; http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/reports/index.html.

Appendix E
Midwest Scenarios
and Potential Transmission

For comparison, the ISO's economic study evaluated several scenarios with New England importing approximately 9,600 MW of power from the Midwest based on the Joint Coordinated System Plan (JCSP) Study proposal to supply power to the eastern United States.[24] The source of energy from the Midwest was assumed to be combinations of wind and coal. The ISO evaluated these scenarios using the same metrics as the other cases.

The JCSP proposal envisioned building new transmission lines to move power from the Midwest to the eastern United States, as far as the New York–New England border. The JCSP proposal would require significant additional transmission investment within New England to deliver power to the region's load centers; the ISO's study identifies preliminary cost estimates for this potential transmission within New England. Finally, the ISO's study developed several scenarios identifying New England's potential share of the cost of transmission from the Midwest.

JCSP Case

The ISO study includes cases that model approximately 9,600 MW of additional import capability based on the assumptions in the JCSP Study. The specific Midwest cases are included in the List of Cases in Appendix A.

Because the source of energy from the Midwest under the JCSP proposal is unknown, the ISO modeled three alternatives for this case:

1. 100% coal (9,600 MW)
2. 50% coal and 50% wind (4,800 MW of coal and 4,800 MW of wind)
3. 100% wind (9,600 MW of wind with inland wind profile)

The study evaluated the Midwest scenarios with and without the New England wind scenarios.

For the three targeted cases without the New England wind scenarios, the study removed 5,500 MW of potential New England wind resources identified earlier in this report so that the JCSP scenarios could be evaluated on its own. If the JCSP cases were modeled with energy from New England wind resources, isolating the economic and environmental metrics of the Midwest and New England wind development scenarios would be difficult and could overstate the benefits of the JCSP cases.

Results

Figure 16 shows average annual clearing prices for the base cases and the Midwest scenarios. Figure 17 shows prices for the targeted Midwest cases that remove additions of New England wind.

[24] The JCSP Study included a 20% wind energy scenario that assumed the Eastern Interconnection will meet 20% of its energy needs with wind by 2024. The study assumed that 229,000 MW of new wind capacity will be built by that time and that the bulk of the new wind generators will be built in the western part of the Eastern Interconnection. The JCSP Study assumed new transmission would be capable of delivering approximately 9,600 MW of capacity to the New England border. *Joint Coordinated System Plan 2008* (JCSP'08); http://www.signup4.net/public/ap.aspx?EID=JTXX10E&OID=164.

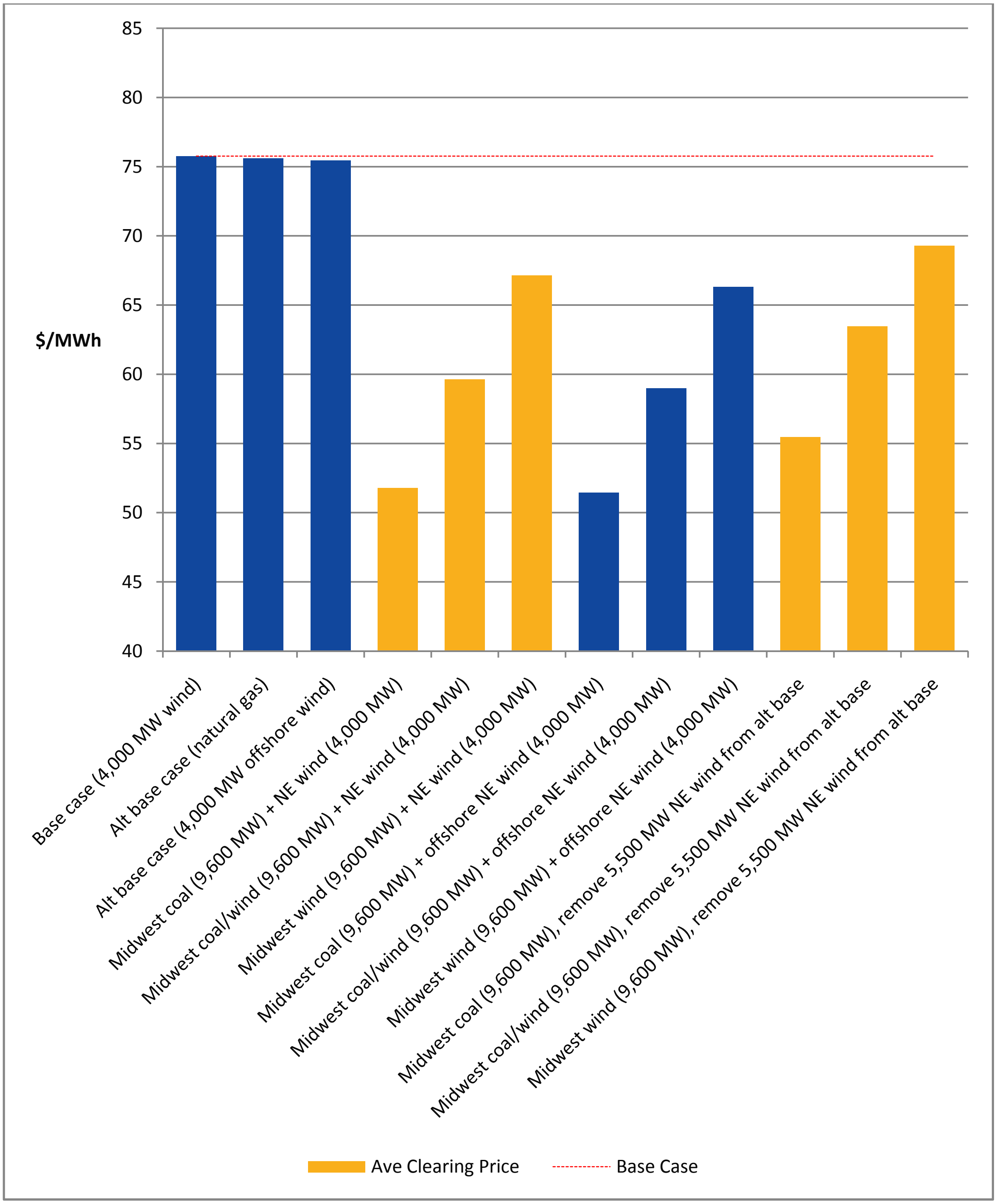

Figure 16: Average annual clearing prices—base cases and Midwest scenarios.

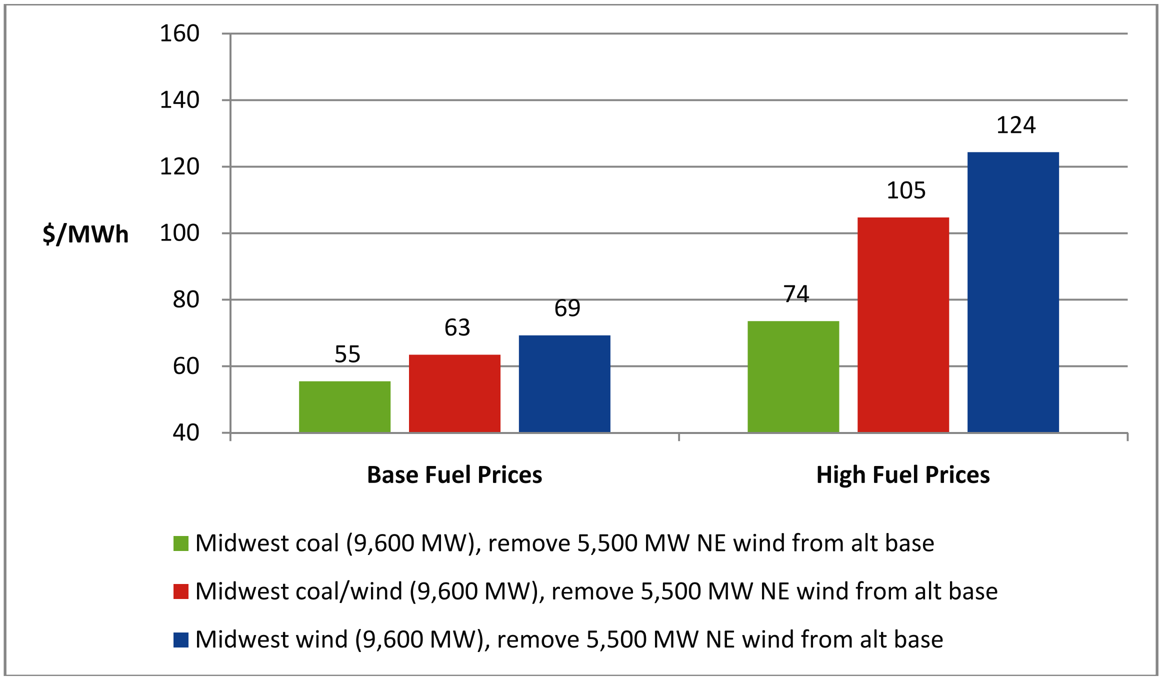

Figure 17: Average annual clearing prices for Midwest scenarios—effect of higher fuel prices.

Figure 18 shows CO_2 emissions for the targeted Midwest cases that remove additions of New England wind. The figure shows CO_2 emissions using base fuel prices and higher fuel prices.

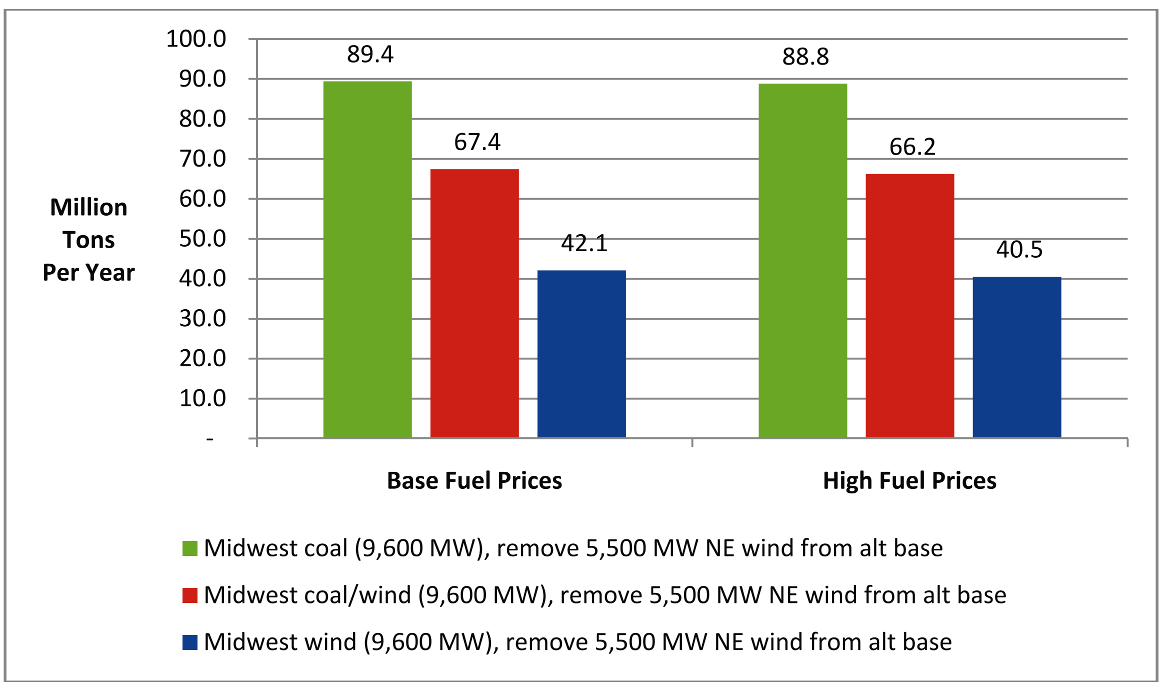

Figure 18: CO_2 emissions for Midwest scenarios—effect of higher fuel prices.

Energy by Fuel Type

Figure 19 shows the percentage of electric energy by fuel type for the base cases and the Midwest scenarios.

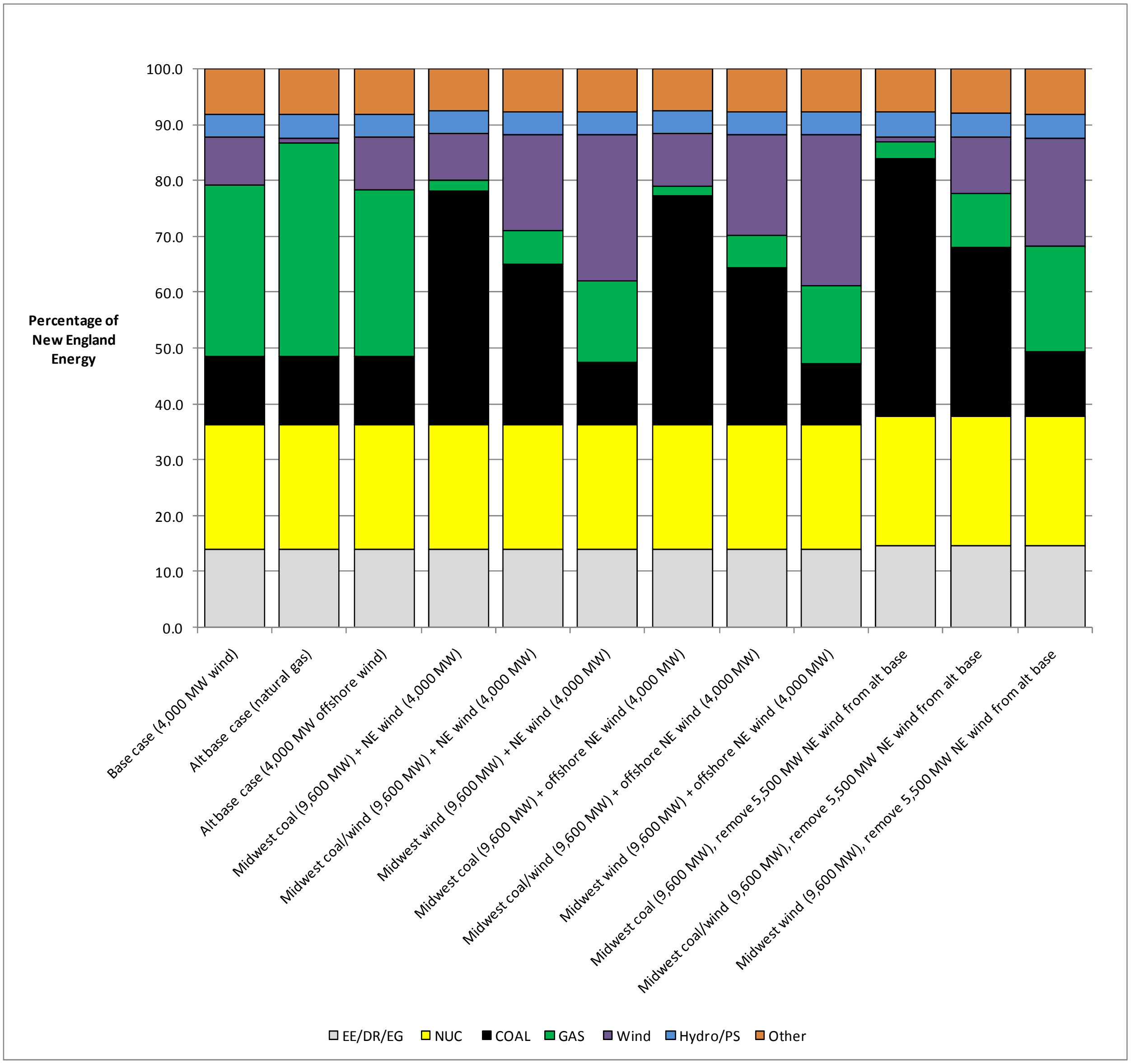

Figure 19: Percentage of electric energy provided in Midwest scenarios, by fuel type.

Table 12 shows the percentage of electric energy by fuel type for the targeted Midwest cases that remove additions of New England wind. The JCSP scenarios produce the highest amount of electric energy from coal because of the assumed increased use of Midwest coal.

Table 12
Percentage of Electric Energy Provided in Midwest Scenarios, by Fuel Type

Midwest Scenarios without New England Wind	Coal	Gas	Nuclear	Wind	EE/DR/EG	Hydro/PS	Other
Midwest coal (9,600 MW) Remove New England wind (5,500 MW)	46%	3%	23%	1%	15%	4%	8%
Midwest coal/wind (9,600 MW allocated 50/50) Remove New England wind (5,500 MW)	30%	9%	23%	10%	15%	4%	8%
Midwest wind (9,600 MW) Remove New England wind (5,500 MW)	12%	19%	23%	19%	15%	4%	8%

Potential Transmission within New England

Since the JCSP Study assumed power would be delivered only as far east as the New England border, the ISO determined that additional transmission would be required within New England to support the Midwest scenario. The ISO and EIG developed a potential transmission configuration that would be required to deliver power from the Midwest into New England. A map of this potential transmission is depicted in Figure 20.

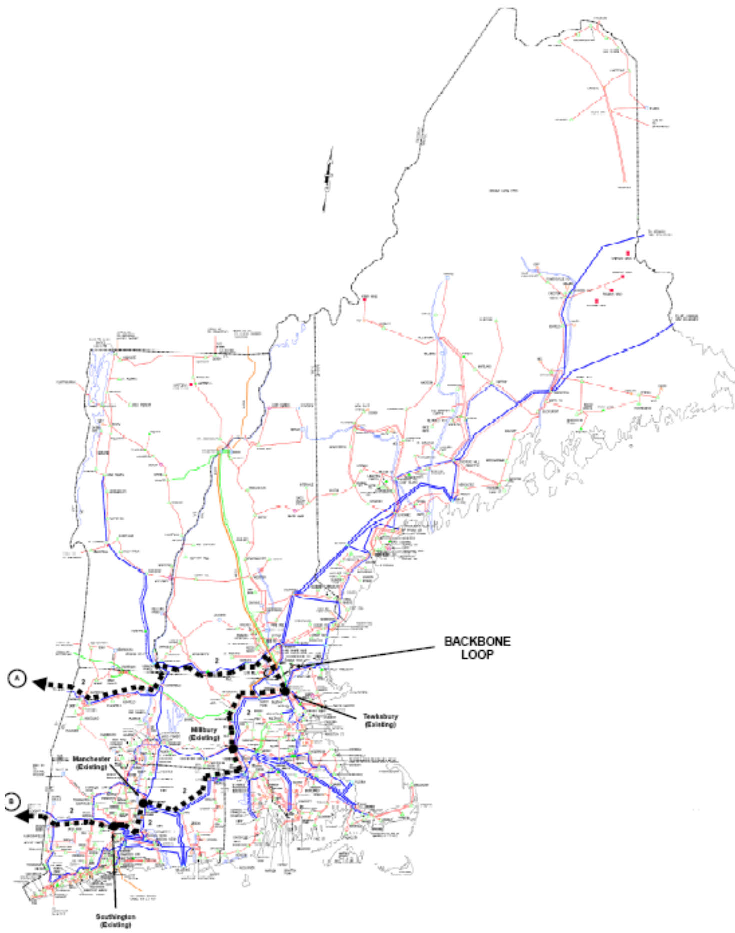

Figure 20: Potential transmission for the Midwest scenario (conceptual illustration only).

The configuration contemplates a new twin-subloop, dual-circuit overhead 500 kV or 765 kV backbone transmission system to facilitate the delivery of approximately 9,600 MW of power from the Midwest through New York to four southern New England load centers (i.e., the Southington and Manchester substations in Connecticut and the Millbury and Tewksbury substations in Massachusetts).

This configuration would require the construction of approximately 1,020 circuit miles of new transmission in New England. If future detailed planning studies show that this configuration cannot be implemented at the 500 kV level, 765 kV would be used. (This scenario is separate from the case that assumes 1,500 MW of wind from New York delivered across the existing New York–New England transmission interface.)

Transmission Cost Estimates

The JCSP Study identifies approximately 15,000 circuit miles of mostly non-New England transmission lines and substations—primarily 765 kV alternating current (AC) and +/-800 kV HVDC—to transport energy from the Midwest to multiple locations in the eastern United States at a cost of $80 billion (stated in 2024 dollars). This JCSP cost estimate is significantly below New England's experience with the actual cost of building transmission and substations and appears to be below benchmarks for other regions. This suggests that the JCSP may have significantly underestimated the transmission costs associated with delivering power to New England, in particular.

EIG identified typical cost-per-mile figures to build transmission in New England and applied these estimates to the Midwest-to-New England transmission lines envisioned in the JCSP proposal. EIG estimated the JCSP Plan proposal could cost approximately $160 billion using actual New England cost-per-mile figures in 2009. Scaling the JCSP cost estimates to equivalent 2009 year dollars shows that the total plan costs would be approximately $50 billion. Based on this approach, the JCSP project could reasonably be more than three times as costly as the JCSP's initial estimate using constant 2009 dollars. Further examination of the JCSP cost estimate is warranted to appropriately evaluate the JCSP case in this study.

Because of the uncertainty about the cost of the JCSP Plan proposal to build transmission from the Midwest to the eastern United States and the uncertainty about cost allocation, the ISO identified a range of potential costs to New England.

ISO New England estimated that the JCSP proposal to deliver approximately 9,600 MW of capacity from the Midwest to the New York–New England border could result in allocating between $15 billion and $36 billion of the potential transmission costs to New England. The ISO estimated that an additional $5 billion to $11 billion of transmission investment would be required within New England to deliver this capacity to the load centers in southern New England. This could result in total costs to New England of $20 billion to $47 billion for the Midwest scenario.

Table 13 summarizes the amount of capacity and energy associated with the Midwest scenario and potential transmission from the Midwest and within New England, and preliminary cost estimates for this transmission.

Table 13
Midwest Scenario—Capacity, Electric Energy, and Potential Transmission

Case	New Capacity (MW)	Percentage of New England Energy	Approx. Circuit Miles of New Transmission	Preliminary Order-of-Magnitude Cost-Estimate Range by Voltage Class (Billions of 2009 $)
Import wind from the Midwest *100% wind from Midwest, no coal* *No wind added in New England*	9,600	19.3	~15,000 total from the Midwest (JCSP Plan) *plus* 1,020 in New England	Midwest to New England: $15 to $36 *plus* reinforcements in New England: $5 to $11 Total: ~$20 to ~$47

Transmission Cost Allocation Scenarios

To account for the uncertainty of the cost of the JCSP Plan proposal to build transmission from the Midwest to the eastern United States and the uncertainty about cost allocation, the ISO identified a range of potential costs to New England. Cost allocation was not discussed in the final JCSP report, and resolving this matter would require significant and broad stakeholder review and discussion. Opinions on cost allocation vary widely across the country and throughout various sectors of the electric power industry. New England has established a series of bright-line thresholds that must be satisfied for reliability upgrades to the New England transmission system to qualify for regionalization of the costs. Allocation of costs for transmission projects intended to support economic or market efficiencies remains a topic for discussion.

Without advocating for any form of cost allocation, the ISO has looked at the possible costs associated with various forms of cost allocation and has applied that logic to the JCSP scenario in an attempt to bracket the range of possible outcomes.[25] In addition, the ISO assumed total transmission project costs of $160 billion to build transmission from the Midwest to the eastern United States based on projections from EIG. Based on various cost allocation methodologies, the ISO estimated that New England's share of these facilities could be in the following range:

- $14.8 billion, assuming that costs are allocated based on New England's share of the exports from the Midwest (9.2%); or,
- $18.5 billion, assuming that costs are allocated based on New England's share of the peak load for the East Coast regions of New England, New York, PJM, and TVA (11.6%); or,
- $27.6 billion, assuming that costs are allocated based on New England's share of the JCSP Study's estimated load-serving entity savings (17.3%); or,
- $36 billion, assuming that costs are allocated based on New England's share of the JCSP Study's estimated production cost savings (22.8%).

[25] Based on JCSP '08, Tables 5-3, 5-10, and 5-41.