New England Electricity Scenario Analysis:

Exploring the economic, reliability, and environmental impacts of various resource outcomes for meeting the region's future electricity needs

August 2, 2007

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Executive Summary

New England's public officials and other stakeholders face a number of issues with respect to the future path for the region's electric power system. In the past decade, New England has seen substantial investment in new power production facilities—made in response to market signals and regional energy-related policies. Most of these new power plants, which were planned and built when natural gas prices were forecast to remain relatively low, generate electricity using natural gas as the primary fuel. Even though the newer plants are much more efficient (i.e., they consume less fossil fuel overall) and have lower emissions than the older plants, natural gas prices have doubled since 2000, which has resulted in electric energy price spikes and concerns about the lack of fuel diversity and overall system reliability.

This situation is challenging for a number of reasons. Residents and businesses expect reliable power on demand, and they want it at reasonable and competitive prices. But New England has long been a region with high energy costs and some of the highest retail electricity prices in the nation, and policymakers are searching for ways to lower, or at least stabilize, electricity bills. At the same time, policymakers and consumers alike want the power sector to continue to make environmental progress, as exhibited by many New England states adopting air emission regulations that are stricter than those required by the U.S. Environmental Protection Agency (EPA) to limit sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2).[1] New England policymakers also want the region's electricity consumers to pursue energy efficiency to a greater extent than in the recent past. To improve system reliability, system planners have identified the need to diversify the types of fuels used to generate electricity and decrease the region's dependence on natural gas.[2]

Simultaneously accomplishing these economic, reliability, and environmental objectives is highly complex. Given the region's lack of indigenous fuel supplies, its dependence on imported fossil fuels, and its tightening environmental policies, substantially reducing regional electricity costs will be difficult. The challenge for policymakers is to find an appropriate balance between economic and environmental goals while ensuring reliability.

In theory, many options are available for satisfying New England's electricity needs. Among them are ways to reduce demand, such as by increasing the use of more efficient electrical appliances and equipment or by installing devices to cycle appliances on and off during peak hours or shift load off-peak. On the supply side, new transmission lines that allow more power to be imported can be built, and renewable resources such as wind farms and solar photovoltaic (PV) projects, new gas-fired

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[1] Sulfur dioxide and nitrogen oxides contribute to the formation of acid rain and smog, respectively, and carbon dioxide has been linked to climate change.

[2] *2006 Regional System Plan* (hereafter cited as RSP06) (Holyoke, MA: IS0 New England, October 26, 2006) Section 6, and *2005 Regional System Plan* (hereafter cited as RSP05) (Holyoke, MA: ISO New England, October 20, 2005) Section 5. Available online or by contacting ISO Customer Service at 413-540-4220.

power plants (despite fuel-diversity issues), and even new coal or nuclear power plants, to name a few, can be added. While some of the technologies may come about naturally as a result of market forces, others may require a change in public policy to encourage their development.

To help clarify some of the economic, reliability, and environmental impacts of various technologies on the New England power system, the ISO sponsored a regionwide initiative, the New England Electricity Scenario Analysis.[3] For over eight months beginning in fall 2006, the ISO worked with a Steering Committee, a number of focused working groups, and a plenary group made up of over 100 representatives from the ISO, utility and environmental regulators from the New England states, market participants, environmental and efficiency advocates, and other interested stakeholders. Together, these participants identified and analyzed a number of supply- and demand-side resource scenarios, each revolving around a particular type of technology.[4]

Goals and Caveats of the Scenario Analysis

The ISO's intention for this boundary analysis was to present a one-year snapshot of a comparable set of diverse outcomes, directions, and impacts that might reasonably be expected to occur *if* one electric technology were pursued over another. The aim of the initiative was to provide a public venue for examining and discussing how the various ways of supplying electricity to the region that were presented in the analysis could affect the costs to provide power, the system's overall reliability, and the environment. Another goal was to provide information and data that regional policymakers and other stakeholders could consider as they develop policies and investments and take other actions in the near term that can affect New England's electricity markets, power system reliability, environmental performance, and meeting consumer electricity needs in the long term.

Due to the global uncertainties involved in predicting oil and gas prices, the Scenario Analysis did not predict what the future would look like in New England or prescribe one particular scenario over another.[5] Rather, it presented a range of results for the different technologies. Furthermore, the analysis did not consider a full economic model of the region, such as overall regional economic development, demographic changes, job impacts, patterns of urbanization, technological innovation, and the adoption of electrotechnologies.[6] Although the analysis presented 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 these 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.

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[3] In general, the ISO ensures the day-to-day reliable operation of New England's bulk power generation and transmission system; oversees and ensures the fair administration of the region's wholesale electricity markets; and manages comprehensive, regional planning processes. In particular, the Scenario Analysis process was designed to support the regional planning processes.

[4] In general, *supply-side resources* are generating units that use nuclear energy, fossil fuels (such as gas, oil, or coal), or renewable fuels (such as water, wind, or the sun) to produce electricity. *Demand-side resources* are measures that reduce the use of electricity in homes, offices, and industries, and for other uses. Demand-side measures include the adoption of more energy-efficient building codes, the installation of highly efficient appliances (such as refrigerators or lighting), advanced cooling or heating technologies, electronic devices to cycle air conditioners on and off during day-time hours, and equipment to shift load to off-peak hours of demand.

[5] Consistent with its mission, the ISO remained relatively neutral in depicting the technologies and avoided taking a position on any technology outcome. It selected simplifying modeling assumptions and approaches to provide insights into the issues rather than specific approaches to developing any specific technology.

[6] Other entities may be able to analyze these other factors using the results of this Scenario Analysis.

The Seven Scenarios

Seven basic scenarios or technology outcomes were selected for analysis:

- **Scenario #1—The "Queue" Mix,** reflecting a combination of power plant technologies that were proposed in New England as of September 30, 2006, notably including gas-fired "peaking" units, combustion turbine (CT) units, and renewable resources[7,8]
- **Scenario #2—Demand-Side Resources,** including energy-efficiency (EE) technologies, which reduce electricity use for a given level of system load, and demand-response (DR) measures, which shift usage from on-peak to off-peak hours or reduce it during regionally high peak-demand conditions[9,10]
- **Scenario #3—New Nuclear Plants,** built at or near existing nuclear stations in New England
- **Scenario #4—New Coal-Fired Power Plants Using Integrated Gasification Combined-Cycle (Coal IGCC) Technology**, which gasifies coal and then runs the gas stream through a combined-cycle power production facility
- **Scenario #5—New Natural-Gas-Fired Combined-Cycle (NGCC) Power Plants,** reflecting additional new power plants similar to those added in large numbers in the region over the past decade
- **Scenario #6—New Renewable Plants,** reflecting a combination of new renewable technologies, including offshore wind, inland (onshore) wind, small hydroelectric power, biomass, fuel cells, landfill gas (LFG), combined heat and power (CHP) systems, and solar photovoltaic (PV) technologies
- **Scenario #7—Increased Imports of Hydroelectric Power and Other Low-Emission Resources,** reflecting new transmission investment to support a significant amount of new power supply imports from both Canada and New York

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[7] The date of September 30, 2006, coincides with the start of the Scenario Analysis initiative.

[8] Relative to other types of resources, a *peaking* unit is designed to start up quickly on demand and operate for only a few hours, typically during system peak days, which amounts to a few hundred hours per year. These units (e.g., combustion turbines) tend to have relatively low capital costs but high production costs.

[9] *Demand response* is when a demand-side resource reduces its consumption of electricity in exchange for compensation based on wholesale electricity prices. The ISO can request participants in its demand-response programs to reduce demand to maintain system reliability. Participants can also voluntarily reduce demand in response to high wholesale prices. The ISO operates three reliability-activated demand-response programs and two price-activated load-response programs. For additional information on demand response, refer to the ISO's *2006 Annual Markets Report*.

[10] Although a wide variety of technologies qualify as demand-side resources, the Scenario Analysis did not attempt to model explicit demand-reducing measures or programs. In reality, some measures provide more or less energy savings over the course of different time periods than was assumed for the Scenario Analysis modeling. While the experience in recent years in New England has been to primarily use demand-response resources to reduce demand during high peak hours, these resources can also reduce demand during a greater number of hours. Advancements in technology allow cycling of heating and cooling systems, refrigeration, lighting, and other electricity uses on a year-round basis. Therefore, demand-response measures might be able to provide greater energy savings than assumed in these analyses.

Assumptions and Methodology

To simplify what would otherwise be too complex an analysis to accomplish within the framework of this project, the Scenario Analysis examined New England's electric system during a single future year. The analysis envisioned a peak system demand of about 35,000 megawatts (MW) in the timeframe of beyond 2020 to 2025.[11] The timeframe for studying the system was far enough into the future to avoid knowing exactly when this level of demand would be reached.

In addition to the demand level, the analysis used a number of assumptions common to all scenarios about certain elements of the future state of the electric system—the resource mix, future fuel prices, operational characteristics of the region's existing fleet of power plants, incremental transmission costs for certain scenarios, and rates of various air emissions and costs for emission allowances.[12] To analyze the sensitivity of the results to changes in some key variables, the ISO modeled cases using alternative assumptions for fossil fuel prices (a case with low natural gas prices and a case with significantly high natural gas prices), prices for carbon emission allowances (a low- and high-price case), the type and degree of penetration of demand-side resources, the retirement of the oldest power plants in the region, and several other variables.

Accounting for these assumptions and the system's existing generation and transmission facilities, the ISO modeled how various combinations of resources within each scenario performed in supplying customers' electricity needs. The simulations represented system performance in all hours of the single future "study year." The analysis ran a total of 52 simulations using these different sets of assumptions.

For each scenario and associated sensitivity analyses, the results included systemwide economic, reliability, and environmental metrics. Economic metrics included the following:

- Average and total systemwide costs to produce power
- Overall efficiency in producing power
- Average clearing prices in New England's wholesale electric energy markets
- A comparison of net revenues that each type of resource was assumed to gain in New England's wholesale power markets with the capital investment for different technologies, given ranges of capital and operating costs for each type of resource and certain transmission and fuel costs

These economic metrics provided basic information for comparing the costs of the various technologies and, for each scenario, comparing net revenues with total capital and operating costs. However, comprehensive cost-comparative information would need to consider site-specific costs and revenues over several years and include tax incentives (e.g., investments in renewable, nuclear, and coal IGCC technologies) as well as other costs and revenues. Therefore, the metrics presented in this

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[11] New England's highest electricity usage to date (28,130 MW) occurred on August 2, 2006. The ISO is planning for a 2007 summer peak of 27,360 MW—or higher (29,160 MW)—in the event of extreme hot weather conditions. One megawatt serves 750 to 1,000 homes.

[12] An *emissions allowance* is a regulatory agency's authorization to emit up to certain amount of a pollutant, such as one ton, over a specified period (e.g., one season, one year, three years). Under several existing and potential federal and regional programs, generating units will be able to purchase or trade allowances.

analysis suggest, rather than fully explain, the reasons for the cost differences among the technology options.

The reliability metrics included the amount of electricity produced by the different types of power plants, total fuel consumed to produce power (by type of fuel), and exposure of the electric power system to various types of fuel-related shortages.

The environmental outcomes that were tracked include such metrics as systemwide emissions of SO_2, NO_X, and CO_2; the 10 highest daily NO_X emissions for peak-load summer days; and the generation sources that contribute to such emissions on peak days. The use of water for cooling new power plants, the incremental amount of land needed to produce and transmit power, and the percentage of power produced by renewable resources were also evaluated.

Key Themes of the Results and Conclusions

The numerous results of the Scenario Analysis show the variations in the economic, reliability, and environmental impacts that the different scenarios had on the electric power system under the range of assumptions used. Some of the key themes that have emerged and the supporting results follow:

- ***Under all the scenarios, New England will continue to depend on natural gas to supply electricity.*** A large amount of gas-fired generating capacity has been built in New England over the past decade. Even adding 5,400 MW of new capacity from a single non-gas-fired technology or resource type (i.e., nuclear, renewables, imports, or energy efficiency) did not change this dependence—in all scenarios, natural gas constituted a minimum of 36% of the systemwide capacity. This is because, in large part, each of the cases assumed that 8,000 MW of new generating capacity was added to a capacity base of approximately 31,000 MW existing in 2007—capacity that is 40% gas-fired. Natural-gas-fired unit capacity under the common set of assumptions for Scenario #5 (NGCC) constituted 50% of the total systemwide capacity of almost 39,000 MW.

  The capacity mix changed the most for the sensitivity cases that assumed the retirement of 3,500 MW of the oldest generating capacity in the region and its replacement with capacity provided by that scenario's core technology. For example, in the case in which 8,900 MW of NGCC generating units were added to meet load growth and replaced retired capacity (Scenario #5, retirement case), the region's dependence on gas-fired capacity increased to 58% of total generating capacity. By contrast, an increase of 8,900 MW of new non-gas-fired capacity (i.e., demand response, nuclear, coal IGCC, imports) meant that natural-gas-fired generation provided approximately 35% of the region's capacity, slightly less than the minimum natural gas capacity under the common set of assumptions.

- ***Fossil fuel prices, particularly for natural gas, drive the region's electric energy mix, electric energy prices, and level of emissions.*** Relatively low natural gas prices tended to decrease the comparative price advantages of coal, shift reliance to gas-fired plants, reduce electric energy prices, and lower air emissions. By contrast, high natural gas prices tended to increase the price of electric energy and increase the overall emissions of SO_2, NO_X, and CO_2. Thus, if gas prices were to increase, emissions would rise as a result of adhering to merit-order dispatch and dispatching power plants that burn more oil. If gas shortages were to occur, commodity prices would increase, and the system would be exposed to fuel interruptions, which would in turn expose New England to greater electric energy price volatility and reliability problems. Over time, however, consumers and suppliers would likely make changes to moderate these effects. Consumers would increase the use of electric energy when prices are low and decrease energy use at higher prices. Suppliers would make similar changes in their investment decisions by investing in more efficiency when electricity prices are higher.

- ***The underlying and unpredictable forces in global oil and natural gas markets could lead to a wide variability of results for the technology outcomes analyzed.*** Adding infrastructure in the regional natural gas supply and delivery systems and lessening gas-sector demands could mitigate price volatility during periods of high demand. Several demand-side technologies [e.g., efficient gas-fired heating systems; additional home insulation; and heating, ventilation, and air-conditioning (HVAC) environmental controls] could provide the dual benefits of reducing the demand for natural gas and electricity while simultaneously reducing the prices for both products.

- ***Across all the scenarios and sensitivity cases, gas-fired power plants tended to be among the last plants dispatched (the so-called marginal units) to serve typical daily loads in New England to meet demand. These plants set the wholesale electric energy clearing prices in most hours of the year, approximately 90% of the time***. The average clearing prices for all the scenarios were sensitive to the price of natural gas, and the overall average clearing prices differed only modestly. However, Scenarios #3, #5, and #6 (nuclear, natural gas combined cycle, and renewables) and a sensitivity case that doubled the amount of energy efficiency had more efficient natural gas units on the margin and average clearing prices that were lower by up to 13% than several other cases.

- ***Under the assumptions for this analysis, the net revenues from the energy markets alone for most of the power technologies evaluated were less than total overall capital and operating costs.*** However, as illustrated in the single-technology sensitivity case that doubled energy efficiency, net revenues were greater than overall costs for energy-efficiency resources and some technologies in Scenario #1 (the queue). The results also showed that the technologies in the queue that had relatively low capital costs, such as natural gas units, were more economically viable than other technology types (e.g., wind and nuclear). For example, wind and nuclear resources tended to have high capital costs and thus would be relatively expensive to build. For these technologies, the analysis showed a modest to significant gap between the net revenues they would receive in the New England wholesale electric energy markets and the annual revenue requirements (ARRs) associated with investment in these technologies.[13] Therefore, to induce investment in these technologies and their entry into the market within a system as modeled, some other means would be needed to fill this revenue gap. These could include payments from the Forward Capacity Market (FCM) or the provision of ancillary services; tax credits; the sale of emission allowances; Renewable Energy Certificates (RECs); long-term purchased power agreements for electric energy,

[13] A plant's *annual revenue requirement* (ARR) is the amount of revenue the plant owner needs to cover the plant's fixed costs for that year. The ARR includes return of and on investment, fixed operations and maintenance costs, and other costs, such as taxes. For the Scenario Analysis, the ARR is assumed to include all costs except for some costs required for producing electricity (e.g., fuel costs and the costs for environmental emissions allowances).

capacity, or both; counting capital costs in the rate base; new regulatory provisions or requirements; and other sources.[14,15]

- ***In the context of this analysis, adding large amounts of resources that produced large amounts of electric energy and had low operating costs and low emissions (as in the nuclear and imports scenarios and sensitivity case that doubled energy efficiency) reduced systemwide production costs, energy prices, and emissions.*** Just as the overall efficiency of the region's power system has improved in the past decade—as newer, more efficient power plants with lower air emissions have been added—the scenarios showed continued improvements in the overall systemwide efficiency of converting fossil fuels to electrical energy. The scenario cases in which the region's oldest generating capacity was retired further underscored this result, producing fewer overall emissions of NO_X, SO_2, and CO_2 and lower production costs.

- ***New England's CO_2 emissions from the power sector varied considerably across the scenarios (and within some scenarios, depending on the assumptions about such variables as fuel prices, emission allowance costs, and unit retirements).*** The results of the analyses indicate that to meet the region's CO_2 emissions targets under the Regional Greenhouse Gas Initiative (RGGI), the different scenarios and sensitivity-analysis cases would need to add substantial amounts of low- or zero-CO_2-emitting resources to the region and some combination of economically based actions.[16] These actions could include requiring regulated power plants, for example, to rely on offsets from other sectors; buy additional CO_2 allowances from sources outside New England, but within the RGGI region; use previously banked allowances; and redispatch facilities to burn fossil fuel (or no fuel) more efficiently and thus to lower carbon emissions. Adding more renewable sources of power with no or low CO_2 emissions in areas far from load centers or importing more hydroelectric power would require the region to build substantially more transmission to move this power to the load centers.

- ***Adding significant demand-side resources provided capacity and electric energy benefits to the system and resulted in fewer emissions.*** Energy efficiency lowered the growth of peak demand, as well as the demand for electricity across the many hours of the year. Energy efficiency, with operating characteristics that are similar to baseload or intermediate units, also provided both capacity and energy savings.[17] Another result was that demand-response

[14] The Forward Capacity Market is a wholesale capacity market to encourage investment in demand and supply resources. Under the FCM, the ISO will project the needs of the power system three years in advance and hold an annual auction to purchase the power resources that will satisfy the future regional requirements.

[15] A *Renewable Energy Certificate* represents the environmental attributes of 1 MWh of electricity from a certified renewable generation source for a specific state's Renewable Portfolio Standard (RPS). Providers of renewable energy are credited with RECs, which are usually sold or traded separately from the electric energy commodity (see Section 1.4 and Section 5.3.2).

[16] The Regional Greenhouse Gas Initiative is a 10-state CO_2 cap-and-trade program being developed and implemented in the Northeast. Under RGGI, the Northeast region must cap its emissions by 2014 on the basis of recent historical emissions and reduce this level by 10% by 2018. By 2018, the six New England states will be allocated 50.2 million tons of carbon allowances from the RGGI cap, which covers other states in the Northeast region (i.e., New York, New Jersey, Maryland, and Delaware).

[17] *Baseload* generating units satisfy all or part of the minimum load of the system and, as a consequence, produce electric energy continuously and at a constant rate. These units are usually economic to operate on a day-to-day basis. *Intermediate-load* generating units are used during the transition between baseload and peak-load requirements. These units come on line during intermediate load levels and ramp up and down to follow the system load that peaks during the day and is at its lowest in the middle of the night.

resources, which have operating characteristics similar to peaking units, tended to provide capacity but less relative electric energy to the system in other hours.

- ***Additional transmission and distribution investment may be needed to support various technologies, depending on where actual resources are added in the future.*** To a limited degree, the Scenario Analysis examined the transmission implications of different types of resource technologies for the system and found that incremental investments may well be needed to support the system's transmission and distribution needs in the future. For example, significant transmission investment would be needed in New England under the import scenario, and, while not modeled, it also would likely be needed in Canada. Because it is not known where any actual demand-side or supply-side resources might actually develop, the Scenario Analysis used simplifying assumptions about transmission and distribution costs.

In summary, the results of the Scenario Analysis suggest that, absent policy changes, natural gas resources will be the capacity of choice. The addition of natural gas resources is consistent with recent experience, the types of resources in the queue, projections of net revenues exceeding the annual revenue requirements for inexpensive units, and the air emissions constraints, including RGGI. However, an expansion of the natural gas capacity would expose New England to potentially high prices and additional fuel-diversity issues.

The Scenario Analysis produced detailed information about the scenarios—the economic, reliability, and environmental impacts of the expansion technologies on the region's future electric power system and how these impacts change under different sets of assumptions. This summary provides only the tip of the "information iceberg." Additional results are summarized in this report; all the results are available to the public on the ISO Web site.

To assist stakeholders in analyzing the data that became available as part of the Scenario Analysis, the ISO has posted on its Web site a spreadsheet tool that stakeholders can use to explore the information, make their own investigations, and assess the impacts of making different assumptions (i.e., about capital costs, transmission needs, gas delivery infrastructure costs, and the like). The ISO encourages interested parties to compare the results for the different scenarios and reach their own conclusions about the various outcomes.

Consistent with the original objectives of this initiative, the Scenario Analysis stops short of indicating what steps the region should now carry out. The ISO is willing to continue to work with policymakers and stakeholders to define the next stage of this analysis.

Section 1 Introduction

New England's electricity infrastructure and marketplace currently provide the region's 14 million people with a reliable supply of electricity. Over the past decade, substantial investment in the region's electric power system has added much new generation and transmission capacity, distribution system enhancements, and other upgrades to help ensure that the system continuously operates even during unexpected equipment outages.[18] Additionally, substantial investment in demand-side measures has reduced the use of electricity in homes, offices, industries, and for other uses.

Almost 97% of the capacity added in New England since 1999 can burn natural gas. These plants, which were planned when gas prices were forecast to remain relatively low, generate electricity using natural gas as their primary fuel. Since 2002, however, natural gas prices have doubled and are subject to considerable volatility, which has led to relatively high electricity prices for New England's consumers.[19] In addition to being subject to this price volatility, the region is more vulnerable to short-term seasonal reliability issues because it relies heavily on natural gas.[20] Adding to this need for enhanced fuel-supply diversity is the need to add more capacity in the long term, as indicated by the long-range capacity and resource adequacy forecasts conducted as part of the ISO's regional system planning process.[21] In planning for this fuel-diverse capacity, the region must comply with environmental regulations at all levels that aim to protect the region's air, land, and water.

New England's future economic health depends on the region having a reliable, competitively priced, and environmentally sound supply of electricity—one that could minimize the impacts of variations in electricity costs that result from changes in fuel prices or fuel availability. Moreover, an increase in the use of demand-side resources could provide an economically efficient mix of resources systemwide that could in turn decrease the need to build new facilities; ease the burden on existing infrastructure and land and water resources; and result in lower power plant emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon dioxide (CO_2), and mercury (Hg).[22] Many options, both supply and demand side, are available to accomplish these objectives. Among the well-known demand-side resources that could be available in the near term are the following:

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[18] Between 2000 and 2004, private companies have invested more than $6 billion in new, modern power plant capacity, adding 9,000 megawatts (MW) of supply. The ISO's demand-response programs have grown from approximately 100 MW in early 1997 to more than 900 MW enrolled in early 2007. Also since 2000, New England's transmission companies have put into service close to 200 transmission system enhancements for reliability purposes. By the end of 2007, this will represent an investment of approximately $1.5 billion.

[19] *2005 Annual Markets Report* (hereafter cited as AMR05) (Holyoke, MA: ISO New England, June 1, 2006) and *2006 Annual Markets Report* (hereafter cited as AMR06) (Holyoke, MA: ISO New England, June 11, 2007).

[20] *2006 Regional System Plan* (hereafter cited as RSP06) (Holyoke, MA: IS0 New England, October 26, 2006) Section 6. RSP06 is the ISO's the most recent annual planning report that contains information about the resources and transmission facilities needed to maintain the reliable and economic operation of New England's bulk electric power system over a 10-year horizon.

[21] RSP06, Section 4.

[22] Sulfur dioxide is a main contributor to acid rain, and nitrogen oxides contribute to increased ozone levels (smog), especially during summertime conditions—the very periods when the region's electricity use and power production peaks (see http://www.epa.gov/interstateairquality/). Carbon dioxide contributes to greenhouse gases and has been linked to climate change (see Intergovernmental Panel on Climate Change Working Group 1. Physical Science Basis; Fourth Assessment Report of the IPCC, *Summary for Policymakers*. World Meteorological Organization and United Nations Environment Programme, April 2007. Mercury emissions have been shown to have detrimental health effects (see U.S. EPA. Mercury Web page. (Accessed April 23, 2007).

- Using energy-efficient light bulbs, refrigerators, air conditioners, and other equipment and adopting other advanced energy-efficiency measures in homes, offices, appliances, and industrial processes[23]

- Incorporating provisions into the building codes for homes and offices that require new structures to use equipment and processes that are more energy efficient than standard ones

- Shifting the use of appliances (e.g., dishwashers and washing machines) from on-peak (summer afternoon) to off-peak (summer morning or evening) periods

- Using automatic devices to cycle equipment on and off during on-peak hours (e.g., briefly turning off air conditioners during those same summer-peak hours), which is called *demand response*[24]

- Using advanced meters and software that show generally transparent real-time price signals to consumers as an incentive for them to modify their use of electricity as the cost to supply it changes over the course of the day (i.e., *price-activated demand response*)—for example, when consumers switch to using small-scale on-site "distributed" generation (DG)

A lesser known but mature and commercially available demand-side resource is off-peak cooling with thermal energy storage. This technology shifts air-conditioning and cooling loads from on-peak hours to off-peak hours by using chiller equipment to store coolness on ice, in chilled water, or in phase-change materials for use when needed during peak hours.

Available supply-side options include the following measures:

- Adding wind, solar, biomass, photovoltaic, and other renewable resources

- Upgrading long-distance transmission systems to provide greater imports of power supplies from outside the region

- Building new gas-fired, coal, or nuclear power plants

These options involve a range of different trade-offs, risks, and uncertainties related to (1) which types of technologies to pursue or invest in and at what locations; (2) whether transmission and distribution delivery infrastructure would be needed and how much; (3) what the investment payback periods would be; (4) what the local and regional environmental outcomes could be; (5) how much the region would need to rely on fuel sources from outside the region; and (6) what ratemaking and rate-design policies would be needed to send appropriate signals to utilities and customers—to name a few. Some of these trade-offs are well-known; others are less obvious or easily understood.

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23 *Energy-efficiency* measures reduce the energy inputs for a given level of service or increase or enhance services for a given amount of energy inputs. Additional information is available online at http://eia.doe.gov/emeu/efficiency/definition.htm.

24 *Demand response* occurs when a demand-side resource reduces its consumption of electricity in exchange for compensation based on wholesale electricity prices. The ISO can request participants in its demand-response programs to reduce demand to maintain system reliability. Participants can also voluntarily reduce demand in response to high wholesale prices. The ISO operates three *reliability-activated* demand-response programs and two *price-activated* demand-response programs. For additional information on demand response, refer to AMR06.

1.1 Purpose of the Initiative

Recognizing that the region must pursue new energy resources in the near future, and to help clarify some of the trade-offs involved in pursuing the various resource outcomes, the ISO initiated the New England Electricity Scenario Analysis.[25] This initiative sought to inform regional policymakers and stakeholders about various choices for meeting consumers' needs for reliable, economically efficient, and environmentally sound supplies of electricity. By presenting a series of economic, reliability, and environmental results for the system as modeled—for such metrics as electricity production costs and prices, market-based revenues, system reliability, fuel diversity, and emissions—this boundary analysis sheds light on some potential regional implications of each technology outcome for future investment in and policymaking decisions about electricity resources.

Above all, the Scenario Analysis initiative has aspired to help government officials, environmental advocates, and other stakeholders understand possible outcomes and consequences of pursuing one type of technology over another. The intention is for interested parties to use the results as a basis for further discussion in other forums about any preferred outcomes; likely (or unlikely) technology choices given today's policy and market conditions; or policy changes that could induce private investment in a particular technology to attain certain outcomes. For example, if the combination of market forces and current array of public policies do not stimulate investment in a robust set of the desired resources, additional public policies and market incentives—or the removal of disincentives—may be needed.

1.2 The Scenario Analysis Process

For the Scenario Analysis project, the ISO created a Steering Committee, which included representatives from the New England Conference of Public Utilities Commissioners (NECPUC), the New England Power Pool (NEPOOL), and ISO staff.[26,27,28] The committee's role was to generally guide the process, structure the stakeholder meetings, and review and comment on draft discussion documents.

Through a series of open meetings, committees, and technical working groups that began in fall 2006, the ISO worked directly with over 100 stakeholders to develop the scenarios and assumptions.[29] Participation was strong and included broad representation from the industry as well as a range of state government agencies, including electric utility and environmental regulators. As a result, the

[25] In general, the ISO ensures the day-to-day reliable operation of New England's bulk power generation and transmission system; oversees and ensures the fair administration of the region's wholesale electricity markets; and manages comprehensive, regional planning processes. The Scenario Analysis process was designed to support the latter planning processes.

[26] NECPUC is a nonprofit corporation comprising the utility regulators of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. NECPUC provides regulatory assistance about electricity, gas, telecommunications, and water industry issues of common concern to the six New England states.

[27] NEPOOL was formed by the region's private and municipal utilities to foster cooperation and coordination among the utilities in the six-state region and ensure a dependable supply of electricity. Today, NEPOOL members include businesses engaged in all phases of the production, marketing, delivery, and consumption of electricity and serve as an advisory body to the ISO.

[28] Members of the Steering Committee are listed at the Scenario Analysis Web site: http://www.iso-ne.com/committees/comm_wkgrps/othr/sas/mtrls/dec192006/steering_committee.pdf.

[29] The working groups specifically addressed environmental, power supply, transmission, energy-efficiency, and demand-response issues.

ISO heard many diverse views and received and incorporated many technical comments on how the simulations should treat various technologies and systems and address other issues.[30]

The depth and breadth of the results were strengthened by the diversity of data sources used in the analysis. In addition to incorporating data provided by stakeholders, the ISO used data from consultants, academia, trade associations, governmental sources, and leading experts in the field. These data were essential for defining appropriate assumptions and capturing more widely accepted ranges for a number of the simulations conducted.

1.3 Overview of the Assumptions, Approach, and Caveats

The analysis generated a common set of assumptions about certain elements of the future state of the New England electric power system in 2020 to 2025 and beyond. The analysis examined the operations of the system in a single year in the future and, due to the large global uncertainties involved in predicting oil and gas prices, it focused only on issues and impacts directly related to the electric power system.[31] These included an assumed system peak demand of 35,000 MW that new demand and supply resources, together with existing system capacity, must reliably meet. Assumptions also were estimated for future fuel prices, the future capabilities of today's fleet of generating units, and transmission and distribution facilities. To determine the sensitivity of the results to changes in a number of other variables, such as higher and lower forecasts for fuel prices, the retirement of the oldest generating capacity on the system, or the adoption of much more aggressive demand-side resources, the ISO used alternative boundary assumptions for these variables.

Accounting for these assumptions and sensitivities, the ISO modeled how the various combinations of resources in each scenario could perform in supplying customers' electricity needs. A series of economic, reliability, and environmental "outcome" metrics allow for comparing the results of the different scenarios. Although limited in scope, the results of each modeling run demonstrate how the electric power system's costs, reliability, and environmental impacts could vary, given the different technology types and their sensitivities to some key variables. For simplicity and clarity, the model did not account for typical reactions by consumers and suppliers to higher prices. Consumers would be expected to reduce usage over time, and suppliers would be expected to invest in more fuel-efficient technology, if electricity prices increased (e.g., due to fuel-price increases).

The scenarios selected for modeling and analysis did not attempt to identify "right" or "wrong" electric technologies or develop a plan for what the region *should* do. Nor did they attempt to build consensus about which technologies or outcomes are preferable. Additionally, the analysis was not designed to show what actual futures *will* occur but rather to explore the set of diverse economic, reliability, and environmental impacts or outcomes that *might* reasonably be expected to occur *if* one technology were pursued over another. The analysis specifically was not a least-cost plan or a multi-year, present-worth analysis.

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[30] Throughout this process—which produced significant, thoughtful, and timely contributions for developing this work product—and consistent with its mission, the ISO remained relatively neutral in depicting the technologies and avoided taking positions on any technology outcome. To reflect the often opposing information provided by stakeholders, the ISO used ranges of information from the literature. Additionally, it selected simplifying modeling assumptions and approaches to provide insights into the issues rather than solutions to specific problems.

[31] It was recognized that larger economic forces help shape the region's patterns of energy production and use, which in turn have an impact on the electric power system economics, system reliability, and the environment. These other forces include such factors as overall regional economic development, demographic changes, job impacts, patterns of urbanization, technological innovation, and the adoption of electrotechnologies, which other entities may be able to analyze using the results of this Scenario Analysis.

The ISO appreciates the challenges in modeling future states of the region's electric power system. This type of "what if" analysis, however, has several inherent limits, including limits in the ability of quantitative models and other tools to depict how the system would actually operate if the assumed conditions occurred in the future and in the ability to predict how the electric system would interact with other elements of the economy. Because of these limits, the analysis has simplified key elements of the system and qualified its results as being informative of—rather than deterministic about—how future electric technology outcomes might manifest in the region. Additionally, by purposefully adopting scenarios that entail an exaggerated amount of new capacity provided by one particular resource, the process has dramatized the differences among the scenarios. This deliberately provides distinct and clear pictures of possible future states that can be compared readily, rather than providing realistic pictures of the future, which would require more carefully honed sets of assumptions.

1.4 Overview of the Scenarios

The Scenario Analysis examined seven different technology outcomes for New England, which emphasized both supply-side and demand-side options. The seven scenarios, as summarized below, varied according to the type of electricity resource assumed to be added to the system:

- **Scenario #1—The "Queue" Mix.** This scenario reflected the mix of generating technologies currently being proposed in New England, notably gas-fired "peaking" units, combined-cycle (CC) units, and renewable resources. The mix reflected the proportion of the mix of generating resources in the ISO Generator Interconnection Queue as of September 30, 2006.[32,,33]

- **Scenario #2—Demand-Side Resources.** This scenario consisted of significant investment in demand-side resources, including an aggregate of energy-efficiency technologies that reduce or shift load (i.e., customer usage) from on-peak to off-peak hours and measures that send price signals to customers to curtail their use in certain high peak-demand periods. Under the common set of assumptions for this scenario, half of the resources added were energy-efficiency measures, and the other half involved demand-response measures. One of the major sensitivities some of the stakeholders were interested in examining involved doubling the amount of energy efficiency used by removing the equivalent amount of demand response. Another sensitivity case of interest involved doubling the amount of demand response by removing the equivalent amount of energy efficiency.

- **Scenario #3—New Nuclear Plants.** For this scenario, nuclear capacity was assumed to be expanded at or near existing nuclear stations.

[32] Relative to other types of resources, a *peaking* unit is designed to start up quickly on demand and operate for only a few hours, typically during system peak days, which amounts to a few hundred hours per year. These units (e.g., combustion turbines) tend to have relatively low capital costs but high production costs.

[33] The ISO's Generator Interconnection Queue is a list of the requests submitted to the ISO to conduct studies on interconnecting specific power plants to the region's electric power grid. While projects in the queue may not actually be permitted, financed, or constructed, the mix of projects in the queue is a reasonable approximation of the market's response to current conditions and outlooks in the region and private stakeholders' interest in developing projects to meet future requirements given current market and public policies.

- **Scenario #4—New Coal-Fired Power Plants Using Integrated Gasification Combined-Cycle (Coal IGCC) Technology.**[34] This scenario involved adding an advanced coal technology, IGCC, to generate electricity and add to the capacity mix in New England. Unlike conventional coal plants, this technology gasifies the coal, thus allowing the separation of useful energy from waste by-products. After separating the by-products, the gas stream passes through a combined-cycle production facility.

- **Scenario #5—New Natural-Gas-Fired Combined-Cycle (NGCC) Power Plants.** This scenario added new gas-fired combined-cycle power plants similar to those added in large numbers in the region over the past decade.

- **Scenario #6—New Renewable Plants.** This scenario added capacity from renewable resources, such as those sources defined in the states' Renewable Portfolio Standards (RPSs).[35] These resources include onshore and offshore wind, hydroelectric, biomass, landfill gas (LFG), solar photovoltaic (PV), fuel cells, and combined heat and power (CHP) systems. This scenario reflected the effects of expanded state RPSs, which may be in the range of 20 to 25% of total energy consumed by load-serving entities (LSEs) by 2025.

- **Scenario #7—Increased Imports of Hydroelectric Power and Other Low-Emission Resources.** This scenario added new imports of hydro or other low-emission resources, such as wind, from Canadian provinces to the north (Quebec and the Atlantic and Maritime provinces), as well as from the west (New York and Ontario).[36] This scenario considered the different seasonal demand patterns experienced in these (winter peaking) parts of Canada and (summer peaking) New England and improved the use of planned hydroelectric and wind projects.

1.5 Outline of the Report

Following this introductory section, Section 2 describes the basis for the common assumptions about New England's future electricity system that were incorporated into the analysis. The methodology, models, and metrics used to analyze the various technologies are summarized in Section 3. Section 4 provides more details about each scenario and the sensitivity analyses performed in studying each scenario, and Section 5 presents some of the key results of the analyses, comparing the results for various technology outcomes and sensitivities. Section 6 discusses the results and how policymakers and other stakeholders might be able to incorporate them into other analyses more specific to their needs.

[34] A *combined-cycle* facility produces electric power in two stages or cycles. The first stage runs a gas turbine and generator driven by the direct burn of gas, like a jet engine. The second stage uses the heat from the burning gas to make steam that drives a steam turbine and generator. Combined-cycle facilities tend to have a higher capital cost per megawatt of capacity compared with single or simple-cycle power plants, such as combustion turbines, but are significantly more efficient in power output per unit of fuel burned.

[35] Renewable Portfolio Standards are state standards for load-serving entities to provide a portion of their energy from specific renewable technologies, this portion increasing each year. Connecticut, Maine, Massachusetts, and Rhode Island have RPSs, and New Hampshire has recently established one. Vermont is pursuing an alternative approach and is requiring that renewable resources be used to serve all growth in that state's electricity use. The definition of RPS requirements varies by state. Refer to NC State University's Web site, *Database of State Incentives for Renewables and Efficiency* (hereafter cited as DSIRE Database, 2007), for more information on state RPS programs.

[36] Atlantic Canada, also known as the Atlantic provinces, comprises four provinces located on the Atlantic coast: the three maritime provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the province of Newfoundland and Labrador.

Table citations and references listed at the end of the report contain complete information on the data sources cited and used. A series of links to Web pages that contain more detailed information are provided throughout the report. These Web pages contain the presentations made at the stakeholder meetings on the background and scope for the analysis and on the development of the scenarios, assumptions, sensitivity cases, methodology, and metrics used. The Web site also contains the draft reports, preliminary results, stakeholder comments, and data-extraction spreadsheets for examining the data, as well as a user's guide for using the spreadsheets.

Section 2
Systemwide and Technology-Specific Assumptions

To facilitate a comparison of the results, each technology outcome was based on a common set of assumptions about the bulk power system. Several additional, more specific assumptions also were made about each technology. This section summarizes the major assumptions incorporated into the models and post-processing calculations (discussed in Section 3). These assumptions are explained in more detail on the ISO Web site and reflect input from the open stakeholder process.

2.1 Systemwide Assumptions

A common set of assumptions was developed for the analysis that addressed the following characteristics of the electric power system and markets during a single calendar year occurring some time beyond the 2020 to 2025 timeframe:

- Summer peak demand
- New resource level
- The mix of resources (i.e., fuel diversity)
- Expansion of the transmission and distribution systems
- Prices of fuels
- Market structure and revenues

2.1.1 Target Peak Demand

With approximately 31,000 MW of generating capacity expected to be available in summer 2007 to meet a projected summer peak demand of 27,360 MW, the region currently has sufficient supplies to reliably meet customers' needs.[37] However, the starting premise for the Scenario Analysis was that electricity demand in the region will continue to grow, and to reliably meet this future demand, some combination of demand-side resources, new power plants, and transmission expansion will be needed. To reflect customer requirements beyond the 2020 to 2025 timeframe, all seven scenarios assumed that the system needed to meet a summer peak demand of 35,000 MW.[38,39]

Because the Scenario Analysis treated incremental demand-side "resources" on the same basis as other supply-side resources, as opposed to treating them simply as measures to reduce New England

[37] Reliable system operation always includes a level of capacity above expected levels of demand to accommodate planned and unplanned outages on the system, as well as a higher than expected level of electricity use that might occur during extreme weather conditions.

[38] The 35,000 MW level was based on a 50/50 summer-peak demand, which is expected to occur at a weighted New England-wide temperature of 90.4°F and has a 50% chance of being exceeded because of weather.

[39] The analysis assumed the same load-duration curve (i.e., the relative or absolute level of demand, measured in megawatts, in each hour of the year) that was assumed for calendar year 2015 in RSP06. Note that 1 MW serves 750 to 1,000 homes.

load, it was assumed that all scenarios—supply side and demand side—needed to meet the 35,000 MW planning target level. One of the scenarios (Scenario #2; see Section 4.2) added significant new demand-side "resources" to meet the summer-peak demand. One sensitivity case applied to all the scenarios (see Section 3.2.2) assumed that if 3,500 MW of energy-efficiency and demand-response "resources" were available to lower the summer peak demand, 3,500 MW of the new generating resources may not be needed.

2.1.2 New Resource Level

To meet this future level of demand, the Scenario Analysis assumed that 8,000 MW of new resources needed to be added to the existing resource mix to serve customer requirements. Consistent with the ISO's system planning criteria and practices, the analysis assumed that this level of resources would be needed to reliably meet customers' requirements under a range of forecast system loads, resource conditions, and capability of New England and neighboring systems to provide emergency capacity.[40]

The 8,000 MW level of new resources and the total system capacity level of about 39,000 MW—which is greater than the existing supply-side power production, transmission import, and demand-reduction capacity currently installed in the region or discussed in the ISO's most recent long-range system plan—are large but not unrealistic.[41] For example, in summer 1998, the region had 23,171 MW of capacity to meet a summer peak demand of 21,406; this provided a relatively slim margin of reserve supplies.[42] From then until summer 2006, the region had added over 7,500 MW of additional net supply, not counting the demand-side resources that had been added during the decade.[43] Customers' electricity use set a new record peak at 28,130 MW on August 2, 2006—up more than 6,500 MW from a decade ago.[44] The target of an additional 8,000 MW of new resources for no earlier than the 2020 to 2025 timeframe thus seemed a reasonable point to begin the analysis.

2.1.3 Resource Mix

The addition of 8,000 MW to the existing mix of resources means that all the scenarios still depended heavily on the existing fossil-fired generating capacity, even though other technologies and resources presumably were added. Of the roughly 31,000 MW of power production capacity in place today, about two-fifths uses natural gas as its primary fuel, one-tenth uses coal, one-fourth uses oil, one-sixth is nuclear capacity, and approximately one-tenth uses renewable resources. This mix is shown in Figure 2-1.

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[40] The ISO system must comply with Northeast Power Coordinating Council (NPCC) resource adequacy criterion, which states that the "probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in 10 years." Compliance with the criterion can be achieved, in part, through the use of operating procedures designed to mitigate capacity deficiencies and more likely to be invoked during periods of extremely high loads or severe generator-outage conditions.

[41] RSP06.

[42] *NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission* (CELT), Section 1. (Holyoke, MA: ISO New England Inc., April 1999) (Hereafter cited as 1999 CELT Report). This peak load was the actual metered load of the region during summer 1998; the planning target for the summer peak had been 22,108 MW, reflecting what would have been expected under more normal weather conditions. This capacity figure reflects utility-owned generation, nonutility generation, and firm purchases and sales of capacity from other regions.

[43] In summer 2006, net installed capacity (including firm purchases of power from outside the region) totaled 30,895 MW. For additional information, see the *2006 CELT Report.* (Holyoke. MA: ISO New England, 2006), Section 1.

[44] "New England Consumers Set New Record for Electricity Use" (press release) (Holyoke, MA: ISO New England, August 2, 2006).

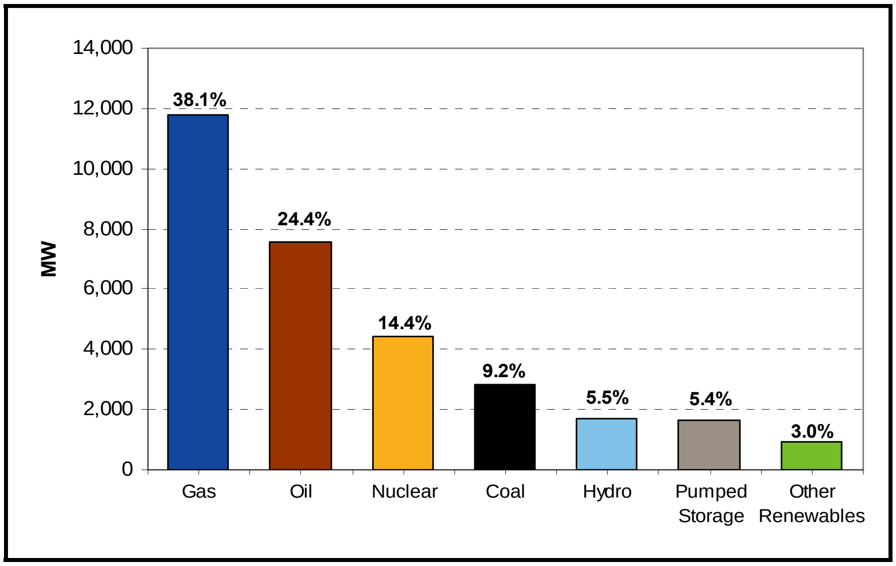

Figure 2-1: New England generating capacity by fuel type, 2006.

Note: Some plants tend to operate more often than these percentages indicate. For example, nuclear plants tend to produce more than one-sixth of the electric energy because they typically operate around-the-clock when not off line for maintenance. Depending on the relative prices of fossil fuels, some plants run less often; for example, many oil-fired peaking units operate only rarely because of their relatively high operating costs.

Source: ISO New England, *2006 Regional System Plan* (RSP06), Figure 4.1.

Of the 8,000 MW of new resources assumed to be added to the system's existing fleet of generation units, the first 2,600 MW was assumed to be a mixture of technologies already in the "development pipeline, " as indicated by the ISO's Generator Interconnection Queue as of September 30, 2006, when the Scenario Analysis initiative began.[45] The Scenario Analysis assumed that the 2,600 MW portfolio of technologies in the queue, which includes wind, biomass, landfill gas, and hydro projects; fuel cell installations; gas-fired combustion turbines (peaking units) and combined-cycle facilities; and coal IGCC projects, represented a reasonable mix of possible future resources. Figure 2-2 shows the mix of generation technologies in the queue as of September 30, 2006.

[45] The queue includes many proposed projects, and past experience indicates that many of these are never built for a variety of reasons. The queue nevertheless represents a snapshot in time of what the market is proposing for a mix of resources.

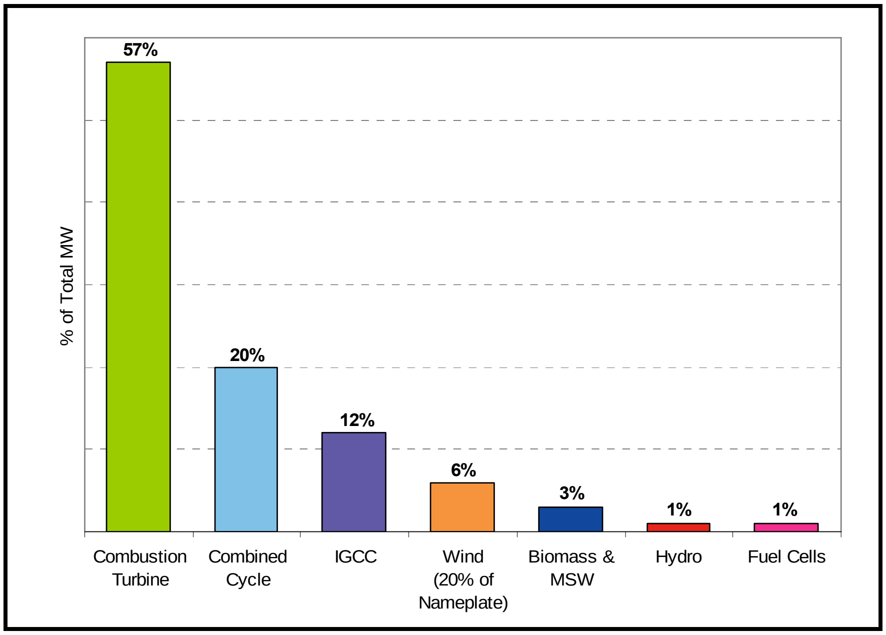

Figure 2-2: The mix of fuels for proposed power plants in the ISO's Generator Interconnection Queue as of September 30, 2006.

Note: All of the technologies are assumed to be at 100% of their nameplate capacity, except for wind, which is assumed to be at 20% of its nameplate capacity.

To create the total 8,000 MW of needed resources for each scenario, in addition to the 2,600 MW blend of technologies common to all the scenarios, each scenario was made up of 5,400 MW of a single dominant supply- or demand-side technology (explained in more detail in Section 4). The different makeup for the remaining 5,400 MW distinguishes the differences in each technology's economic, reliability, and environmental outcomes, more so than scenarios with less varied technology bundles. While it may be unlikely that a single technology or resource type will dominate future electricity developments, such an outcome has been the recent experience in New England.[46]

2.1.4 Physical Configuration of the System

Also common to all the scenarios and simulation models were assumptions about the physical configuration of the electric power system. New England's electric transmission system is a complex array of interconnected transmission facilities linking generation units and customers' loads. The system includes 8,000 miles of high-voltage lines within New England and 12 tie lines interconnecting New England to three neighboring regions.

To simplify the modeling in the Scenario Analysis, however, these simulations assumed a single "one-bus" model of the system (as if it did not experience any transmission congestion). This is consistent with the assumption that the transmission system experienced normal expansion as part of the region's transmission planning process that ensures the full consideration of all planned transmission facilities. To account for additional costs for generic transmission expansion for each of the scenarios, assumptions were made for mileage ranges, installed costs per mile of transmission, necessary acreage for rights-of-way, and substation equipment.

[46] Notably, over 96% of the new power plants added in New England were gas-fired combined-cycle units, accounting for over 90% of the capacity added since 1999. (RSP06)

Similarly, the Scenario Analysis assumed that the local distribution system (i.e., the carrying of power from the high-voltage system to customers' premises) was expanded as needed. The scenarios that added demand-side resources reduced the extent of the need to expand distribution infrastructure.

The analysis did not account for any additional benefits that newly added transmission and distribution infrastructure may provide, such as for meeting future system reliability or local area needs.

2.1.5 Fuel Prices

All seven of the scenarios were analyzed with common assumptions about the level and prices of fossil fuels (oil, natural gas, and coal) used to generate the region's electricity. The starting point was a "base-case" fuel-price forecast structured around what is considered to be the "conventional wisdom" regarding fossil fuel markets.[47] These prices for 2020, which include transportation costs to New England, are shown in Table 2-1. In general, the conventional-wisdom forecast assumed the continued development of additional supplies of fossil fuels. Specifically, the forecast assumed the following:

- Relative stability in OPEC nations
- New oil supplies from Alberta tar sands, the former Soviet Union, and ultra-deepwater sources
- Steady worldwide investment in exploration and production
- The gradual development of new natural gas reserves
- Moderate worldwide growth in oil demand
- The development of new U.S. supplies in the Alaska North Slope and Gulf offshore areas

On the basis of these assumptions, the relative prices for fossil fuels are comparable to recent experience.

Table 2-1
Scenario Analysis Fossil Fuel Price Forecasts for 2020, 2006 $/MBtu[(a)]

Natural Gas[(b)]	Residual Oil (0.3% Sulfur)	Distillate Oil	Appalachian Coal	Imported Coal
6.16	7.03	11.93	2.00	2.11

(a) MBtu stands for million British thermal units.

(b) For natural gas, a monthly price profile was developed to reflect typical historical patterns across the year to capture seasonal differences.

[47] Levitan and Associates, Inc. (LAI). *Scenario Analysis Project—Long-Term Forecast of Oil, Natural Gas, and Coal Prices in New England*, (Boston: Levitan and Associates, March 22, 2007).

While electricity prices in the region have consistently been higher than the national average for many decades, more recently, prices have risen significantly.[48] This is, in part, a result of the region's reliance on natural gas—a fuel whose prices have more than doubled from their pre-2000 levels.[49,50] In 2000, gas was used to produce 16% of the region's electricity; in 2006, this percentage had risen to 40%, with gas- and gas-oil-fired power plants setting the price in New England's wholesale energy markets in over 80% of the hours of the year. In the scenarios, the price of natural gas was assumed to vary seasonally, but did not change as a result of differences in the demand for natural gas associated with the various scenarios.

2.1.6 Market and Economic Assumptions

The Scenario Analysis simulations were structured assuming that the markets and supplier bidding were fully competitive, but the analysis did not account for higher prices in congested areas, which tends to bias prices low. Additional assumptions were made about the markets, such as for revenue requirements and clearing prices, to calculate the net revenues that each type of resource could receive and compare each scenario's net revenues with its overall capital and operating costs (see Section 2.2.2). All the economic calculations used 2006 dollars. The market and other economic assumptions are explained more fully in the discussion of economic metrics (Section 3.3.1).

2.2 Technology-Specific Assumptions

In addition to systemwide assumptions, the analysis incorporated a number of assumptions in the following categories specific to each technology:

- Each technology's capacity value, ability to produce electric energy, and operating characteristics
- Emission rates of sulfur dioxide, nitrogen oxides, carbon dioxide, and mercury for units that burn fossil fuels
- Value (or cost) for emission allowances
- Amount of water needed for cooling purposes for some types of major new power plants
- Amount of land needed to site various types of infrastructure, including new supply-side resources and transmission lines for some technologies

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48 Tierney, Susan. *Analysis of Energy Information Administration Form 826 Data*. Presentation to the 100th Massachusetts Restructuring Roundtable, March 30, 2007.

49 See the *2005 Annual Markets Report* (hereafter cited as AMR05) (Holyoke, MA: ISO New England, June 1, 2006), Also see the ISO's *Electricity Cost White Paper* (Holyoke, MA: ISO New England, June 1, 2006). This paper discusses the links between wholesale electric energy prices in New England and the price of natural gas.

50 From 1990 through 1999, wellhead prices for natural gas in the United States averaged $1.92 per thousand cubic feet (cf) of gas; after 2000, annual wellhead prices for natural gas have been considerably higher: $3.68 in 2000, $4.00 in 2001, $2.95 in 2002, $4.88 in 2003, $5.46 in 2004, $7.33 in 2005, $6.42 (estimated) for 2006. *Historical Natural Gas Annual* (Washington, DC: U.S. Department of Energy, Energy Information Administration, 2007), "Table 7: Wellhead Value and Marketed Production of Natural Gas by State, 1967 to 2000." *Natural Gas Monthly* (Washington, DC: U.S. Department of Energy, Energy Information Administration, 2007), "Table 4: U.S. Natural Gas Imports and Exports, 2005-2007."

2.2.1 Availability of Capacity and Ability to Produce Electric Energy

Each type of resource is associated with a *capacity value* (CV) and an *availability factor*. The CV variable generally represents the resource's installed nameplate capacity and is the basis for capacity market payments. The availability factor represents a resource's ability to produce energy and reflects the resource's seasonal and hourly capability, taking into account the resource's planned and forced outages.[51] Except for the scenarios and sensitivity cases that included demand-side resources, the assumptions about the ability of a technology to produce electric energy were based on the availability of the equipment and the technology's fuel source. For the scenarios and cases that included demand-side resources, the amounts that these resources reduced load were based on the system load levels. For this analysis, the availability factors for most generating units reflect industry averages based on recent experience.

2.2.1.1 Treatment of Intermittent Resources

Photovoltaic and wind resources are considered intermittent resources, which affects the availability factors for these resources. In addition to the engineering design and performance of the equipment (e.g., the PV panels and wind turbines), the ability of facilities that use these resources to produce electricity is directly tied to the availability of the sunlight or wind at a specific location, time of day, and season. To account for this intermittency, the model simulated hourly production for these resources. The amount of generic intermittent resources available was calculated consistent with the Forward Capacity Market (FCM) rules for intermittent resources.[52]

Solar PV energy profiles were developed from many years' data on hourly solar measurements taken at two representative sites: Hartford, Connecticut, and Boston, Massachusetts. The profiles for the two sites were then integrated into one representative New England PV site for the modeling of this resource in Scenario #6 (renewables).[53] Solar photovoltaics were assumed to have a summer capacity value of 40% and a winter CV of 5%.[54]

Similar to the PV profile, hourly, monthly, and annual wind energy profiles were developed for two representative New England inland wind sites and three offshore wind sites to model wind as an energy resource in the region.[55,56] Composite monthly profiles were then developed for both the

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[51] A *planned outage* is the planned inoperability of a generator, generally to perform maintenance. A *forced outage* is a type of unplanned outage that involves the unexpected removal from service of a generating unit, transmission facility, or other facility or portion of a facility due to an emergency failure or the discovery of a problem. These problems must be repaired as soon as crews, equipment, corrective dispatch actions, or a combination of all measures can be activated to allow the work to be performed. Both planned and forced outages were considered in the overall production of energy by nonintermittent resources.

[52] The Forward Capacity Market is a wholesale capacity market to encourage investment in demand and supply resources. Under the FCM, the ISO will project the needs of the power system three years in advance and hold an annual auction to purchase the power resources that will satisfy the future regional requirements.

[53] See the *Final Scenario Analysis Modeling Assumptions* (Holyoke, MA: ISO New England, May 21, 2007) (hereafter cited as *Final Assumptions, May 2007*), slide 31. Also see slides 12 and 13 from the March 15, 2007 presentation, *Scenario Analysis Updates on Modeling Inputs and Assumptions: Wind, Photovoltaic, Load Response, and Hydro*.

[54] The solar PV energy profile indicated an effective output as high as 55% at hour ending 1:00 p.m. (i.e., 12:01 p.m. to 1:00 p.m.). Another study shows an effective output ranging from 50 to 65% at peak demand times in New England. See Richard Perez, et al. *Update: Effective Load Carrying Capability of Photovoltaics in the United States*, (Golden, CO: U.S. Department of Energy, National Renewable Energy Laboratory; June 2006).

[55] LAI. *Technical Assessment of Onshore and Offshore Wind Generation Potential in New England* (Boston: Levitan and Associates, Inc. May 1, 2007).

[56] See slides 21–26 in the Final Assumptions, May 2007, for additional information on the assumptions made for the wind profile.

inland and offshore sites. Overall, onshore wind was estimated to have a capacity value of 19% for summer and 41% for winter. Offshore wind was estimated to have summer and winter capacity values of 26% and 47%, respectively. Actual installations of wind resources could have substantially different values.

2.2.1.2 Treatment of Demand-Response and Energy-Efficiency Resources

The Scenario Analysis modeling framework viewed demand-response and energy-efficiency resources similar to generation resources, and the model "dispatched" these "supplies" the same way as generation resources. In reality, however, the system operator does not dispatch demand-response and energy-efficiency resources. Instead, when customers use demand-response and energy-efficiency measures, the result is reduced demand (energy consumption) in the electric system, and the system operator dispatches generation resources to meet the remaining physical load on the system.

The "availability" of some demand-side resources and their ability to reduce customer usage depend, in part, on the technical fit between the demand-reduction measures in place (e.g., high-efficiency air conditioners) and the time(s) of day or season(s) when the affected equipment or appliances typically are used (i.e., winter, when efficient air conditioners are not being used and thus do not reduce electricity usage). It also depends on how well a technology can shift load from peak to off-peak periods. For this analysis, demand-response and energy-efficiency resources represented the aggregate electrical characteristics of many thousands of demand-side resources and not one particular technology.

For this analysis, demand response was modeled as a resource that operates under expected peak-load conditions, reduces only the highest systemwide loads of the year, and qualifies for capacity payments. Energy efficiency was modeled as providing greater outputs at times of highest systemwide demand and smaller amounts during periods of lowest systemwide demand. It was assumed that reduction in demand takes place with no generation turned on "behind the meter," which reduces the net load for the system overall.

2.2.2 Plant Operating Characteristics and Capital Costs

Table 2-2 summarizes the data assumptions used for plant operating characteristics and total plant capital costs for each of the expansion technologies. (Additional information on the fixed and variable costs for the scenario technologies is provided in Section 3.3.1 on the economic metrics used in the analysis.)

Table 2-2
Major Assumptions for Power Plant Operating Characteristics

Technology	Energy Source	Typical Unit Size (Nameplate MW)	Heat Rate (Btu/kWh)[(a)]	Equipment Availability (%)	Capital Costs (2006 $/kW)	Sources[(b)]
Nuclear	uranium	1,080	10,000	90	3,000–5,000	NEI, 2007; Westinghouse, 2007
Coal IGCC	Appalachian coal	600	8,600	80	2,500–3,500	DOE, 2007d; EPA, 2006; EPRI, 2005; MIT, 2007
Coal IGCC with carbon capture[(c)]	Appalachian coal	600	9,750	80	2,900–3,900	EPA, 2006; EPRI, 2005; MIT, 2007; UN, 2005
Natural gas combined cycle	natural gas	400	6,500	90	800–1,000	GE Energy, 2005
Natural gas combustion turbine	natural gas	100	8,500	90	500–700	GE Energy, 2005
Fuel cells[(d)]	natural gas	1	8,000	95	3,500–4,000	Fuel Cell Energy, 2007
Biomass	wood chips	40	14,000	90	2,500–3,500	CT Projects, 2007; NH DES, 2007
Hydro	water	5	N/A	90	3,000–4,000	NE Developer, 2007
Landfill gas	landfill gas	5	10,500	90	2,000–2,500	NE Developer, 2007
Combined heat and power[(d)]	natural gas	5	9,750	90	1,000–1,500	Solar Turbines, 2005
Solar photovoltaic	sun	1	20%[(e)]	98	4,000–6,000	UMASS RERL, 2007
Onshore wind	wind	1.5	N/A	90	1,500–2000	Levitan, 2007b, UMASS RERL, 2007
Offshore wind	wind	3.5	N/A	90	2,000–2,500	Levitan, 2007b, UMASS RERL, 2007

(a) A plant's heat rate is its operating efficiency for converting fuel to electricity. It is the amount of fuel (in Btu) it needs at nameplate capacity to produce one kilowatt-hour of electricity.

(b) See the Table Citations and List of References at the end of the report for complete citation information.

(c) Carbon capture, a measure to control CO_2 emissions, adds to a facility's variable and capital costs. See description that follows.

(d) The fuel cell and CHP distributed generation systems are typically installed at a larger facility (e.g., university, hospital, or hotel). These technologies offer dual benefits of electricity production and the use of the exhaust heat for air and water heating, process steam, and other applications. The heat rates and capital costs of these technologies reflect only the production of electricity and not the use of the exhaust heat.

(e) PV conversion efficiency is a measure of the conversion of sunlight to AC power.

The operating characteristics and capital costs for existing power plants were based on actual data for each type of plant, as reflected in the RSP06 database.[57] To determine these characteristics and costs for new demand-side technologies and power generation resources added in each of the scenarios, the analysis incorporated information from published reports, manufacturers, developers, and other sources. The cost assumptions for energy efficiency and demand-response measures were developed from historical demand-side program costs, as reported by the states or to them from the utilities implementing such programs.

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[57] ISO New England Web site page, "Regional System Plans 2006" (Holyoke, MA: ISO New England, 2006).

Clearly, adding new gas-fired power plants, nuclear capacity, demand-side resources, and so forth has associated investment costs. The analysis assumed that under all scenarios, the regional natural gas delivery system underwent a baseline expansion to accommodate future gas needs in the region. A common fuel-supply assumption across all scenarios and all sensitivity cases was that the Canaport LNG project in St. John, New Brunswick became commercialized and able to satisfy the incremental gas demands associated with Scenario #1's "queue" mix of gas-fired resources.[58] In addition, because it was assumed that all dual-fuel combustion turbines within the queue mix have the ability to run on oil rather than natural gas during the core heating season, November through March, it was also assumed that pipeline improvements were not needed to serve these new peaking generators.

The capital costs for new energy resources were analyzed as cost ranges reflecting the addition of each supply-side or demand-side technology, including any load-serving entity costs.[59,60] For all but Scenario #7 (the import scenario), it was assumed that capital investment was made in New England associated with the electric power resource itself, that is, the nuclear capacity, the gas-fired generation units, the advanced coal-fired power plants, the demand-side measures, or the renewable power facilities.

Incremental capital costs for the expansion resources from neighboring systems supplying the imported power in Scenario #7 and conceptual transmission in neighboring regions were not included per se because the types of resources that would supply this power and the extent to which any such resources would be built for other purposes in combination with supplying exports to New England were not known. This is not a reflection that the costs for transmission and production facilities would be zero, only that no reliable estimates are currently available. For example, neighboring systems may build or advance the in-service dates of new facilities for New England's use at New England's cost. Alternatively, system improvements may be planned solely for use by neighboring systems but may have the ancillary benefits of improving the export capability to New England.

It was assumed, however, that any new resources were priced according to what the New England market would bear, or below the cost (operating and investment) of the marginal source of power in the region. It was also assumed that such imports needed delivery infrastructure built in New England to accommodate the importation of energy. Therefore, Scenario #7 included transmission costs on the U.S. side of the border. It is also reasonable to assume that under this scenario, the region incurred other generation and transmission costs. The ISO will continue to coordinate with Canadian entities in Quebec and the Maritimes to better understand the planned physical expansion of those systems that may develop additional infrastructure consistent with their economic interests and tariff obligations.

IGCC technologies that capture and permanently store (*sequester*) carbon were assumed to release only 10% of the CO_2 emissions into the atmosphere that are released by facilities without carbon capture.[61] Scenario #4 (coal IGCC) assumed no carbon capture and sequestration. However, a sensitivity case for this scenario accounted for controlling carbon emissions by capturing,

[58] The Canaport LNG facility is being developed jointly by Respol and Irving Oil Company.

[59] Certain capital costs (e.g., advanced metering equipment) for certain demand-side options were not included in these analyses.

[60] A *load-serving entity* secures electric energy, transmission service, and related services to serve the demand of its customers.

[61] Several possible methods exist for sequestering carbon. They include the geological storage of CO_2 (deep injection into the ground), ocean storage, biological processes, and afforestation, which is a current practical option being conducted by many companies around the country. In 2003, the top 10 U.S. companies in this field sequestered about eight million tons of CO_2 mainly through forestry practices. (See *Carbon Sequestration Reporting to the EIA* (U.S. Department of Energy, Energy Information Administration) at the Planet Power Web site.

transporting, and sequestering CO_2 emissions (see Section 3.2.6). This sensitivity case assumed 90% carbon capture and that ocean sequestration is possible (although in general, it is not yet economically available). Higher plant capital costs (+400 $/kW) for the coal IGCC plants' capture of CO_2 and a 13% increase in the plant's heat rate were also assumed. A sequestration operating cost of $25/ton of CO_2 was assumed for the carbon transportation, monitoring, and ocean storage.[62]

2.2.3 Air Emissions Regulations and Assumed Emission Rates and Values

Environmental impacts from generating plants, particularly carbon dioxide, sulfur dioxide, nitrogen oxides, and mercury released from coal and oil-fired facilities, are a continuing issue in the region. Current federal and regional regulations and those under development will require existing as well as new generators to continue to reduce these pollutants in the timeframe of this analysis. These regulations include the U.S. Environmental Protection Agency (EPA)'s Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) and state implementation of these; the multi-state Ozone Transport Commission (OTC)'s effort to have OTC states adopt High Electric Demand Day (HEDD) NO_X emission-reduction strategies; and the 10-northeastern-state Regional Greenhouse Gas Initiative (RGGI).[63]

Although total year-round emissions of NO_X are significant, NO_X emissions typically are higher on days with high electricity use when often many peaking units are run to produce power for short periods of time. The HEDD strategy, which only affects Connecticut in New England, aims to have states reduce NO_X emissions associated with the operation of certain electric generating units only.

RGGI is a CO_2 cap-and-trade program under development and implementation that will require electric power generators in RGGI states to limit and reduce CO_2 emissions from 2009 to 2018. Regulated power plants in RGGI states will be able to comply in a number and combination of ways, as follows, for example:

- Buying new CO_2 allowances from RGGI sources, auctions, or in the marketplace (above any number received for free by a state)
- Using previously banked allowances
- Using greenhouse gas offsets up to a maximum percentage, depending on the CO_2 allowance price
- Redispatching power plants to burn fossil fuel (or no fuel) more efficiently
- Switching the type of fuel used
- Adding back-end controls to reduce carbon (when such technological capabilities evolve in the future)
- Increasing low-emitting imports
- Relying on a combination of measures

[62] See *IPCC Special Report on Carbon Dioxide Capture and Storage* (United Nations Intergovernment Panel on Climate Change, September 24, 2005).

[63] Information on the CAIR and CAMR is available online at http://www.epa.gov/interstateairquality/ and http://www.epa.gov/camr/, respectively. Information on the HEDD strategy is available at http://www.otcair.org/document.asp?fview=Formal%20Actions#. Information on RGGI is available at and http://www.rggi.org.

The Scenario Analysis did not explicitly model meeting these regulations but produced emission estimates to show the relative differences among the scenarios and sensitivities. Because the ways in which existing generators will comply with these regulations are unknown, the Scenario Analysis assumed that all the generating units in the year of the analysis (beyond 2020 to 2025) generated emissions at their current rates; estimating these for the future period would be difficult and would not significantly influence the relative differences among the scenarios that are affected most by the added generation resources.

2.2.3.1 SO_2, NO_X, and CO_2 Emission Rates and Emission Values

Table 2-3 shows the emission rates assumed for SO_2, NO_X, and CO_2 for the new generating resources modeled in the analysis. The emission rates for existing power plants were principally based on data from U.S. EPA databases.

Table 2-3
Emission Rate Assumptions for 2020

Technology	Unit Size (MW)	SO_2 (lbs/MBtu)	NO_X (lbs/MBtu)	CO_2 (lbs/MBtu)	Reference[a]
Nuclear	1,080.0	none	none	none	NEI, 2007; Westinghouse, 2007
Coal IGCC[b]	600.0	0.0300	0.0100	210.0	DOE, 2007d; EPA, 2006; EPRI, 2005; MIT, 2007
Coal IGCC with carbon capture[b]	600.0	0.0300	0.0100	21.0	EPA, 2006; EPRI, 2005; MIT, 2007; UN, 2005
Combined cycle[c]	400.0	0.0006	0.0100	120.0	GE Energy, 2005
Combustion turbine	100.0	0.0006	0.0300	120.0	GE Energy, 2005
Fuel cells	1.0	0.0006	0.0088	120.0	Fuel Cell Energy, 2007
Biomass	40.0	0.0200	0.0750	170.0[d]	CT Projects, 2007; NH DES, 2007
Small hydro	5.0	none	none	none	NE Developer, 2007
Landfill gas	5.0	0.0200	0.0300	0.0[e]	NE Developer, 2007
Combined heat and power	5.0	0.0006	0.0140	120.0	Solar Turbines, 2005
Solar photovoltaic	1.0	none	none	none	UMASS RERL, 2007
Onshore wind	1.5	none	none	none	Levitan, 2007b; UMASS RERL, 2007
Offshore wind	3.5	none	none	none	Levitan 2007b; UMASS RERL, 2007

(a) See the Table Citations and List of References at the end of this report for complete citation information.

(b) The emission rates from coal IGCC plants typically are lower than the emission rates for existing coal plants.

(c) New combined-cycle plants were assumed to be more efficient than existing facilities; thus, emission rates for the new facilities were assumed to be lower than for the existing fleet.

(d) The CO_2 emitted from biomass facilities fueled by sustainably harvested biomass is balanced over time by the CO_2 that is sequestered by growing the fuel, which is why the biomass is considered to be *carbon neutral*.

(e) Burning landfill gas generates CO_2 emissions, but greenhouse gas emissions are released from landfills even without the production of electricity, whether by flaring of the gas or by the direct emission of greenhouse gases more potent than CO_2.

While SO_2 and NO_X emissions from electric power generators have been decreasing in the region directly due to compliance with environmental regulations, total CO_2 emissions have been increasing. Under RGGI, starting in 2009, the New England states' allocation of the 10-state RGGI cap will be a 55.8 million ton CO_2 emission allowance. Within the 10-state RGGI region, fossil-fuel power generators that are 25 MW and larger will need to reduce their overall emissions consistent with this regional CO_2 cap. By 2018, the RGGI cap will decrease 10%, for which the New England states will have a 50.2 million ton allowance. The Scenario Analysis generated results for total CO_2 emissions for the six-state New England region and compared the results with a level of CO_2 emissions equivalent to the 50.2 million ton allocation under the assumptions for each scenario.[64]

Opting to buy emission allowances as a way to comply with environmental regulations adds to a power generator's variable costs, which affects its unit dispatch costs and generation output as well as the system's overall fuel mix. Having this regional cost adder also affects the value of fossil fuel generation from outside the region and non-emitting generation from within the region. Table 2-4 shows the assumptions used in this analysis for emission values in 2020, which were used to determine the dispatch cost adders for each type of generating technology.

Table 2-4
Emission Value Assumptions

Emission	Emission Value (2006 $/ton)	Source[a]
SO_2	969	DOE, 2006
NO_X	2,345	DOE, 2006
CO_2	3, 20, and 40	Synapse Energy, 2006

(a) See the Table Citations and List of References at the end of the report for additional citation information.

The $20 CO_2 allowance value represents the base-case assumption.[65] These values will principally be determined by the auctions that the RGGI states are planning to conduct. Similar to SO_2 and NO_X allowances today, these CO_2 allowance values will be reflected as adders in the generators' bid prices. This was modeled in the Scenario Analysis as an adder to the fuel costs.

2.2.3.2 Emission Rate Adjustments for RGGI Requirements

The RGGI requirements exempt units less than 25 MW in size, existing biomass units that use more than 50% biomass fuel, and new biomass plants that use at least 95% biomass as fuel. Since the Scenario Analysis emissions analysis reflected the total New England generation system, which includes these types of units, the CO_2 results needed to be adjusted to enable an "apples-to-apples" comparison of each scenario's CO_2 emissions with the RGGI CO_2 emission allocation for New England. Thus, for each applicable scenario and sensitivity case, the total CO_2 emissions for the smaller plants and the biomass plants were subtracted from the total emission results. This level of CO_2 emissions was compared with an expected cap level for the New England States for around 2020, which is a 10% decrease from the initial cap for 2009 to 2014.[66]

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64 Additionally, the New England Governor's/Eastern Canadian Premiers (NEGC/ECP) Climate Action Plan (August 2001) has broader goals for CO_2 emission reductions. This plan, adopted in 2001 by the NECG/ECP, includes a cross-sector goal of reducing all greenhouse gas emissions to 10% below 1990 levels by 2020, and a longer-term goal of reducing regional greenhouse gas emissions sufficiently to eliminate any dangerous threat to climate. That plan also presented two interrelated electricity sector goals: "By 2025, reduce the amount of CO_2 emitted per megawatt-hour of electricity use within the region by 20% of current emissions;" and "By 2025, increase the amount of energy saved through conservation programs (as measured in tons of greenhouse gas emissions) within the region by 20% using programs designed to encourage residential, commercial, industrial and institutional energy conservation."

65 The stakeholders suggested the ISO use CO_2 allowance prices from the Synapse Energy report, *Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning*. (Cambridge, MA: Synapse Energy Economics, June 8, 2006). Also note that the model simulations used a fixed carbon price. It did not apply a cap and thus did not explicitly model a hard cap-and-trade program.

66 Although the use of offsets could help meet the RGGI allocation for New England, to be conservative, the analysis assumed that offsets would not be used.

This analysis was based on emissions reported in the NEPOOL Generation Information System (GIS) from 2005 and 2006 to estimate the CO_2 emissions from units less than 25 MW, plus the emissions from biomass units.[67] These GIS emissions were assumed to be the same for the RGGI-exempt units in the scenarios. Therefore, 5 million tons was subtracted for these non-RGGI units in all the scenarios except Scenario #6 (renewables). In this scenario, an additional 12 million tons was subtracted for a total of 17 million tons because 675 MW of biomass units and 675 MW each of fuel cell and CHP units under 25 MW were added in this scenario.

2.2.3.3 Mercury Emission Rates

The analysis of the coal plants simulated mercury emissions on the basis of Appalachian coal having a mercury content of 5.7 lbs/trillion Btu (TBtu) before controls.[68] Since state mercury regulations are focusing on a 90% removal requirement, it was assumed that the "actual" amount of emissions was about 10% of the amount simulated for the scenarios.

2.2.4 Cooling Water Requirements

Because it was assumed that the Clean Water Act (CWA) will require new large generating plants to use cooling towers, the Scenario Analysis developed assumptions for the rate of cooling water use (gallons/minute) for these power plants.[69]

2.2.5 Acreage Needed and Costs for Siting Infrastructure

Estimates were also made for the amount of acreage needed to develop new generation and transmission facilities for the various types of resources added in the scenarios (i.e., acres per MW for generation capacity, miles per line, total lines, and cost per mile for transmission), generally excluding public use of these areas. Similar to transmission rights-of-way, however, the analysis recognized that wind sites might allow public use, such as for farming or recreation (i.e., boating and fishing in the water between offshore wind turbines). The ISO and the regional transmission owners developed conceptual generic costs for new transmission lines and substations needed to integrate new generation into each of the scenario's unique system structure, which were used to make assumptions for overall transmission costs.

The analyses assumed that central-station generating units (e.g., gas-fired power plants, nuclear plants, advanced coal plants) were located relatively close to the load center and needed less significant transmission investments than remote sources of electricity (i.e., onshore and offshore wind and imports from neighboring systems). The likely economic, reliability, and environmental trade-offs between locating generation in load centers and improving transmission was not a focus of this analysis. Since it was assumed that additional transmission was not needed to support demand-side resources, no additional land use was assumed for this scenario.

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[67] Information about NEPOOL's Generation Information System is available online at http://www.nepoolgis.com/.

[68] LAI Feb 2007 fuel-price forecast: Coal has been estimated to contain from 2.7 to 5.5 lb/TBtu depending on its source. Appalachian coal was assumed for Scenario #4 (coal IGCC). (See the Final Assumptions, May 2007.)

[69] U.S. EPA, Cooling Water Intake Structures—Clean Water Act §316(b), Phase I—New Facilities. This section addresses the location, design, construction, and capacity standards for cooling water intake structures at new electric generating plants and manufacturers that use 25% or more of their intake water for cooling and withdraw more than two million gallons per day (MGD) from U.S. waters. New facilities with smaller cooling water intakes will still be regulated on a site-by-site basis. Additional information is available online at http://www.epa.gov/waterscience/316b/phase1/. Accessed May 8, 2007.

Section 3
Methodology

This section describes the analytical techniques and tools used to simulate and study the different scenarios. These tools modeled regional electricity production, the costs to produce and purchase it, and some of the potential environmental impacts, taking into account the existing fleet of power plants and the new resources each scenario added.

For each scenario's set of available new resources (with their various operating characteristics), the simulation "dispatched" power plants to meet different levels of customer demand in every hour of the year being analyzed. These simulations established a "common-assumptions case" for each scenario based on the common assumptions discussed in Section 2 plus a wide array of additional information and assumptions about how the electric power system "performed" from an economic, environmental, and reliability standpoint.

As requested by stakeholders, the ISO ran a series of sensitivity analyses that varied the parameters used in the common set of assumptions, thus capturing a wider array of inputs and generating a broader set of results for each scenario. Each sensitivity analysis ran additional simulations by varying, for example, the assumptions regarding fossil fuel prices, the mix of new generation and demand-side resources, unit retirements, costs of CO_2 emission allowances, and imports available from neighboring regions.

3.1 Tools for Analyzing the Scenarios

The first part of the analytic process involved conducting three types of analyses for each scenario, as follows:

- Simulations of production costs
- "Post-processing" calculations that the initial simulations could not generate directly
- "Operable capacity" analyses of various types of resources, which indicate the extent to which the region depends on a given level of resources in the face of a potential disruption of the fuel supply

3.1.1 Production Simulation Modeling Using the IREMM Model

To simulate the dispatch and estimate production costs for the New England electric system, the ISO used the Interregional Electric Market Model (IREMM), the same model previously used in the ISO's annual regional system planning process. The model provides production costs for each resource and aggregates total systemwide costs.

For each hour of the year being studied (assuming a fully competitive market and supplier bidding), IREMM simulates how power plants are called on in economic sequence to operate for reliably meeting the demand for electricity. Using assumptions about each power plant's heat rate, the type of fuel consumed, the costs for fuel, outage patterns for maintenance and repairs, and other data on operating performance and costs, the model dispatches resources from lowest to highest cost to meet each hour's demand.[70] IREMM models the dispatch of the power system around the clock for the total 8,760 hours of a single future year, simulating how the system can meet the variation in customers' demand each day and the peak demand during the summer and winter periods.[71, 72]

For the scenarios that reflected the addition of new supply-side generating resources (e.g., all scenarios except Scenario #2, which added 5,400 MW of demand-side resources), the model added power plants to the system's existing fleet and 2,600 MW of resources reflecting the fuel mix in the ISO's Generator Interconnection Queue. The model does not "dispatch" wind turbines and solar photovoltaics in the same way as other power plants. Because these types of facilities deliver power when the "fuel" or energy source (e.g., the wind or the sunshine) is available, the model injected a specific amount of electric energy into the grid according to preset profiles that reflect the amount of wind or sunshine in different hours and months of the year. (See Section 2.2.1 for more information on how outputs were reduced to account for forced and planned unit outages and the availability of sun and wind capacity.)

For Scenario #2, which reflected the system's response to demand-side resources that lower customer requirements, the model captured reductions in systemwide customer demand for every hour of the year instead of adding more generating resources. This aggregate reduction in customer demand for this scenario reflected an amount of demand response and energy efficiency that reduces hourly energy demand by newly installed efficiency measures. Thus, demand-side measures were input directly into the model to represent hourly profiles of 2,700 MW of energy efficiency and 2,700 MW of demand response available at the time of a 35,000 MW systemwide load. The scenario assumed that energy efficiency "supplied" (i.e., reduced energy demand by) a total of 18 million MWh (megawatt-hours), or 18 terawatt-hours (TWh), of electric energy.[73]

Imports of hydro and other low-emission resources (Scenario #7) were modeled to account for the transfer of a high amount of electricity imports when systemwide electric energy costs in New England would be high and a low amount of imports during lower-cost, off-peak systemwide load periods.

3.1.2 Post-Processing Calculations

While the IREMM model results provide information about the cost, reliability, and emissions associated with each scenario's production of electric energy, the results of the model do not include information about a number of other economic metrics. These other metrics include the capital costs needed for expanding supply- and demand-side resources; the costs to cover incremental transmission, distribution, and fuel (natural gas) delivery infrastructure the scenarios needed; and the annual market revenues new resource projects obtained from the wholesale energy markets. The

[70] Generating units and other resources are dispatched in *economic merit order*. That is, the dispatch process takes into account the relative costs of primary and alternate fuels at individual units and across generating units and unit heat rates. To model unit unavailability, planned and forced outages are accounted for as unit *deratings* (i.e., reductions in unit capability).

[71] In general, the customer demand curve shows rapid increases in usage (electric load) during the morning due to the start-up of electric heat or cooling and other usage for office buildings. Weekends tend to show lower curves. The demand curve varies over the course of the year as well. The daily peaks in the fall and spring seasons are lower in general, for example, and higher on hot summer days when the temperature and air-conditioning usage is the highest.

[72] The Scenario Analysis load curve under the common set of assumptions reflects the same shape as that used in the ISO's RSP06, expected for calendar year 2015.

[73] One terawatt is equivalent to 1,000 gigawatts (GW), one million megawatts, one billion kilowatts (kW), and one trillion watts (W).

IREMM simulations also did not account for physical resource needs for land and water use or adjust CO_2 emission values. Post-processing calculations were conducted to provide and compare these data.

3.1.3 Operable Capacity Analysis of Various Types of Resources

Using a methodology similar to RSP06, the ISO conducted an analysis designed to indicate the extent to which the region would depend on power production capacity that uses a particular type of fuel.[74] This analysis, known as an *operable capacity analysis* (OCA), evaluates the ability of the system to reliably serve seasonable peak demand during periods of disruption to specific fuel types.

For each fuel type, the analysis specifically identifies *operable capacity margins* (i.e., the amount of resources that must be operational to meet peak demand plus operating reserve requirements) under peak-load conditions for the summer and the winter. Positive operable capacity margins indicate that the system has sufficient resources using other fuel types to provide a sufficient operable capacity. Negative margins indicate the need for supplemental dual-fuel capabilities, firm fuel supplies, the increased ability to import power from neighboring systems, or other resources.

This analysis simulated a hypothetical and temporary loss of specific fuel types used in each scenario to estimate the net systemwide capacity that was available under the specific scenarios. It also estimated the minimum amount of electricity each fuel type needed to generate to maintain the reliability of system operations. For each of the scenario's major fuel types, the analysis identified either a surplus or deficiency for reliably meeting summer and winter peak loads.

3.2 Sensitivity Analyses

IREMM was also used to conduct the sensitivity analyses. These analyses varied the assumptions used in the simulations, taking into account different inputs appropriate to each different scenario and sensitivity parameter. Similar to the simulations under the common set of assumptions, for each sensitivity run, the model responded to the changes in demand, generating resources, or a combination of both and "dispatched" them given the economics of each sensitivity's conditions. Counting the seven core scenario runs for the common set of assumptions, 52 simulations, as shown in Table 3-1, were conducted for the Scenario Analysis.

[74] RSP06, Section 6.3

Table 3-1
The Seven Core Scenarios and Associated Sensitivity Analyses

		A	B	C	D	E	F	G	H	I	J	K
									Miscellaneous Sensitivity Cases			
	Scenarios — incremental 8,000 MW. All cases have the same 2,600 MW of resources reflecting proposals in the ISO queue as of 9/30/06.	**Common Assumptions**	**Low Gas-Fuel Prices**	**High Gas-Fuel Prices**	**Replace 3,500 MW of the Scenario Technology with 1,750 MW of Energy Efficiency (EE) and 1,750 MW of Demand Response (DR)**	**Retire 3,500 MW and Replace with Scenario Technology**	**Low Carbon-Allowance Prices**	**High Carbon-Allowance Prices**	**Decreased Imports of Low-Emission Resources (−7 TWh)**	**Replace 2,700 MW of EE with 2,700 MW of DR (5,400 MW of DR, or Double DR)**	**Replace 2,700 MW of DR with 2,700 MW of EE (5,400 MW of EE, or Double EE)**	**For Coal with Carbon Sequestration**
1	**Queue Mix —** combination of currently proposed resources; 5,400 MW blend reflecting the fuel mix exhibited recently by the market	X	X	X	X	X	X	X				
2	**Demand-side resources —** an additional 2,700 MW of DR and 2,700 MW of EE	X	X	X	(a)	X	X	X		X	X	
3	**Nuclear —** 5,400 MW	X	X	X	X	X	X	X				
4	**Advanced technology coal (IGCC) —** 5,400 MW without carbon sequestration	X	X	X	X	X	X	X				X
5	**Natural gas (combined cycle) —** 5,400 MW	X	X	X	X	X	X	X				
6	**Renewables —** 5,400 MW, including a combo of on- and offshore wind, hydro, biomass, LFG, CHP, fuel cells, PV; 1/8 each	X	X	X	X	X	X	X				
7	**Increased imports of hydro and other low-emission resources —** 30 TWh of imports	X	X	X	X	X	X	X	X			

(a) Case 2D is the same as case 2A.

For all the scenarios, the following sensitivities were run:

- Higher and lower fuel-price forecasts
- Capacity retirement and replacement with the technology featured in the scenario (retirement case)
- Higher and lower prices for carbon emission allowances

Several of the scenarios had specific sensitivity runs, as follows:

- For all but Scenario #2 (demand-side resources), a sensitivity case was run that added additional demand response and energy efficiency instead of the technology featured in the scenario.
- A sensitivity case for Scenario #7 (imports) decreased the level of low-emission imports of electric energy but kept the same 5,400 MW capacity.
- For Scenario #2 alone, two sensitivity cases were run that interchanged the levels of demand response and energy efficiency.
- A sensitivity case for Scenario #4 (coal IGCC) considered the increased capital and operating costs associated with carbon sequestration.

3.2.1 Fuel-Price Sensitivity Cases

For all scenarios, two sensitivity cases decreased and increased the fuel prices upon which the “conventional wisdom” fuel-price forecast (as described in Section 2.1.5) was based (see columns B and C in Table 3-1). Natural gas prices were twice as high in the high gas-price case as they were in the common-assumptions case. The price for distillate fuel oil was maintained at a level above that of the (doubled) gas price, and the price for residual fuel oil was kept at a price lower than natural gas. Coal prices did not change from the initial case. The intention in developing this outlook was to show the range of impacts when the relationship between natural gas prices and heavy oil prices shift and natural gas prices become much less competitive compared with heavy oil prices.

In contrast, natural gas prices in the low-gas-price case were one-half the level shown under the common-assumptions case. The price for distillate fuel oil was maintained at a level greater than the price of residual fuel oil, with both prices being greater than the (halved) price of natural gas. In essence, the coal and oil prices (for both distillate and residual oils) remained the same in this case as in the common-assumptions case.

3.2.2 Sensitivity Cases for Reducing Demand and Rebalancing Demand Response and Energy Efficiency

Another set of sensitivity cases analyzed the scenarios under a system that needed less than 5,400 MW of each scenario’s core technology as a result of the availability of stronger demand-side resources during the forecast year (see column D in Table 3-1). For this set of cases, it was assumed that only 1,900 MW of the core scenario technology needed to be added to the 3,500 MW of demand-side measures (i.e., 1,750 MW of energy-efficiency measures and 1,750 MW of demand-response measures). These sensitivity cases showed further trade-offs associated with adding supply-side technology compared with demand-side measures.

Two miscellaneous cases were run for Scenario #2. One case doubled the amount of demand response in lieu of energy efficiency (called “Double DR;” see column I in Table 3-1). Specifically, this case included 5,400 MW of demand response (i.e., used for peak shaving only) and no energy efficiency. The second sensitivity case doubled the amount of energy efficiency in lieu of demand response (called “Double EE;” see column J in Table 3-1). The second version solely included 5,400 MW of new energy efficiency measures (as opposed to 2,700 MW of energy efficiency and 2,700 MW demand-response measures).

3.2.3 Unit Retirement Sensitivity Case

A “retirement” sensitivity case (column E in Table 3-1) was analyzed for every scenario. For this case, in addition to the original assumed incremental addition of 8,000 MW of new capacity, new scenario-technology capacity was added to counteract the effects of retiring 3,500 MW of generating capacity that exists as of 2007. In these sensitivity cases, a total of 11,500 MW of new capacity was added, of which 2,600 MW reflected the common mix in the Generator Interconnection Queue (i.e., a common-set assumption). All the remaining new capacity was composed of the scenario’s core technology. For the case of imports, the capacity of the transmission interconnections was increased to 8,900 MW, and the amount of imported energy was increased from 30 to 50 million MWh.

3.2.4 Carbon-Allowance Price Cases

For this analysis, two sensitivity cases were run for each scenario to capture low and high prices for the carbon-emission allowances (e.g., $3/ton and $40/ton, respectively; see columns F and G in Table 3-1). The low-price case represents the availability of many allowances when few were needed; the high-price case represents the case in which the allowances were in greater demand.

This sensitivity also serves as a proxy for changes in prices for other emission allowances.

3.2.5 Decreased Imports Sensitivity Case

For Scenario #7 (imports), a sensitivity was run in which only 23 million MWh rather than 30 million MWh was imported (column H in Table 3-1). This case was run to account for importing a low amount of electricity during lower-cost, off-peak systemwide load periods. Under this case, the same amount of transmission infrastructure was needed in the region as for the other scenarios to accommodate the maximum import level of 5,400 MW, despite the decreased availability of energy imports.[75] Because the capital costs of the expansion resources and the conceptual transmission cost estimates for neighboring systems are unknown, only generic transmission cost estimates within New England, and not those in Canada and New York, were incorporated in the analysis of this sensitivity case (see Section 3.3).

3.2.6 Carbon Sequestration Sensitivity Case

A sensitivity case for Scenario #4 (coal IGCC) accounted for controlling carbon emissions by capturing, transporting, and sequestering CO_2 emissions (see Section 2.2.3 and column K in Table 3-1). This case assumed that the facilities captured then transported and sequestered 90% of the CO_2 produced by generating the 5,400 MW of power. This case also assumed that capital and

[75] This case is sometimes referred to as the “Hydro 23” case in accompanying Web site materials.

operating costs increased by \$400/kW and \$25/ton of CO_2, respectively, compared with the costs for Scenario #4 under the common set of assumptions.

3.3 Metrics for Comparing the Scenarios

On the basis of the power plants dispatched for each scenario and sensitivity case, the post-processing calculations, and the operable capacity analysis, the ISO generated a variety of economic, reliability, and environmental metrics, as summarized in Table 3-2. Because of the inherent limitations of an analysis like this, all the metrics are tied—directly and indirectly—to the performance of the electric power system and larger societal issues. Thus, other benefits and costs of the different scenarios' externalities may exist that are not reflected in these metrics. These could include factors such as job creation (or losses), tax implications, public health and safety, siting and "not-in-my-backyard" (NIMBY) issues, life-cycle environmental impacts, and others.

Table 3-2
Summary of Metrics for Comparing the Scenarios

Economic[a]	Reliability	Environmental
Systemwide production costs[b] (billion \$)	Systemwide energy mix (MWh; % MWh by fuel)	Total systemwide emissions of SO_2 and NO_X (1,000 tons) and CO_2 (million tons)
Energy supply duration curves for clearing price	Systemwide capacity mix (MW by fuel)	Total systemwide NO_X emissions for the 10 highest peak-load summer days (tons)
Annual revenue requirements (ARR) for expansion resources[c] (billion \$; \$/kW-year)	Total units of fossil fuel burned (quadrillion Btu consumed; MWh of production)	Total systemwide emissions of CO_2 (million tons)
Net wholesale electric energy market revenues for expansion resources[d] (million \$; \$/kW-year)	Exposure to fuel-supply disruption (MW) (operable capacity analysis)	CO_2 emissions compared with RGGI allocation (million tons; compliance/noncompliance)
Load-serving entity expenses for wholesale electric energy based on hourly New England clearing prices (billion \$; \$/MWh)		Mercury emissions (lb)
Generic capital costs for expansion (\$/kW)		Cooling water use (gal/minute)
Generic transmission expansion costs (\$/scenario; \$/MWh)		Amount of incremental land used (acres)
Generic distribution expansion costs (\$/MWh)		Renewable energy contribution (MWh;% MWh)
Costs for generic expansion of gas delivery system (\$)		

(a) All the economic metrics used 2006 dollars.

(b) The systemwide production cost is the sum of the annual production costs (i.e., the fuel and emissions-related operating costs) for every resource to produce power in each hour of the simulated year.

(c) The annual revenue requirement (capital cost times the annual revenue requirement rate) captures all non-fuel-related costs, including the recovery of capital costs, other operating costs, taxes, and other expenses.

(d) Net wholesale electric energy market revenues are equal to revenues from the wholesale electric energy market minus the costs of production and including fuel costs and the costs for environmental emission allowances. For this study, variable operating and maintenance expenses (which are normally relatively small compared with production cost) are captured as part of the annual revenue requirement.

3.3.1 Economic Metrics

The focus of the economic metrics in the Scenario Analysis was to provide comparable information on the costs and revenues for each technology for a single year. One metric provides insights about the extent to which net revenues from the wholesale electricity markets support investment in a particular investment. Another metric shows the potential expenses LSEs have for wholesale purchases of electricity and the relative scenario expenses for electric energy, capacity, transmission, and distribution. A full economic analysis of technology expenses and revenues or of the market prices consumers face is more difficult because it introduces additional unknowns, such as what assumptions to make about such factors as utility ratemaking, inflation, the year-to-year variation in the price of fuels used to generate electricity, weather, and other factors that affect the full costs of delivering power to consumers. Taken together, the metrics provide general indications of the comparative economics of the different technologies, not complete answers about what consumer electricity costs will be if one technology outcome is chosen over another.

3.3.1.1 Annual Revenue Requirements and Net Wholesale Energy Market Revenues for Expansion Resources

Resources must recover their fixed and variable costs to be economical. The extent to which a plant covers its costs is based on the plant's revenues from the wholesale electricity markets and other revenue streams, as described below.

Fixed costs. Fixed costs include debt service, required return on and of investment, depreciation, taxes, labor, and maintenance expenses. A plant's capital costs, as discussed in Section 2.2.2, are fixed costs.

Annual revenue requirement. A plant's *annual revenue requirement* (ARR) is the amount of revenue the plant owner needs to cover the plant's fixed costs that year. For this analysis, the ARRs for all the expansion resources were based on 100% of each technology's nameplate capacity value (see Sections 2.2.1 and 2.2.2) and were assumed to vary from 15% to 25% of the generic capital costs for the expansion technology. ARRs for electric transmission and the natural gas system were assumed to be between 18% and 22% of the installed capital costs.

Variable costs. Supply-side technologies typically have *variable costs* associated with the cost of production. These include costs for fuel, environmental emission allowances, and other, relatively small costs, such as some operating and maintenance costs, which were not accounted for in the Scenario Analysis. For this analysis, demand-side resources, which were assumed to have no variable costs, and supply-side technologies were both modeled as resources to meet load in any given hour. Thus, to ensure that demand-side resources received the same analytical treatment as supply-side resources, the model "dispatched" demand-side technologies at zero variable cost to the extent that these resources were assumed to be available.

Net revenues. The revenue stream from operating a resource is known as *net electric energy market revenues*. For each resource, these net revenues equal the resource's gross wholesale electric energy revenues minus its production costs, including variable fuel and emission allowance costs. For this analysis, the net revenues for the demand-side resources equaled the revenues in the energy market minus zero variable costs. For the given amount of reduced energy consumed, this "energy payment" was assumed to be available to compensate the entity that provided the demand-side resource.[76]

Cost recovery. The greater the resource's wholesale electric energy market revenues compared with its production costs (i.e., the greater its net energy revenues), the more these revenues help recover the resource's capital investment and other fixed costs. When a particular technology's net energy revenues are greater than its ARR, investing in this technology might be more likely because it is economical.

In general, when a gap exists between the net electric energy market revenues and the ARR for a particular type of resource, other means of support may be needed to induce investment in this resource. In New England, other sources of support could include payments from the Forward Capacity Market (assumed for this analysis to clear within the range of $4.50 to $10.50/kW-month); the provision of ancillary services; tax benefits (such as accelerated depreciation and production tax credits for renewable energy projects); sales of emission allowances; Renewable Energy Certificates (RECs); "clean" energy fund subsidies; tax credits; long-term purchased power agreements for electric energy, capacity, or both; rate basing of capital cost; or other monetary streams that value certain attributes of the power resources.[77] The narrower the gap between a power supplier's net energy revenue and the total of its fixed plus variable costs (its ARR), the less "other revenues" it will need to stay in the market.[78]

3.3.1.2 Clearing Prices and Load-Serving Entity Energy Expenses

Another cost-related metric is the load-serving entity wholesale cost that drives the consumers' cost of electricity. An LSE typically pays costs related to the energy markets, as well as any other costs (e.g., capacity and ancillary service costs). LSEs would also charge end users for transmission-related and distribution system costs.[79]

Annual average prices for wholesale electric energy reflect clearing prices for this energy in the New England wholesale energy markets. For each hour, the clearing price reflects the production costs of the last generating unit dispatched to meet load requirements in that hour. In general, clearing prices tend to rise during on-peak hours when generating units with higher production costs and lower efficiency are dispatched. Conversely, in the hours during which demand is the lowest (e.g., at night, or during weekends in the spring and fall), clearing prices may drop, reflecting the relative efficiency and lower fuel prices of the plants on the margin. This analysis assumed that locational differences in

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[76] Although not exactly how these resources actually behave, when consumers pay less total energy costs due to lower energy use, this approach is a reasonable representation of how entities that adopt energy efficiency get compensated for their investment. In effect, the reduced bill represents lower energy use, and the value of the avoided energy is akin to these "energy payments." These entities include, for example, consumers that fully invest in energy-efficiency equipment, third-party suppliers of energy-efficiency services, or both, when such costs and revenues (savings) are shared between the two.

[77] A *Renewable Energy Certificate* represents the environmental attributes of 1 MWh 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 sold or traded separately from the electric energy commodity.

[78] As an example, the results showed whether a particular technology addition (e.g., the wind capacity added in Scenario #6) would produce power in a sufficient number of hours and at clearing prices necessary to generate revenues that could cover overall capital and operating costs—or show a revenue gap that would need to be closed through one or more "other revenue" streams (on the basis of the assumptions used in this analysis).

[79] A consumer's actual price of electricity includes electric energy, capacity, ancillary service, transmission, distribution, and other items, such as payments tied to credits for renewable energy sources, and taxes, which appear on retail electricity bills.

marginal electric energy prices were nonexistent as a result of the generic transmission expansion of the transmission system (see Section 2.1.4).[80]

In New England's spot electric energy markets, load-serving entities pay (and generating units operating in that hour are paid) the clearing price in that hour.[81] When a generator is not on the margin, some of the payments made at the clearing prices may be higher than that generator's variable costs. These "net payments" contribute to covering a generator's other costs (described previously) to own and operate the plant—costs that are not otherwise included in the production costs.

The metric for LSE expenses reflects the total amount that buyers of wholesale electric energy, including utilities and competitive power marketers, would spend to procure this energy in New England's energy markets, if they bought all of their energy through the spot energy market. It is equivalent to the total electric energy revenues that resources, including demand-side resources and imports from neighboring systems, receive for supplying electric energy to the wholesale market. These costs are a proxy for costs to the buyer, recognizing that many LSEs purchase electric energy through bilateral contracts rather than in the spot markets and that they pay other costs that support investment in both supply-side and demand-side technologies.

The net energy market revenues for the energy-efficiency resources of Scenario #2 were estimated the same way as all the other technologies. The ARRs were compared with total annualized revenues, the clearing price ($/MWh) that the LSEs paid was the same, and revenues could increase. However, in reality, energy efficiency reduces costs, it does not increase revenues; all customers pay the total costs for the energy-efficiency resources and share the benefits through lower energy costs.

3.3.2 Reliability Metrics

Because the region currently relies heavily on natural gas to generate electricity, the addition of alternative resources will assist in diversifying the fuel supply. Reliability metrics were developed to assess the region's risk of exposure to disruptions of natural gas, oil, coal, and nuclear sources of energy. The reliability metrics include the amount of electric energy generated by each type of technology (MWh); the amount of generating capacity provided by the different technologies (MW); the units of fossil fuel that must be delivered into the region (quadrillion Btu); and the amount of operable capacity available (or deficient) in the region in the event of a disruption in the availability of fuels (MW), as an indication of the region's exposure to potential fuel-supply disruptions.

3.3.3 Environmental Metrics

For each scenario and sensitivity case, the environmental metrics include the total NO_X, SO_2, and CO_2 emissions and the total pounds of mercury emissions before applying extraction controls. The total amount of regional NO_X emissions for the 10 highest NO_X-emission days was also calculated. Other metrics that were provided, which reflect various risks, are as follows:

- Amount of fossil fuel used by New England resources

[80] Differences in the clearing price of electric energy for various areas of the system, known as *locational marginal prices* (LMPs), could exist if transmission were constrained.

[81] A *spot market* typically involves short-term, often interruptible contracting and immediate delivery of specified volumes of electric energy, as opposed to bilateral trading.

- Extent to which the volatility of the fossil fuel markets (principally gas and oil) affected the regional emissions level

- Extent to which the scenario depended on the investment in and siting of energy delivery systems (for natural gas or electric transmission)

- Amount of water consumed for cooling power production at new generating facilities

- Percent of total systemwide electric energy produced by renewable fuels—some of which were assumed to be zero-emitting power sources (e.g., wind, photovoltaics, hydro), and others of which have emissions associated with them (e.g., biomass, fuel cells powered by natural gas)

Section 4
The Scenarios and Sensitivities

This section provides more details about the core technology reflected in each scenario and the sensitivity analyses that apply to each. It describes the basic technologies, their key features and attributes, and the technological assumptions used in modeling each scenario.

4.1 Scenario #1—The "Queue" Mix

This scenario depicted conditions that might be present beyond the 2020 to 2025 timeframe assuming that more of the same type of resources that are currently responding to market signals in New England were implemented in larger quantities at that future time. In this scenario, all 8,000 MW of capacity was added according to the types and amounts of generating resources reflected in the ISO's Generator Interconnection Queue as of September 30, 2006, unlike the other scenarios that included just 2,600 MW of the queue mix. As shown previously in Figure 2-2 (p. 19), this mix included fast-start, gas-fired "peaking" (CT) units (57%); gas combined-cycle plants (20%); renewable power plants [composed of biomass, landfill gas (LFG), wind, fuel cells, and hydro projects] (11%); and coal-fired IGCC capacity (12%).[82]

Scenario #1 was also analyzed using the base-case and technology-specific assumptions, as described in Section 2, for fuel prices and the assumptions for capital investment costs, as described in Section 3.1. The heat rates, emission rates, and fuel costs for the different technologies in the queue vary widely. As shown in Table 2-2 (p. 19), these systems were assumed to have a relatively high availability, except for wind, a resource with an inherently limited availability and no heat rates. Natural gas technologies, including fuel cells, have the highest conversion efficiencies; LFG, biomass, and coal IGCC technologies have somewhat lower efficiencies but generally lower-cost fuels.

As with Scenarios #3, #4, #5, and #6 (see the following sections), this scenario assumed that an additional $60 million to $1.8 billion was invested in the transmission system to accommodate the addition of the central station generators that use natural gas and coal as fuels, as well as the expansion of wind resources. This scenario also assumed that no new investment would be made in the regional natural gas infrastructure. All the sensitivity analyses, except the specialized cases, were performed on this scenario.

4.2 Scenario #2—Demand-Side Resources

In addition to the core assumption of adding 2,600 MW of capacity from the queue mix that all scenarios add, this scenario incorporated a significant, 5,400 MW investment in demand-side resources. These resources were presumed to be a mix of end-user technologies and included energy-efficiency measures, technologies that shift demand from on-peak to off-peak hours, and measures that send price or direct control signals to customers to curtail their use in certain high peak-demand periods.

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[82] *Fast-start* resources can start up and synchronize to the system in less than 30 minutes. They help with recovery from contingencies and assist in serving peak load.

Scenario #2 was analyzed using the base-case fuel-price and demand-side assumptions discussed in Section 2. The energy-efficiency resources in this scenario reflected annualized ARR costs for generic technologies in the range of $110 to $400/kW-year. These costs were based on capital investment costs ranging from $920 to 3,300/kW. The demand-response resources reflected installed costs for metering and other equipment ranging from $8 to $10/kW.

Demand-side resources were assumed to produce no emissions. Although some types of demand-side technologies generate air emissions, these types of resources were not modeled in this scenario. It was also assumed for this scenario that expanding the electric transmission system beyond regional system planning projects was not needed and that these demand-side reductions reduced the amount of distribution infrastructure needed for the other scenarios. This lowered the total assumed installed distribution system costs in the range of $100 million to $325 million regionwide.

Because energy-efficiency and demand-response resources were modeled as if they offered "energy" supply at no cost to the system (rather than being modeled as a reduction to the load curve), the outcome of the analysis was that the party that was assumed to invest in these measures was paid the calculated net energy revenues. These revenues are equivalent to the dollar savings gained as a result of consuming less energy by "using" these resources. Scenario #2 was assumed to dispatch 18 million MWh of "energy" at no cost.

Scenario #2 was examined with the robust set of sensitivity cases described previously in Table 3-1 (p. 34). The Double EE sensitivity case was assumed to dispatch 36 million MWh of no-cost "energy," which is comparable to the nuclear and coal IGCC scenarios. For the retirement case, a total of 2,600 MW of supply-side expansion resources from the queue and an additional 8,900 MW of demand-side resources were added, while 3,500 MW of older capacity was removed.

4.3 Scenario #3—New Nuclear Plant Capacity

This scenario applied the common assumptions of adding 5,400 MW of nuclear capacity, located at or near existing nuclear stations, and spending $60 million to $1.8 billion in new transmission investment to interconnect the nuclear facilities to the grid.[83] This scenario assumed that no new investment was made in regional natural gas delivery infrastructure, but like all other core scenarios, Scenario #3 assumed that 2,600 MW of capacity was added from the queue mix.

The nuclear expansion case also assumed the following:

- A base-case fuel price of $17/MWh (which includes maintenance and waste disposal)
- 10,000 Btu/kWh heat rate (midrange efficiency)
- 90% availability factor
- Capital costs ranging from $3,000/kW to $5,000/kW
- Zero emissions of air pollutants from the plant

[83] Additional information about these cost assumptions is available online.

All non-production-related costs were captured in the annual revenue requirements range of 15% to 25% of capital costs. Scenario #3 was analyzed using the full set of sensitivity analyses shown in Table 3-1 (p. 34).

Because this scenario had low production costs and zero emissions, the IREMM simulation results for this scenario might also represent the combined effects of the energy-efficiency technologies that could always be present in a constant and continuous amount (e.g., a refrigerator but not an air conditioner) similar to a baseload generator.

4.4 Scenario #4—New Coal-Fired Power Plants Using Integrated Gasification Combined-Cycle Technology

This scenario added coal IGCC generating capacity. This technology was considered in two ways: one, without investment or operating costs associated with capturing the CO_2 as a separate, add-on process after the coal-gasification process; and another, involving investment to capture and then transport and sequester the CO_2. The IGCC capital costs and efficiency penalties associated with the carbon capture are shown in Table 2-2 (p. 24).

Capital costs for coal IGCC without CO_2 capture at the plant were assumed to fall in the range of $2,500/kW to $3,500/kW; by contrast, the capital costs were $400/kW higher for adding a plant module for carbon capture. An additional cost of $25/ton was associated with carbon transportation and storage.

This scenario assumed that no regional natural gas delivery infrastructure was added, but that $61 million to $1.8 billion was invested for electric transmission expansion. In addition to the carbon sequestration sensitivity case, all the general sensitivity cases were run for the scenario, as shown in Table 3-1 (p. 34).

4.5 Scenario #5—New Gas-Fired Combined-Cycle Power Plants

This scenario added 5,400 MW of the natural-gas-fired CC technology that dominated the generating capacity additions during the 1995 to 2005 period in New England (and elsewhere in the United States). This scenario also added 2,600 MW of the capacity from the queue mix, which also includes some NGCC capacity.

This scenario assumed that the capital costs for combined-cycle plants ($800/kW to $1,000/kW) and their heat rates (6,500 Btu/KWh) were relatively low compared with other fossil fuel units. Similarly, the air pollution emissions rates for these plants were relatively low. Gas prices, by contrast, were assumed to be relatively high compared with prices for other fuels, even in the base-case fuel-price forecast. The operating costs of these plants are directly tied to regional natural gas prices.

This scenario assumed that that the natural gas delivery infrastructure expanded significantly for an incremental cost ranging from $150 million to $1.5 billion. This reflects a combination of projects involving, for example, gas pipeline expansions and additional liquefied natural gas import terminals and regasification facilities. For the retirement sensitivity case, the amount of conceptual investment in incremental natural gas infrastructure increased to a range of $400 million to $3 billion. This scenario assumed that the expansion of electric power transmission cost $61 million to $288 million.

Scenario #5 was analyzed with all but the specialized sensitivity cases.

4.6 Scenario #6—New Renewable Plants

This scenario includes a combination of various renewable resources projects as follows:

- Offshore wind
- Inland onshore wind
- Biomass
- Fuel cells
- Landfill gas
- Combined heat and power systems
- Solar photovoltaic technologies
- Hydroelectricity

The total capacity included in this scenario was designed to be equivalent to the 5,400 MW of capacity included in the other scenarios, with one-eighth of this amount of equivalent capacity coming from each of these renewable technology types. This scenario also added 2,600 MW of capacity from the queue mix, some of which also included other renewable resources (i.e., wind, hydro, fuel cells, biomass, and LFG capacity) (see Figure 2-2, p. 19).

This scenario added resources with capital costs ranging widely from $1,000/kW to $6,000/kW (on a nameplate capacity basis), as shown on Table 2-2 (p. 24), for LFG, biomass, fuel cell, wind, and combined heat and power (CHP) capacity. Other characteristics of the resources in this scenario are that wind, solar, and hydro resources have no air emissions, and the other technologies have low emissions (see Table 2-3, p. 28). Some resources (e.g., onshore and offshore wind and solar PV systems) have no fuel costs or air emissions; others have air emissions and relatively poor heat rates. Two technologies, CHP and fuel cells, generate exhaust heat, which can serve an on-site energy demand for process heat, hot water, steam, or other uses.

This scenario assumed that the regional natural gas distribution systems were not expanded to provide incremental gas for the fuel cells and the CHP systems. However, it was assumed that the rates that local distribution companies (LDCs) charged for local gas expansion provided sufficient compensation for transport services, with an associated delivery and distribution charge in the range of $0.195/therm to $0.445/therm.[84,85] Additionally, the onshore and offshore wind resources were assumed to need additional electric transmission facilities and cost in the range of $581 million to $3.9 billion. Scenario #6 was analyzed with the full set of general sensitivity cases. For the retirement case, 8,900 MW of the new resources were assumed to be renewable resources.

[84] One therm of natural gas is equivalent to 100,000 Btu, which is roughly equivalent to the heat content of 100 cubic feet of natural gas.

[85] In addition to these LDC distribution charges, the gas shippers (for fuel cells and CHP systems) would also need to pay the commodity cost of gas, pipeline transportation charges, fees for imbalance resolution, and an allowance for lost and unaccounted for gas.

4.7 Scenario #7—Increased Imports of Hydroelectricity and Other Low-Emission Resources

This final scenario involves the construction and operation of a new major transmission system into New England to provide the capability to import 30 million MWh of power on a firm basis from neighboring regions with a profile of up to 5,400 MW during high-load periods. This scenario, like the others, included the addition of 2,600 MW of capacity from the queue mix. This scenario also assumed that the power imported into the region was from a power source, such as hydroelectric, wind, or nuclear, that does not contribute air emissions. Because these resources all have characteristics typical of hydro resources, the model dispatched them to serve peak-demand periods and were based on other underlying assumptions for the costs associated with the need for transmission expansion.

This scenario estimated conceptual transmission costs to import power from Canada, New York, or both. As with other scenarios, these estimates were based on an analysis that examined a range of generic transmission costs. The conceptual transmission cost estimates were developed to the New England–Quebec border and the New England–New Brunswick border to the north and the New England–New York border to the west. These conceptual capital costs range from $3.1 to $8.9 billion, for the New England–Canadian routes, and $1.0 to $2.4 billion to the New York border. Actual transmission projects would be developed as part of the regional plan and would be fully integrated into the New England network.

Capital investment costs on the other side of the border of New England could vary widely (see Section 3.3.1), and the commercial terms of any agreement to import power from a neighboring region would likely differ from the assumptions made in Scenario Analysis. The cost estimates for Scenario #7 are likely understated compared with those of other scenarios; most notably, it is unlikely that power production and transmission facilities needed on the Canadian side of the border would not have associated costs.

Scenario #7 analyzed the full set of general sensitivity cases. Under the sensitivity case that assumed that 3,500 MW of demand-side resources replaced import capacity, the import capacity decreased from 5,400 MW to 1,900 MW, the energy transferred to New England decreased from 30 million MWh to 11 million MWh, and the amount of generic costs for transmission expansion was halved. The retirement sensitivity case for this scenario retired 3,500 MW of existing generating units (as of 2007) and replaced them with an equivalent amount of additional imported energy and capacity (20 million MWh and 3,500 MW, respectively). This case also assumed that the transmission facilities necessary to import the additional 3,500 MW of power needed additional expansion. The low-import sensitivity case was assumed to involve importing only 23 million MWh, rather than 30 million MWh, via the new tie line but with the same cost for the transmission line and the same 5,400 MW of capacity.

Section 5
Results and Observations

This section summarizes the key production, economic, reliability, and environmental results for each scenario and compares the results for the common set of assumptions with the results for the sensitivity cases. Detailed and summary tables and charts showing additional results and comparisons are available on the ISO's Web site.[86]

These results are intended to provide information for future discussions about different public policies that can be pursued if one particular type of technology or several hold particular interest or value for the region. The ISO encourages interested parties to compare the results for the different scenarios and reach their own conclusions about the various technology outcomes.

5.1 Economic Results

Several key economic metrics were analyzed for the different scenarios and sensitivity cases, including production costs, average clearing prices, load-serving entity costs, and comparisons of each technology's net annual wholesale energy market revenues minus its annual revenue requirement. The results for the scenarios differed considerably across these economic metrics.

Table 5-1 summarizes the annual production and wholesale electric energy market costs and average clearing prices under the common set of assumptions and the Double EE case. It also compares these costs with the costs for Scenario #1 (the queue). These results are discussed in subsections that follow.

[86] The material available on the Web site allows the user to adjust the "post-processing" assumptions about the capital costs of the generating resources or demand-side measures, the needs and costs of the transmission and distribution systems, and such other things as the costs of carbon sequestration. The user, however, cannot rerun the production simulation model with different assumptions.

Table 5-1
Annual Production and Wholesale Electric Energy Market Costs and Average Clearing Prices for the Scenarios and Double Energy-Efficiency Sensitivity Case Compared with the Queue Case under the Common Assumptions[(a)]

Scenario	Electric Energy Produced by Scenario Resource (TWh)[(b)]	Prod. Cost ($ mil)	Change from Queue ($ mil)[(c)]	% Change from Queue[(b, c)]	Avg. Clearing Price ($/MWh)	Change from Queue ($/MWh)[(c)]	% Change from Queue[(c)]	Annual Wholesale Electric Energy Market Cost to LSEs ($ mil)	Change from Queue ($ mil)[(c)]	% Change from Queue[(c)]
1. Queue	24	6,833	-		69	-		11,997	-	
2. EE/DR[(d)]	18	6,298	–535	–7.8	70	1	1.4	12,235[(d)]	238	2.0
3. Nuclear	43	5,502	–1,331	–19.5	61	–8	–11.6	10,566	–1,431	–11.9
4. Coal IGCC	38	6,525	–308	–4.5	63	–6	–8.7	10,895	–1,102	–9.2
5. NGCC	40	6,825	–8	–0.1	62	–7	–10.1	10,796	–1,201	–10.0
6. Renewables[(e)]	47	5,569	–1,264	–18.5	60	–9	–13.0	10,344	–1,653	–13.8
7. Imports[(f)]	30	5,522	–1,311	–19.2	64	–5	–7.2	11,085	–912	–7.6
Double EE[(d)]	**36**	**5,148**	**–1,685**	**–24.7**	**62**	**–7**	**–10.1**	**10,811**	**–1,186**	**–9.9**

(a) Capital costs are not included per se.

(b) Of the 8,000 MW of capacity added in each scenario, 2,600 MW reflected the “queue” mix. The remaining 5,400 MW was composed of each scenario’s core technology or mix of technologies. Because of the varying assumptions about each technology’s capacity value (see Section 2.2.1), the 5,400 MW of each scenario’s core technology produced different amounts of electric energy. See table note (d) for more information on how the energy “produced” by energy-efficiency and demand-response resources was estimated.

(c) “ –” = cost savings; “+“ = more costly.

(d) Because energy-efficiency and demand-response resources were modeled as if they offered “energy” supply at no cost to the system (rather than being modeled as a reduction to the load curve), the outcome of the model was that the party that invested in these measures was paid the calculated net energy revenues. These revenues are equivalent to the dollar savings gained as a result of the reduced energy consumed by "using” these resources. Scenario #2 (EE/DR) was assumed to “dispatch” 18 million MWh of no-cost energy, and the Double EE case was assumed to “dispatch” 36 million MWh of no-cost energy. While this approach did not affect production costs or average clearing prices, it did affect total LSE costs, since it overestimated the amount of electric energy that needed to be purchased. Because being more energy efficient would reduce the total amount of energy that LSEs would need to purchase, their total expense would go down (even though the price per unit of electricity purchased would be unaffected). These savings were not subtracted from the results for the energy-efficiency scenarios posted in the column labeled “Annual Wholesale Electric Energy Market Cost to LSEs.”

(e) “Renewables” is a composite of onshore and offshore wind, solar photovoltaics, biomass, landfill gas, fuel cells, hydro, and combined heat and power—each weighted at one-eighth of the total capacity.

(f) The table includes costs for New England resources only; it was assumed that the imports in the production simulations would accept the clearing price in New England.

5.1.1 Production Costs

As shown in Table 5-1, under the common set of assumptions, the cost for the seven scenarios to produce electric energy ranged from a low of approximately $5.5 billion (Scenarios #3, nuclear; #6, renewables; and #7, imports) to a high of almost $7 billion for Scenario #1 (the queue) and Scenario #5 (NGCC). In these analyses, production costs largely reflected fuel-related costs, including emissions allowances, to run the entire New England-wide bulk electric power system. Across the scenarios and sensitivity cases, the annual systemwide production costs ranged from a low of less than $4 billion (Scenario #7, imports) in the low-gas-price sensitivity case to a high of approximately $10.5 billion (Scenario #5, NGCC) in the high-gas-price case.[87]

The lower systemwide production costs for all scenarios compared with Scenario #1 (the queue) indicates an improvement in overall system efficiency. The systemwide production costs for Scenario #2 (demand-side resources), for which energy efficiency provided 18 million MWh of energy at no production cost, were $6.3 billion. While Scenario #2 had high production costs relative to some of the other scenarios, because half of the capacity was from peak-shaving demand response, the sensitivity case that assumed energy efficiency was doubled (with no demand response) had decreased production costs. The production costs for the Double EE case were the lowest ($5.1 billion) among the seven scenarios under the common set of assumptions.

The sensitivity cases that retired older generating units produced electric energy at lower costs relative to the simulations under the common set of assumptions. The sensitivity cases with high carbon-allowance prices tended to have higher production costs compared with the scenarios under the common assumptions.

5.1.2 Average Clearing Prices

Figure 5-1 shows the patterns of average clearing prices across all the scenarios and sensitivity cases. Combined with the results shown in Table 5-1, these results show the effect of either changing the resource mix or changing input costs on the average cost of electric energy.

The average clearing prices for the cases under the common set of assumptions ranged from $60 to $70 per MWh, as shown in Table 5-1 and Figure 5-1. This range is relatively small compared with the differences in the patterns across the sensitivity cases. For example, the average clearing prices for the sensitivity cases with low and high gas prices varied by approximately $60/MWh across all technologies. The greatest change in wholesale electric energy costs resulted from changes in the fuel prices, which suggests that the key driver of average clearing prices was the gas-price assumption. This is because gas-fired power plants were often the marginal generators and frequently set clearing prices in each scenario. For example, gas units were on the margin for approximately 90% of the hours in all common-assumption scenarios, as shown in Figure 5-2.[88] It appears that the region's average clearing prices were less sensitive to gas prices in the scenarios and cases for which more aggressive levels of demand-side resources replaced, in part, the core technology.

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[87] Detailed and summary tables and charts showing additional results and comparisons are available on the ISO's Web site.

[88] The strong sensitivity of production costs to natural gas prices would exist whether the region used the marginal pricing approach currently in use or a "pay-as-bid" average pricing approach. The current marginal pricing system has been shown to be more economically efficient. For additional information, see the ISO's ***Electricity Costs White Paper*** (Holyoke, MA: ISO New England, 2006).

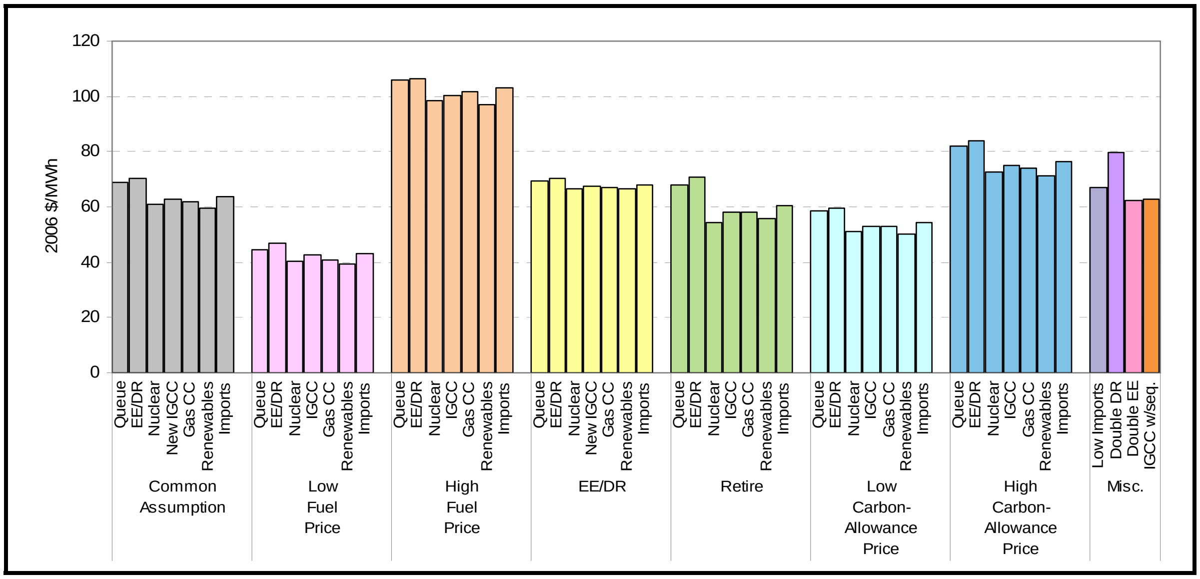

Figure 5-1: Average clearing price for wholesale electric energy, grouped by sensitivity case, $/MWh.

Note: For this analysis, the average clearing price was calculated as the sum of the hourly clearing prices for the year divided by the 8,760 hours of the year. Using this framework, modeling demand-side resources as either supply-side resources or as nonparticipants in the market would not change the average clearing price results.

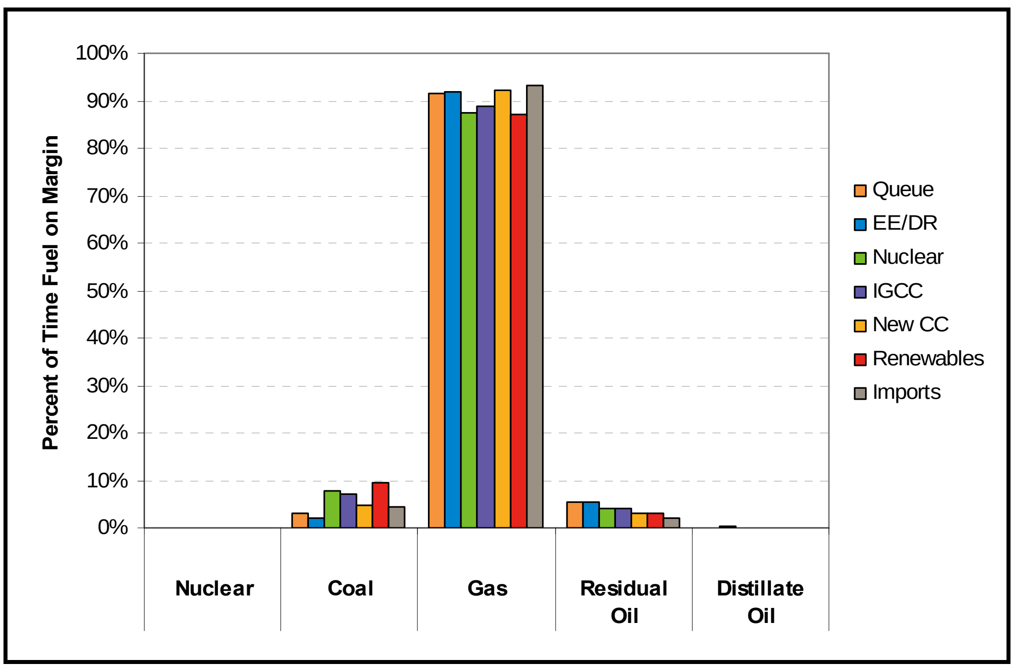

Figure 5-2: Percent of time fuel is on the margin.

It seems that the addition of regional natural gas supply and delivery system infrastructure and reductions in gas-sector demands could mitigate prices during periods of high demand. Several demand-side technologies could provide the dual benefits of reducing the demand for both natural gas and electrical energy (e.g., efficient gas-fired heating systems, improved home insulation, HVAC environmental controls, and other measures), which could reduce the price of both natural gas and electricity.

5.1.3 Annual Wholesale Electric Energy Market Costs

Figure 5-3 shows the results for annual wholesale electric energy expenses for buying power in the wholesale spot markets (in 2006 dollars) across all simulations, grouped by sensitivity case. Across the scenarios and on a New England-wide basis, load-serving entity expenses for electric energy ranged from about $10.5 billion to about $12 billion under the common set of assumptions. Scenarios #3 and #6 (nuclear and renewables) and Scenario #2 (with double energy efficiency) had LSE expenses at the lower end of the range. At the higher end of the range were Scenario #1 (the queue) and Scenario #2 (demand-side resources), especially the sensitivity case with all demand response.

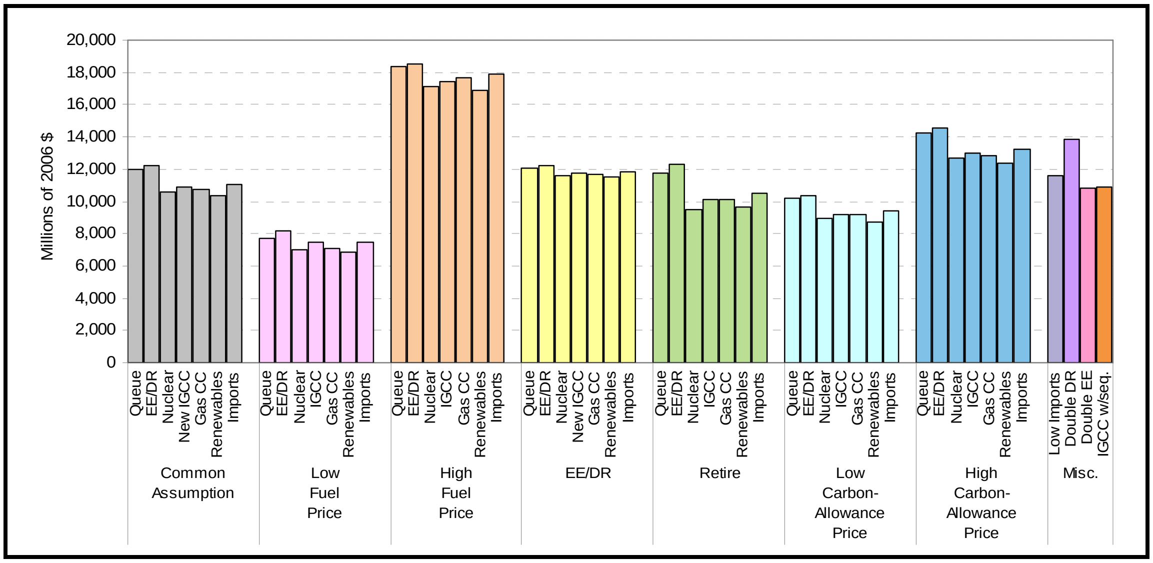

Figure 5-3: Load-serving entity annual expense for wholesale electric energy, grouped by sensitivity case, millions of 2006 dollars.

Note: The figure does not include other market payments, such as capacity payments, or transmission costs, which would likely vary by scenario.

Load-serving entity costs were dramatically higher in the cases in which natural gas prices were assumed to be greater, with expenses totaling from approximately $16+ to $18+ billion across the scenarios. Conversely, payments were lower in the low-fuel-price cases, ranging from approximately $6.5 billion to $8.0+ billion. Across the various sensitivity simulations, Scenarios #3 and #6 (nuclear and renewables) tended to have the lowest costs for electric energy, and Scenarios #1 and #2 (the queue and demand-response cases) tended to have costs at the higher end.

As shown previously in Table 5-1 (p. 48), annual wholesale electric energy market costs correlated directly with the average clearing price for the scenarios under the common set of assumptions. In general, as shown in Figure 5-3, buyers of the scenarios' wholesale electric energy (the load-serving entities) faced the lowest expenses when gas prices were low and the highest expenses when gas prices were high, regardless of the scenario examined. Like average clearing prices, these annual wholesale energy market expenses were largely shaped by the assumptions about the future price of natural gas; high gas prices tended to support more of the capital investment needed to pay for non-gas-fired technologies (as well as gas-fired technologies).

Although demand-side resources were modeled to satisfy the same load levels assumed for the other scenarios and sensitivity cases, they were not "dispatched" in the same way as power plants, and LSEs were assumed to have purchased as much electric energy as in the cases without demand-side resources. While this did not affect the production cost or clearing price estimates in any hour (since the demand-resources were effectively bid in at zero cost), it did increase the total amount of electric energy LSEs purchased over the course of the analysis year for the scenarios and cases with demand-side resources. That is, for the scenarios and sensitivity cases with demand-side resources, the total amount of electric energy LSEs purchased was the same as and not less than the amount purchased for the supply-side cases. Therefore, to show results that are more consistent with much of the current rate structure for demand-side resources, the scenarios and sensitivity cases that included demand-side resources could be adjusted to reflect the lower amount of electric energy that would need to be purchased compared with the cases that did not deploy incremental energy efficiency, demand response, or both.[89, 90]

5.1.4 Comparison of Annual Revenue Requirements and Revenues

Comparisons of the annual revenue requirements and net revenues are discussed below; a discussion of assumed revenues from the wholesale markets is included.

5.1.4.1 Annual Net Energy Revenues Compared with Revenue Requirements

Figure 5-4 compares net annual revenues in the regional energy markets with annual revenue requirements for the various types of individual resources, under the assumptions used in this analysis. It also indicates (under these assumptions) the amount of financial support a particular technology might need through means besides the energy markets to be attractive to investors. This particular snapshot of net revenues compared with investment carrying costs does not fully indicate the extent to which a technology might qualify for financial incentives to investors (such as tax incentives like production tax credits or accelerated depreciation for certain renewable technologies). Further, these figures do not include the capital costs of any transmission investment that might be needed as part of adding a particular type of resource.

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[89] For example, according to the Northeast Energy Efficiency Partnership, in the case of state-funded energy efficiency programs, the cost of efficiency is less than $35/MWh. In Vermont, the lifetime cost is 3.6 cents/kWh (for 2005), including participant costs. In Maine, 2.9 cents per lifetime kWh has been saved, including costs for that state's Efficiency Maine program and participant costs. In Massachusetts, 3.2 cents/kWh have been saved based on 2005 performance and including costs for program administration and participants. In Connecticut, 2.0 cents/kWh have been saved.

[90] Stakeholders can use the spreadsheet tool to adjust the data for the cases that involve demand-side resources.

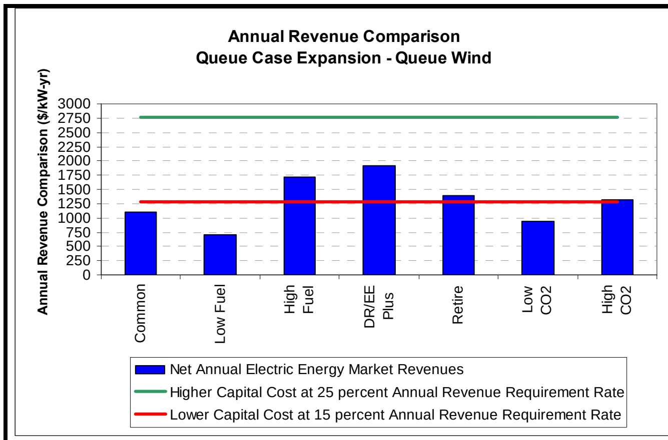

Figure 5-4a-Queue: wind (see figure note 2).

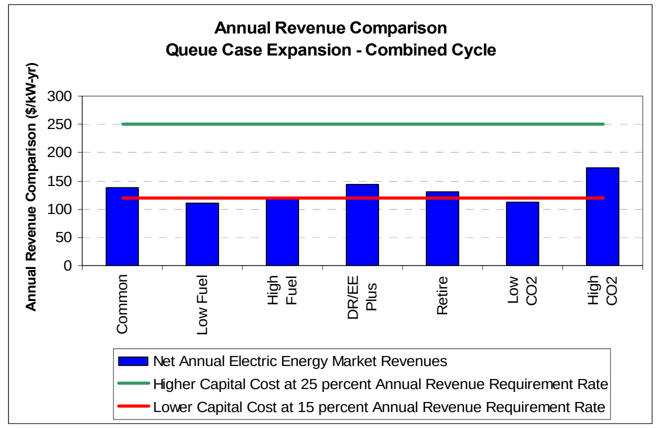

Figure 5-4b-Queue: combined cycle.

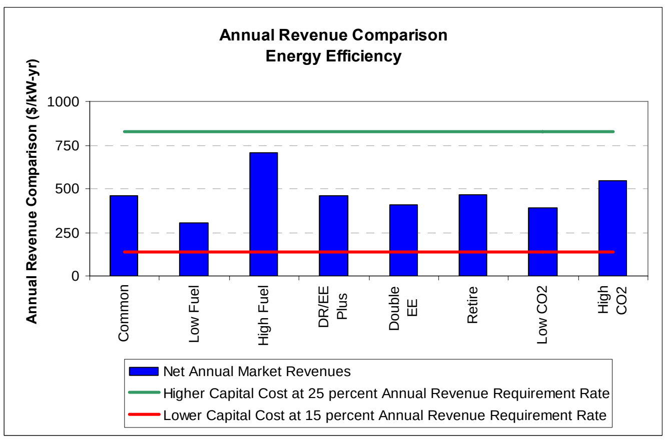

Figure 5-4c: Energy-efficiency resource in Scenario #2 (see figure note 3).

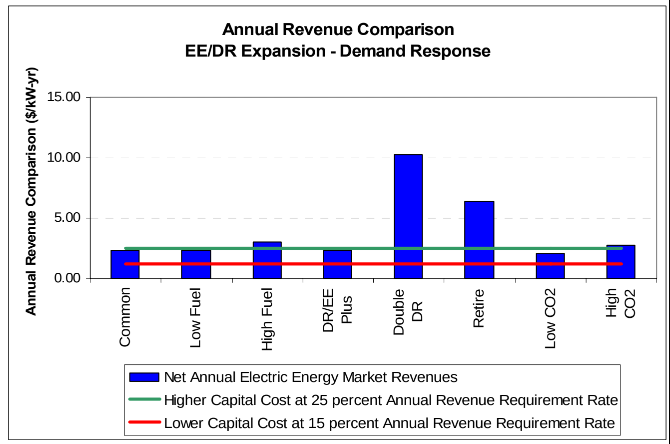

Figure 5-4d: Demand-response resource in Scenario #2 (see figure note 4).

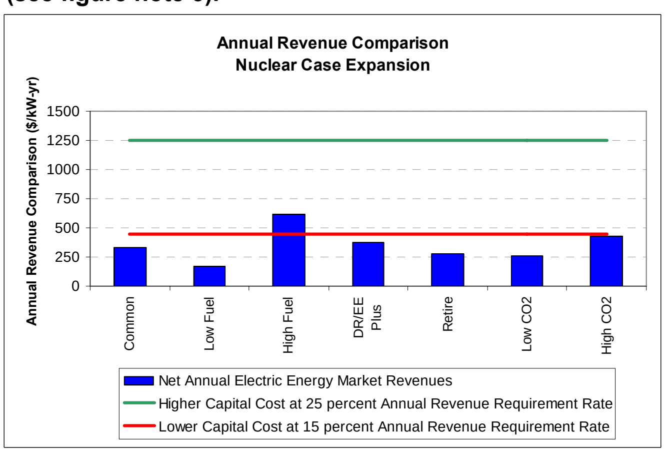

Figure 5-4e: New nuclear.

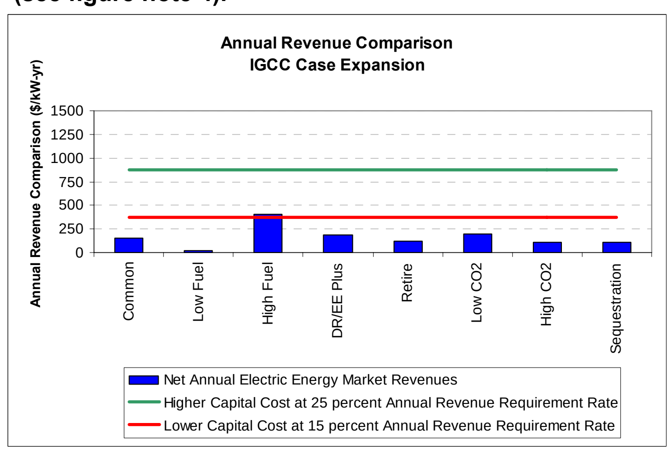

Figure 5-4f: New coal IGCC without sequestration.

Figure 5-4 (a–f): Net annual revenues compared with annual revenue requirements for selected scenarios.

Notes: 1) Due to space limitations, only selected technologies are included in this table. Other results are available on the ISO's data-extraction spreadsheets Web site. The *y* axes, which denote cost per kW-year, vary by chart. 2) For the queue scenario shown in Figure 5-4a, the indicated revenue requirement for the renewable wind expansion does not reflect the tax benefits (including accelerated depreciation and production tax credits) that are available under current tax policies and that would significantly lower the applicable after-tax revenue requirements for these technologies. 3) In Figure 5-4c, the red and green ARR indicators reflect the 15% and 25% assumptions to be able to compare the data for all scenarios. However, a more typical ARR for energy efficiency of 12% was assumed, as summarized in Section 4.2, to develop an equivalent capital investment range for EE. 4) Because some demand-response approaches involve more energy reduction than modeled, demand-response measures may well provide greater energy megawatt-hour savings or revenues than determined by these analyses or shown in this figure.

Figure 5-4c serves as an example to explain the information portrayed in each of the subfigures of Figure 5-4. This chart shows information about the energy efficiency added in Scenario #2 (demand-side resources). Each vertical (blue) bar in this chart shows the support that energy-efficiency savings received in the market and, for example, that efficiency resources produced approximately $461/kW-year of net annual electric energy market revenues under the common set of assumptions. In the sensitivity with high fuel prices, these energy revenues were approximately $704/kW-year.

Figure 5-4 also shows two horizontal lines. The lower (red) line reflects the annual costs associated with the low capital cost estimates and the so-called revenue requirement for the low end of the cost range using a low estimate of carrying costs (15% per year) for energy-efficiency technologies. The higher (green) line reflects the higher end of the range of investment costs and a high estimate of carrying costs in a given year, at 25%. A comparison of the revenue figures with the range of annual carrying costs of energy-efficiency investment for Figure 5-4c indicates that energy-efficiency resources would be economic at low- to mid-range investment cost estimates on the basis of the revenues (or savings) gained from just the electric energy market. Other reasonable revenue streams, such as payments for the capacity value of efficiency for avoiding the use of energy during periods of peak electricity use, were not accounted for, however.

Each of the charts in Figure 5-4 provides similar types of information for the technologies. The horizontal lines show high and low estimates of annual revenue requirements, and the vertical bars reflect the net revenues in energy markets alone, absent any changes in policy or other revenue streams.

5.1.4.2 Annual Net Energy plus Capacity Revenues Compared with Revenue Requirements

Table 5-2 summarizes the cost and revenue information for all the technology cases and includes some additional data on market revenues. Figure 5-5 shows this information graphically. On the figure, for each of the seven core scenario technologies, cost and revenue information appear in two pairs of vertical bars. For example, for Scenario #2 (demand side, including both energy efficiency and demand response combined), the two bars on the left reflect the range for low to high annual revenue requirements, and the two bars on the right indicate the range for low to high annual revenues. The two ARR bars include not only the costs for the resource but also the cost for incremental transmission and distribution for that scenario. Of the two revenue bars, the one on the left includes revenues from the electric energy market along with Forward Capacity Market payments assumed to be at a level of $54/kW-year. The right-most revenue bar for each scenario has the same electric energy market revenues and assumed that FCM revenues were at a $126/kW-year level. For each technology, the two left-side cost-related bars can be compared with the two right-side revenue-related bars.

Table 5-2
Total Annual Revenue Requirements and Annual Net Revenues for the Scenarios under the Common Set of Assumptions, Millions of 2006 $

Scenario under Common Assumptions	Low/High	Annual Revenue Requirements: Scen. Costs	Transm. & Distrib.	Gas Pipeline	Total Req.	Annual Wholesale Market Revenues: Net Energy Market Revenues	FCM Rev.	Total Rev.	Annual Revenues Less Requirements: Less Favorable[a]	More Favorable[b]
1. Queue	L	1,313	11	0	1,324	846	300	1,146	–2,151	221
	H	2,898	399	0	3,297	846	699	1,545		
2. EE/DR	L	421	–72	0	349	1,251	292	1,543	–748	1,583
	H	2,309	–18	0	2,291	1,251	680	1,932		
3. Nuclear	L	2,430	11	0	2,441	1,793	292	2,084	–5,065	32
	H	6,750	399	0	7,149	1,793	680	2,473		
4. IGCC	L	2,025	11	0	2,036	835	292	1,126	–3,998	–521
	H	4,725	399	0	5,124	835	680	1,515		
5. Gas CC	L	648	11	27	686	492	292	784	–1,295	487
	H	1,350	399	330	2,079	492	680	1,173		
6. Renewables	L	3,980	105	0	4,085	1,667	292	1,959	–7,833	–1,737
	H	8,926	866	0	9,792	1,667	680	2,348		
7. Imports	L	0	683	0	683	1,908	292	2,200	235	1,905

(a) Less favorable comparison = (lower net annual revenues – higher total annual revenue requirements).

(b) More favorable comparison = (higher net annual revenues – lower total annual revenue requirements).

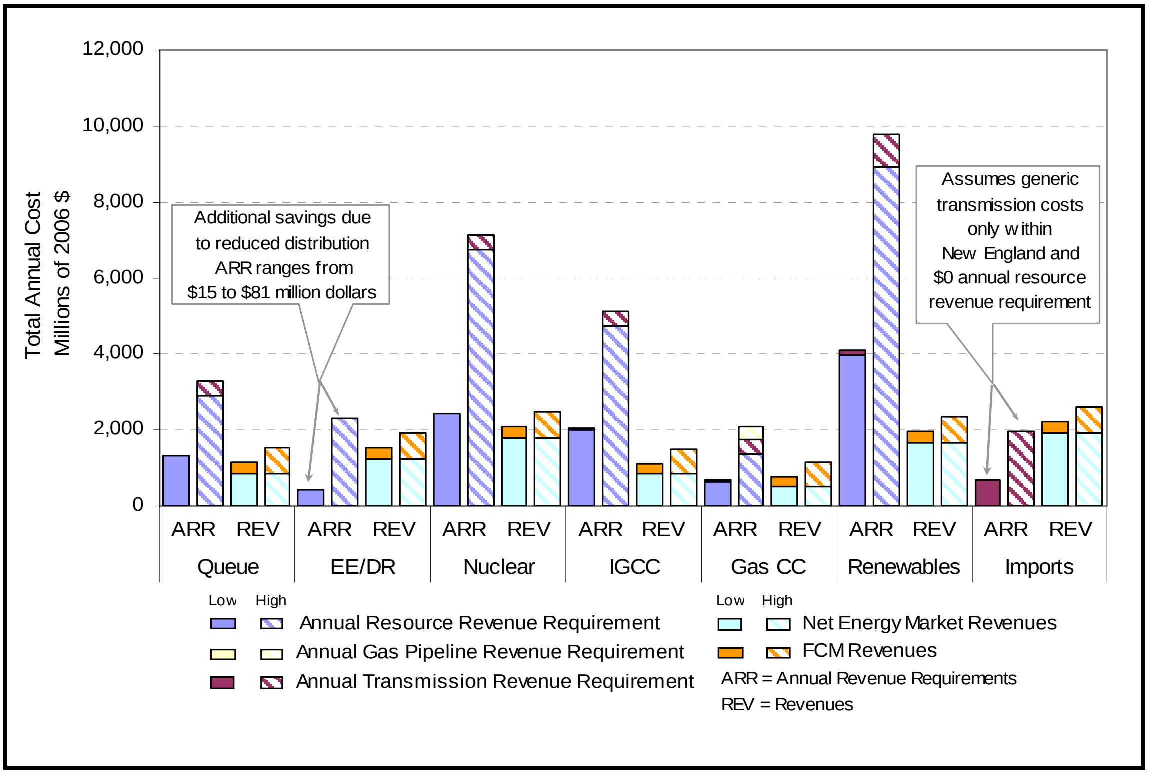

Figure 5-5: High and low annual revenue requirements compared with FCM plus net energy market revenues for the scenario technologies under the common set of assumptions.

Note: The capacity values used in these calculations for most resources were based on the full nameplate capacities of the capacity additions, typically 5,400 MW; the CV values used for additional PV and wind resources were based on 675 MW.

For each scenario, comparing the revenue bars (at either the high or low end of the range) with the ARR bars (at either the high or low end of the range) indicates the extent to which New England's energy and capacity markets might expect to support a particular type of technology. These are rough indications, however, and actual costs and revenues are tied to a variety of actual prices in the energy and capacity markets, site-specific issues, tax issues, and other factors that would cause the assumptions for a particular technology to vary from those used in this analysis. In this analysis, the "gaps" between the annual revenue requirements and the estimated market-based revenue streams reflect an economic hurdle that a particular technology might face. To the extent that policymakers prefer to support a particular technology for reasons unrelated to these costs (e.g., for a reliability or environmental issue), these gaps may point to areas of interest for further policy analysis.

To continue with Scenario #2 (demand side) as an example, the demand-side technologies appeared to have revenues (the proxy for energy savings) sufficient to cover investment costs (i.e., annual revenue requirements) at the low to mid range of the cost estimates. By contrast, the mid to high cost estimates for nuclear and some renewables indicate that, under the assumptions used, the amount of revenue earned from just the energy markets might be insufficient to support these technologies, although this snapshot does not reflect the significant tax advantages investors in advanced nuclear and renewables technologies might accrue.

The various technologies showed different abilities to recover their capital and other fuel costs from the sale of electric energy that depends largely on the fuel-price assumptions (see Section 3.3.1.1). For example, many technologies (including energy efficiency, small hydro, biomass, coal IGCC, wind, nuclear, landfill gas, and imports) came close to meeting the annual revenue requirements at the low end of their capital cost ranges only under the high-fuel-price scenarios. The results for these simulations show that the gap between net electric energy market revenues and annual revenue requirements was present for all technologies except energy efficiency, demand response, and imports from neighboring systems, but the latter assumed no resource capacity costs and no transmission costs outside New England. The addition of these currently unknown costs could significantly change the economic benefits shown in Figure 5-5. Energy efficiency nearly covered its annual revenue requirements based on avoiding energy consumption at wholesale energy market rates.

After energy efficiency and demand response, which appear to have covered their ARRs through electric energy market "revenues," NGCC and imports came closest to covering their revenue requirements, under the assumption that these resources had low emissions and no direct revenue support for capacity. Biomass, small hydro, and nuclear technologies had wider margins between annual revenue requirements and electric energy revenues. These resources, with their relatively low operating and production costs, received a significant capital contribution from the electric energy markets—although not sufficient to reach the midrange of the annual revenue requirements.

These other technologies tended to have a significant gap between net revenues and capital costs, even at the low end of the capital cost range. Assuming the fuel and allowance prices under the common set of assumptions, the gap between net revenues and capital costs was relatively large for PV systems, coal IGCC (with or without carbon sequestration), and offshore and onshore wind.

Notably, two technologies (CHP and fuel cells), which are part of Scenario #6 (renewables), had negative electric energy market revenues in this analysis. These results stem from a modeling representation that did not include the collateral energy benefits of using the steam loads (waste heat) and resultant fuel efficiency that fuel cells and CHP provide to the facilities where they are installed. The model also did not capture other benefits, such as not needing diesel backup electric systems (and potential corresponding air permits). However, the simulations for these technologies reflected the operation of these facilities at maximum output on a nondispatchable basis (which typically is at a customers' site behind the meter). In this analysis, fuel cells ran on natural gas as baseload, and their fuel costs frequently exceeded their energy market revenues. In general, this technology is expensive, and many applications may need financial subsidies. Without considering the use of the waste heat that these technologies provide, no real observations or comparisons can be made about these economic results of the Scenario Analysis.

5.1.4.3 Limitations of the Economic Analysis

While these economic metrics provide basic information for comparing the costs of the various technologies, they do not provide complete information for comparing the scenarios' costs. For example, the analysis provided information for a single year only and did not consider important site-specific savings and costs associated with locating a particular technology in one area or another. Additionally, the analysis did not capture existing tax incentives (e.g., investments in renewable, nuclear, and coal IGCC technologies) or reflect those costs for investing in energy efficiency that are funded by consumers, who benefit by having lower overall energy use.

Additionally, the Scenario Analysis did not address many of the overall charges in a customer's bill, which include the full costs to deliver power. Consumer bills comprise a number of fixed charges plus utility rates that cover generation, transmission, and distribution, the latter charges tending to be affected by consumer levels of consumption. Consumer rates also cover the effects of inflation, the year-to-year variation in underlying prices of fuels used to generate electricity, weather-related impacts on the volumes of electricity sold, and so forth. Therefore, the partial economic results presented suggest—rather than fully explain—the cost differences among the technology options.

5.2 Reliability Results

This section highlights the results related to the energy mix, fuel-use patterns, and operable capacity analysis for each of the scenarios.

5.2.1 Energy Mix and Fuel-Use Patterns

The following discussion focuses on the production of electricity and the amount of fuel the various types of resources used under the modeling assumptions to meet the overall systemwide energy needs of approximately 174 million MWh (174 TWh).

5.2.1.1 Natural Gas Use and Power Production

The amount of natural gas each sensitivity case used to produce electric power differed substantially as a result of various factors. Under the common set of assumptions for the seven scenarios, the electric energy that NGCC power plants produced ranged from a low of about 55 million MWh (in Scenario #3, nuclear) to a high of about 97 million MWh (in Scenario #5, NGCC). Scenario #1 (the queue) and Scenario #2 (demand-side resources) used relatively large amounts of natural gas to produce approximately 83 million MWh and 76 million MWh of power, respectively. In Scenario #2, demand response provided half of the capacity expansion but no significant amount of electric energy. Because these resources were assumed to primarily reduce peak demand, existing gas-fired generation operated more often in this scenario than in many others. Compared with the scenarios under the common set of assumptions, the technologies in the sensitivity cases produced varying amounts of gas-fired electric generation, as follows:

- When natural gas prices were assumed to be high, gas use tended to drop by roughly one-third, relative to the gas use in each initial scenario. When natural gas prices were assumed to be low, gas use increased by roughly 10 to 20%.

- In the sensitivity cases in which greater demand-side technology replaced supply-side technology, the use of gas increased relative to the original scenarios. This is in large part because, like under the common set of assumptions, demand response was not assumed to introduce much energy-producing capacity into the overall capacity expansion plan. Therefore, electricity generation at fossil-based production facilities rose, even when energy efficiency lowered overall energy use.

- When older power plants were assumed to retire, the use of natural gas was similar to the level in the scenarios under the common set of assumptions, except in the case in which more gas-fired plants were assumed to replace retired capacity.

- The use of natural gas tended to increase in the sensitivity case with high carbon-allowance prices. Gas use declined in the Double EE case. More gas was used in the cases in which gas prices were low.

- Electricity production from gas-fired peaking units doubled and in some cases tripled relative to the common set of assumptions in which gas-peaking capacity was added (in Scenario #1); when carbon prices were assumed to be high, which caused gas use in peaking units to rise by about 50%; and when demand response was doubled (again, since demand response only reduced the peaks and did not add much energy-producing or energy-saving resources). The use of peaking units to produce large quantities of electric energy, which the units are not designed for, also increased electric energy prices.

5.2.1.2 Oil Use and Power Production

Oil use for power production did not vary significantly across the scenarios and sensitivity cases:

- Residual fuel oil (heavy fuel oil)—Across almost all the cases analyzed, except Scenario #2 (demand side), residual fuel oil was used minimally in New England; under 500,000 MWh of electricity was generated by heavy fuel oil. The main exceptions are cases in which the oldest generating units in the region were assumed to retire, which eliminated power production by residual oil, or when gas prices were assumed to be higher and thus moved significantly above heavy oil prices. With high gas prices, the use of residual oil rose from the negligible 500,000 MWh amount in the base case to about 33 million MWh, depending on the scenario or sensitivity case. This further suggests the potential value of the residual oil units in the fleet replacing a substantial amount of gas-fired generation if either price or supply interruptions affect the availability of natural gas.

- Distillate fuel oil (light fuel oil)—The use of light oil in peaking units is relatively constant across the cases (about 40,000 MWh), except in two sets of circumstances:

  - When retirements of older plants were assumed to occur, which caused the increased use of oil-fired peaking units (producing about 57,000 MWh of output)

  - When demand-response measures were adopted, for which oil use in peaking units rose considerably, relative to other cases (to about 85,000 MWh in Scenario #2 and to about 130,000 MWh in the sensitivity analysis in which demand-response capacity was doubled)

These demand-response effects resulted from the addition of demand-response capacity for peak-shaving purposes; thus, no other capacity was added to supply compensatory energy production. As a result, a significant portion of the region's oil-fired peaking units remained in place and produced electricity more often than might otherwise have occurred in the other scenarios that provided more electric energy at lower cost than these oil-fired units.

5.2.1.3 Coal Use and Power Production

Overall, the scenarios and sensitivity cases indicate that with a few exceptions, the use of coal in New England, under the assumptions of the analysis, was relatively insensitive to the various capacity expansion scenarios and generated about 25 to 30 million MWh of power. The exceptions to this observation are as follows:

- Scenario #4 (coal IGCC) caused coal-fired power production to rise dramatically to about 63 million MWh—even higher when older power plants were assumed to retire and be replaced with coal capacity (about 76 million MWh).

- When natural gas prices were assumed to be relatively low, gas-fired power plants were dispatched more often and in some cases displaced generation at existing coal-fired power plants (dropping coal production to about 9 to 15 million MWh, depending on the scenario).

- For the high carbon-allowance price sensitivity case, coal-fired power production tended to decline by approximately 5 to 8 million MWh across the scenarios. Low carbon-allowance prices did not cause coal plants to operate substantially more than under the common set of assumptions.

5.2.1.4 Renewables Use and Power Production

The use of renewable resources for power production varied across the cases, largely in direct proportion to the assumptions in each scenario about the amount of renewable resource capacity added. Also, the results were shaped by the assumption in the scenarios cases that "renewables" include a blend of technologies (see Section 4.6). This resulted in a blend of emissions, costs, fuel costs, and so forth, the average results in some cases being quite different from the results for the individual renewable technologies.

For example, renewable power production showed a relative insensitivity to many assumptions about fuel prices and carbon prices, since in the Scenario Analysis exercise, the amount of renewables added to the system was predetermined for each case. That is, output at power plants that used renewable resources (i.e., wind, hydro, PV) was not "dispatchable" in these analyses, since power production by these resources tends to occur when the resources are available (i.e., when the wind is blowing or when the sun in shining on PV systems). To the extent assumed to be available, however, renewable capacity provided power at its operational limits.

The case with the highest renewable power production was Scenario #6 (renewables), which produced approximately 47 million MWh of electricity. Approximately 20 million MWh of this electricity was from existing and new onshore and offshore wind facilities, and about 22.5 million MWh was from other renewables, including fuel cells, hydro, biomass, PV, CHP, and LFG. In other scenarios, renewables produced about 13 million MWh of power.

5.2.1.5 Nuclear Use and Power Production

Overall, nuclear generation was relatively constant across the sensitivity cases, with about 35 million MWh of output at existing nuclear plants in the region. For Scenario #3 (nuclear), however, 5,400 MW of new nuclear generating capacity was installed. In this case, nuclear output rose to about 78 million MWh (and to about 105 million MWh in the case in which the oldest generators in the region retired and were replaced with new nuclear capacity).

As a result of the relatively large and inexpensive energy production and zero emissions associated with the nuclear expansion scenarios, total systemwide emissions were also significantly reduced. These simulation results can also represent the impact of baseload energy-efficiency technologies.

5.2.1.6 Energy-Efficiency Use and Power Production

Because energy efficiency was input directly into the model as if it was a nondispatchable source of supply available in certain amounts in certain hours of the year, the results do not show variations in energy-efficiency "production" associated with fuel prices or carbon-allowance prices. The results also did not capture the expectation that energy efficiency and demand response represent a net reduction in electric energy use at any point in time. Thus, all else being equal, in any particular hour in which the demand-side resources are in place, the overall load should decrease compared with a situation in which that demand-side resource was not available.

As assumed, energy-efficiency measures saved a relatively significant amount of energy (18 million MWh) across the cases. In the sensitivity cases in which the energy efficiency was doubled, this "technology" produced 36 million MWh of "savings." When the older generating units were retired and replaced with energy-efficiency measures and demand response, the amount of energy "provided" by energy efficiency rose to 30 million MWh. The cases showed that an increased supply of energy from relatively inexpensive sources tended to decrease electric energy prices as a result of the displacement of natural-gas- and oil-fired units.

5.2.2 Fuel Dependence (Operable Capacity) Analysis Results

Figure 5-6 shows the results of the operable capacity analysis for both the summer and the winter operating seasons. The analyses demonstrated the continued dependence on gas-fired generation across all scenarios. The results show a need for additional dual-fuel capability for single-fuel gas plants, firm gas supply and delivery contracts, and additional natural gas infrastructure expansion (i.e., gas pipeline enhancements and incremental LNG supply to reduce exposure to reliability issues that could arise from short-term interruptions in domestic or international natural gas supply). For example, for the conditions of the Scenario Analysis, approximately 18,100 MW of natural gas units would need to be available to avoid the use of emergency procedures over the summer peak period. Approximately 10,400 MW of natural gas units with uninterruptible fuel supply would be needed in winter to avoid the use of emergency procedures.

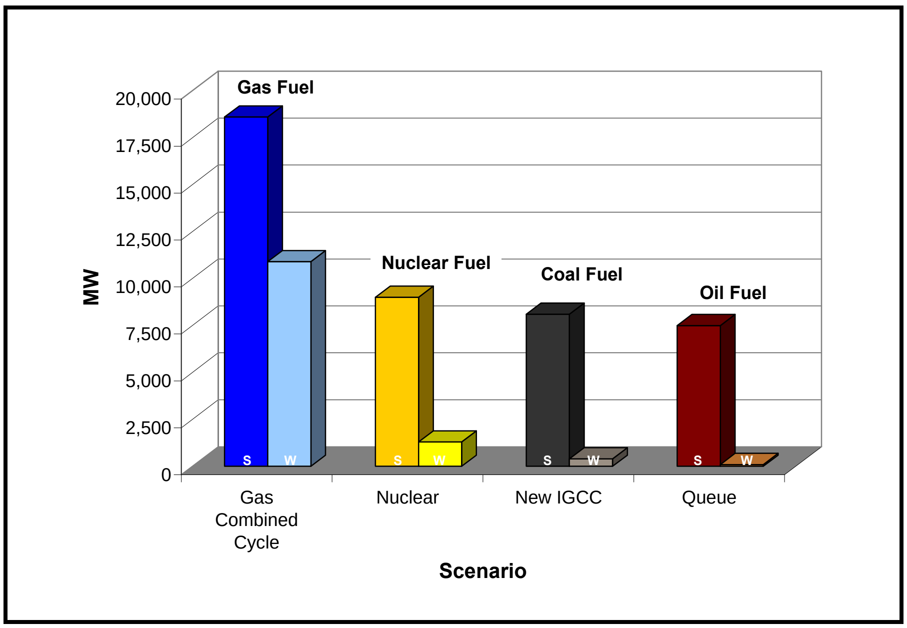

Figure 5-6: Amount of primary fuel type capacity needed to meet summer (S) and winter (W) operable capacity requirements, MW.

The results of the operable capacity analysis also show that under certain scenarios, New England needed to rely increasingly on other expansion technologies besides natural gas—and notably, nuclear, coal, and oil. For these cases, the increased diversity of fuel suppliers (e.g., different sources of imported coal) or the ability to access or import additional resources, possibly from neighboring systems, could mitigate the exposure to fuel-supply disruptions. The extent of exposure to simultaneous outages of nuclear plants could also be mitigated by coordinating maintenance outages and by adding nuclear plants in modular units that are no larger than New England's nuclear fleet included in the recent past.

5.3 Environmental Results

A number of metrics were analyzed to assess the environmental impacts associated with the different scenarios. This comparative discussion focuses on air emissions, although a few other environmental impacts are also discussed.

5.3.1 Air Emissions

The levels of SO_2, NO_X, CO_2, and Hg emissions associated with the different scenarios are directly tied to the type and amount of fossil fuel used to generate electricity for the different scenarios and cases analyzed.

5.3.1.1 Sulfur Dioxide Emissions

Figure 5-7 shows total annual SO_2 emissions (thousand tons) for each of the scenarios, grouped by sensitivity case. The results show that SO_2 emissions, which are driven primarily by the addition of coal to the region's energy supply mix, were highest for Scenario #4 (coal IGCC). SO_2 emissions were highest in absolute terms when gas prices were high and gas plants ran less frequently than under either the common set of assumptions or the low-gas-price assumptions. In fact, SO_2 emissions approximately doubled in the high-gas-price case relative to the common set of assumptions. SO_2 emissions increased from the low-gas-price sensitivity case to the high-gas-price case by over 100,000 tons for all expansion scenarios. SO_2 emissions decreased in the retirement cases, in which older plants, many of which burn coal and heavy oil, were retired and replaced with newer and—in most scenarios—lower-emitting power plants. Some of the technologies within Scenario #6 (a blend of renewables), like wind, had no emissions, while others (e.g., biomass, landfill gas, natural gas fuel cells) had some emissions.

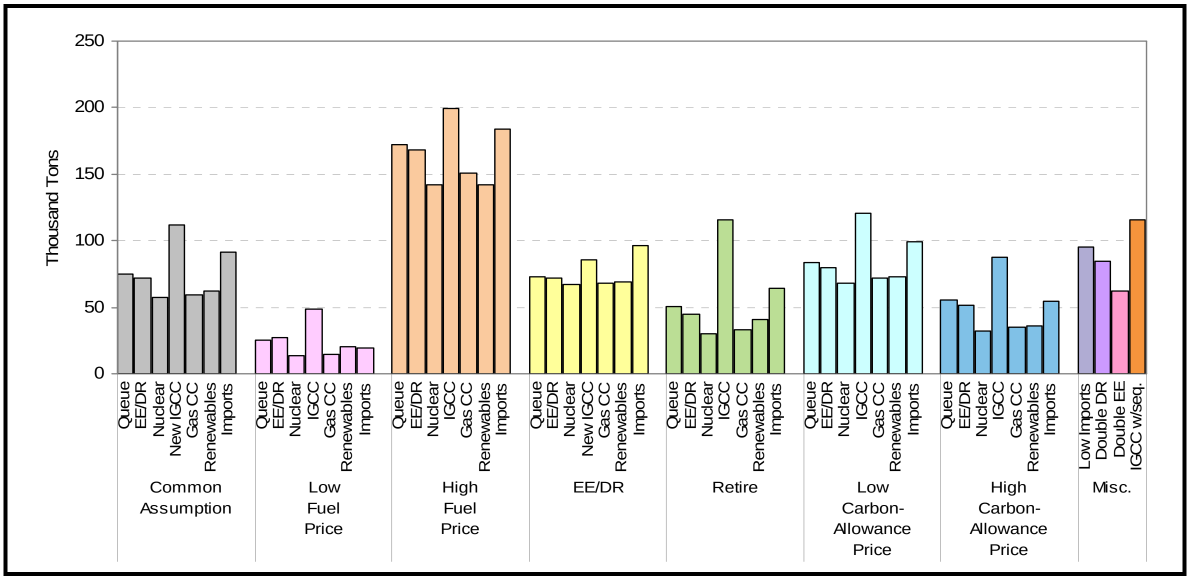

Figure 5-7: Total annual SO_2 emissions, grouped by sensitivity, thousand tons.

5.3.1.2 Nitrogen Oxides Emissions

Figure 5-8 shows that total annual NO_X emissions (thousand tons) followed a somewhat parallel pattern as those for SO_2. Total annual NO_X emissions were significantly higher in general when gas prices were high relative to oil. This is because gas-fired power plants, which have lower NO_X emissions rates than oil plants, operated less often than in other cases. Conversely, NO_X emissions were significantly lower when gas prices were low and in the cases in which older generating units were retired and replaced with newer, more efficient power plants that have lower NO_X emissions rates.

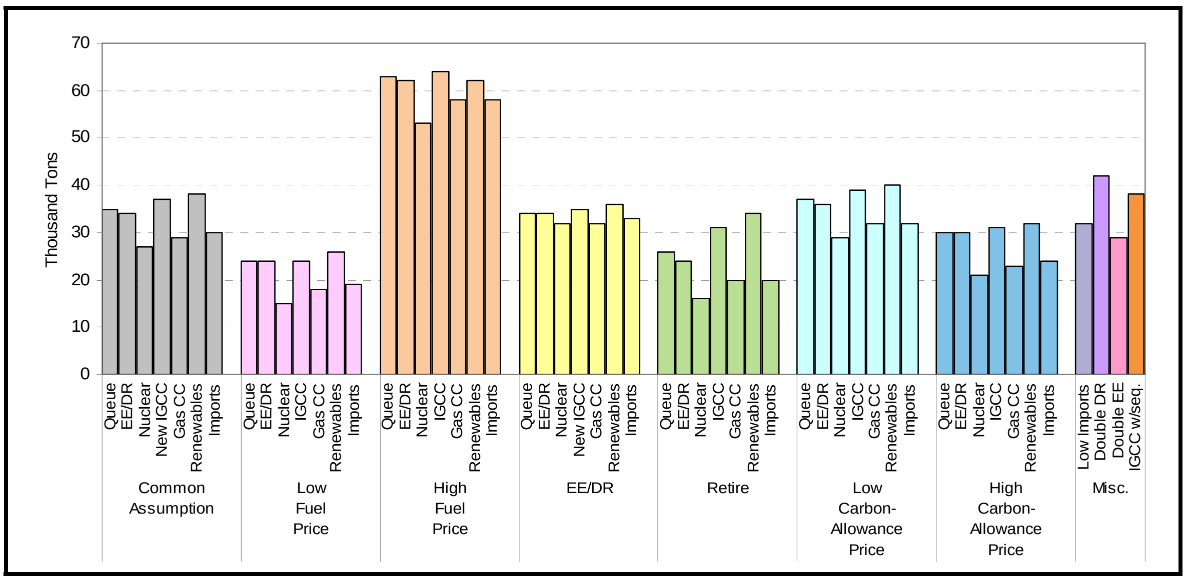

Figure 5-8: Total annual NO_X emissions, grouped by sensitivity, thousand tons.

The scenarios and sensitivity cases also were examined by tracking the amount of NO_X emissions produced on the 10 days that had the highest NO_X emissions. Figure 5-9 shows the NO_X emissions by fuel category for Scenario #2 (energy efficiency and demand response) on the peak-load day of 35,000 MW under the common set of assumptions. The figure shows that hourly emissions were low overnight and in the morning and rose as demand increased.

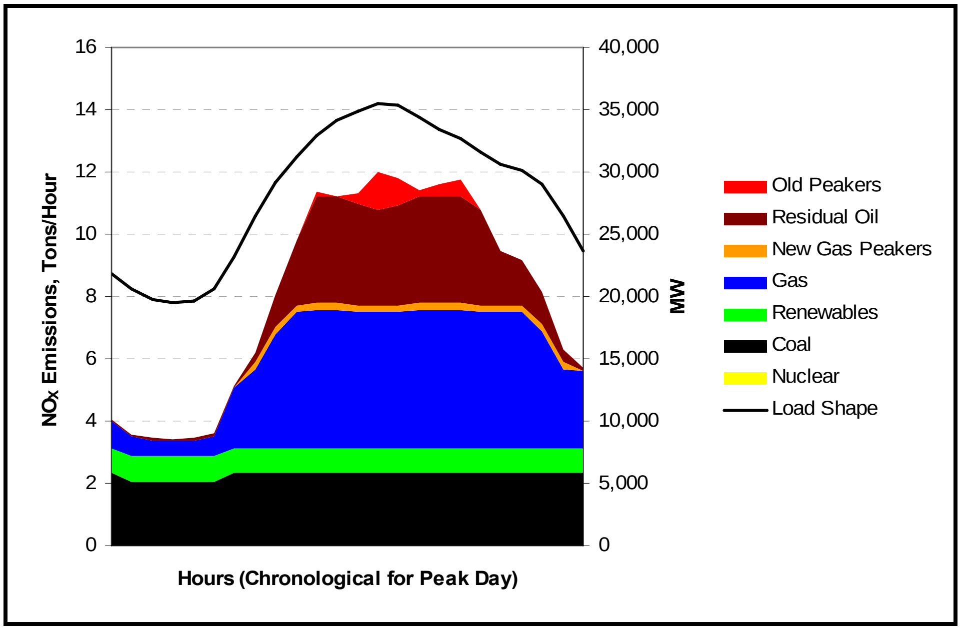

Figure 5-9: NO_X emissions by fuel category on the 35,000 MW peak-load day for Scenario #2 (energy efficiency and demand response) common-assumptions case, tons/hour.

Notes: Solid areas of the figure relate to the left axis. The load shape relates to the right axis. Several resources do not emit NO_X, including nuclear, wind, PV, demand response, and energy efficiency.

Emissions also tended to be lowest in the scenarios with capacity additions that reflected low-emitting/high-energy-producing capacity, such as Scenario #3 (nuclear), Scenario #5 (NGCC), and Scenario #7 (imports). Scenario #2 (energy efficiency and demand response) and Scenario #6 (renewables) had higher NO_X emissions than those other cases. This is because in these scenarios, the capacity additions (specifically, demand response and wind) had lower energy output per unit of on-peak capacity added; thus, other fossil fuel generating units on the system needed to operate more than in the other cases.

5.3.1.3 Carbon Dioxide Emissions

Figure 5-10 shows the total New England CO_2 emissions estimated for each scenario, grouped by sensitivity case. The different scenarios produced varied patterns of CO_2 emissions, in large part depending on the degree and type of fossil-fuel-fired generation dispatched in the scenario and the portion of generation that came from coal. Therefore, Scenario #4 (coal IGCC) had the highest CO_2 emissions (over 90 million tons annually). The other scenarios produced lower CO_2 emissions in the following order: Scenario #1 (queue), Scenario #5 (NGCC), Scenarios #2 and #6 (demand side and renewables), and Scenario #7 (imports). Scenario #3 (nuclear) had the lowest CO_2 emissions, 53 million tons. The ranking relates directly to the relative amount of zero-emitting electric energy produced by the capacity added in each scenario.

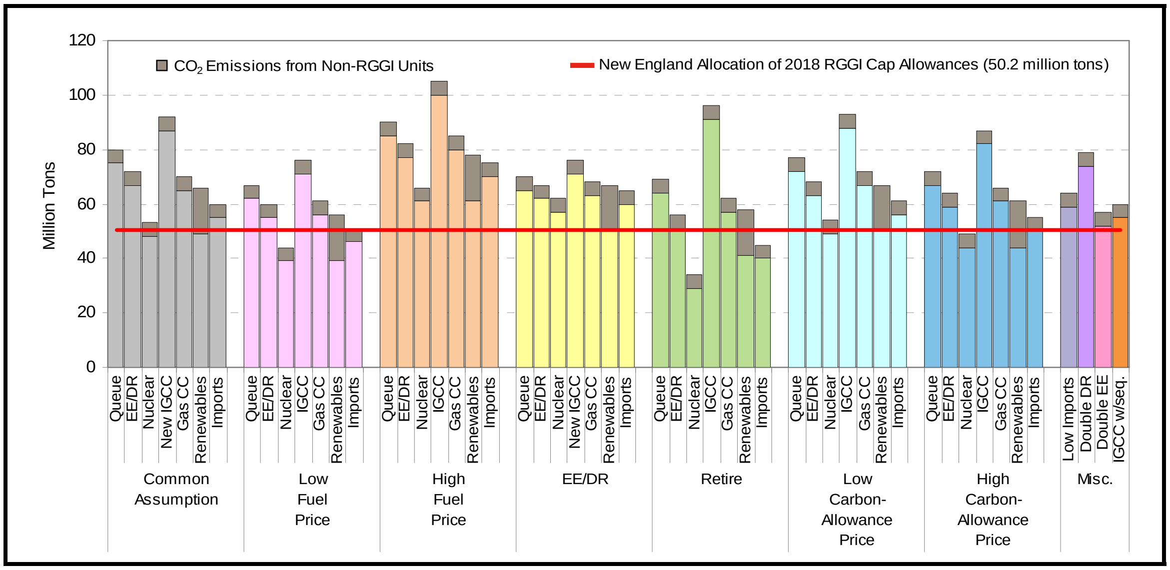

Figure 5-10: Total annual CO_2 emissions, grouped by sensitivity case and showing the New England allocation of the 2018 RGGI cap allowances.

Note: Table includes emissions for units that are not obligated to comply with RGGI requirements.

The case with high fuel prices resulted in the highest CO_2 emissions. For Scenario #3 (nuclear), emissions increased from 53 to 66 million tons, and for Scenario #5 (coal IGCC), emissions increased from 92 to 105 million tons. The retirement sensitivity cases tended to lower CO_2 emissions relative to other cases, except for the coal IGCC case. The higher carbon-price sensitivity cases reduced CO_2 emissions somewhat relative to the common set of assumptions.

Figure 5-10 also shows the CO_2 emissions associated with each scenario and case compared with an emissions level equivalent to the RGGI program's 2018 CO_2 emission allowance for the six New England states (50.2 million tons). The RGGI unit emissions are based on applying the total CO_2 emissions adjustments (see Section 2.2.3), which reduced the emission results shown in Figure 5-10.

Table 5-3 shows the cases that would have systemwide CO_2 emissions below the RGGI cap allocation for New England. Importantly, the RGGI cap does not require power plants in each RGGI state to limit their total emissions to the amount of the allowances allocated for free to each state. The total emissions in the 10 states will be capped and reduced over time; emissions in subparts of the 10-state area may be higher or lower than some "pro-rata" share of regionwide emissions. Plus, trading carbon allowances will be possible throughout the RGGI region, and allowances can be banked and offsets used to help reduce carbon emissions.

Table 5-3
Scenarios and Cases That Appear to Have CO_2 Emission Levels Below the RGGI 50.2 Million Ton Cap for New England

Scenario	Scenarios and Cases
1. Queue	None
2. EE/DR	None, although the Double EE case is close[(a)]
3. Nuclear	All cases except the high-fuel-price case and the case to replace 3,500 MW with energy efficiency and demand response
4. Coal IGCC	None
5. NGCC	None
6. Renewables	All except the high-fuel-price case
7. Imports	Low-fuel-price case; the case to retire 3,500 MW; and the case with the high-CO_2-allowance price

(a) The results for the retirement sensitivity case indicate that, under these assumptions, adding energy efficiency could result in total CO_2 emissions that are below the allocation for the New England states.

5.3.1.4 Mercury Emissions

As expected, the results show that mercury emissions were highest in coal-fired Scenario #4 (coal IGCC) and produced about 3,000 lb of mercury annually under the common set of assumptions, about 3,600 lb/year in the retirement sensitivity case, and about 1,500 lb/year in the low-gas-price case. Other scenarios produced far less mercury. Mercury controls in place on coal plants that yield a 90% reduction would bring these amounts to within proposed mercury regulations.

5.3.2 Other Environmental Metrics

The percentage of output from renewable energy was 12.9% for Scenario #1 (the queue); 12.9% for Scenarios #2 (demand side), #3 (nuclear), #4 (coal IGCC), and #5 (NGCC); 27.2% for Scenario #6 (renewables); and 26.4% for Scenario #7 (imports). These results indicate whether the scenarios would be able to meet the RPS requirements, which may be 20 to 25% by the 2020 to 2025 period.[91]

The number of acres of land needed in New England for siting new facilities (generating units and transmission) is shown in Table 5-4. The table does not indicate the extent of possible dual uses of land when siting transmission lines and wind generators. The land requirements also do not reflect the expansion of the regional natural gas infrastructure.

[91] For example, New Hampshire, the last state in New England to establish an RPS, has set the highest target among the six states: 25% by 2025 (which is exclusive of in-state large-scale hydro that currently generates the equivalent of about 10% or more of the electric sales in New Hampshire). Also note that Connecticut classifies gas-fueled fuel cells and CHP as "renewable" sources of energy and includes them in its RPS percentages. Connecticut's *Act Concerning Electricity and Energy Efficiency* (January 2007) extends the Connecticut RPS Classes I and II requirements to increase to a total of 20% by 2020. See the *DSIRE Database* for more information on each state's RPSs. Also see additional information on NH's RPS Act.

Table 5-4
Low and High Incremental Land Requirements in New England for the Scenarios, Acres

Scenario	Generation	Transmission	Total
1. Queue	9,134–54,008	238–6,019	9,371–60,027
2. EE/DR	0	0	0
3. Nuclear	1,038–2,025	238–6,019	1,276–8,044
4. Coal IGCC	393–2,700	238–6,019	631–8,919
5. NGCC	128–128	238–950	365–1,070
6. Renewables[(a)]	123,749–227,547	2,257–13,781	126,006–241,327
7. Imports[(b)]	0	11,880–29,462	11,880–29,462

(a) These results were based on the assumed composite blend of renewables; individual renewable projects would involve more or less land.

(b) Additional incremental land requirements would likely be necessary outside New England for generation and transmission.

The amount of water required for wet-cooling the power plants included in the large-expansion scenarios are as follows:

- Queue scenario (#1)—12,100 gal/minute
- Nuclear scenario (#3)—85,200 gal/minute
- Coal IGCC scenario (#4)—65,900 gal/minute
- NGCC scenario (#5)—20,700 gal/minute

The scenarios not listed had less significant cooling requirements.

A savings is associated with energy-efficiency and demand-response resources compared with supply-side resources in that no additional transmission expansion was assumed to be needed. Scenario #2 (demand side) also reduced the amount of distribution system investment costs in the range of $100 million to $325 million.

Section 6
Key Themes and Conclusions

This section summarizes some of the main results and conclusions of the Scenario Analysis. In general, the stakeholder process provided valuable input, including the review of the scope of work, assumptions, and draft results. The report provides a great deal of information that regional stakeholders can use for evaluating resource alternatives. The posting of data and spreadsheets should facilitate the ability of stakeholders to develop their own results and conclusions.

Key themes that emerged from the results of this analysis are as follows:

- Lower electric energy prices and reduced air emissions are possible by reducing demand or supplying high amounts of electric energy that have low or no fuel costs and that emit few pollutants.

- New England will continue to be highly dependent on natural gas power production.

- Energy prices and air emissions will be strongly influenced by the relative costs of natural gas and oil.

- The power sector will need to follow various strategies to meet the region's goals for reducing CO_2 emissions.

6.1 Key Results

The key themes of the economic, reliability, and environmental results based on the series of assumptions used in this boundary analysis are summarized in the following sections.

6.1.1 Themes of the Economic Results

- ***The price of fossil fuels (natural gas and oil) was the most dominant factor affecting the costs and emissions for each of the scenarios.*** This can be seen in Figure 5-3 (p. 51) and Figure 5-10 (p. 65) for the LSE expenses for wholesale electric energy and total CO_2 emissions, respectively. The absolute and relative levels of natural gas and oil prices tended to be the biggest factors affecting the amount of electricity produced by different technologies, total systemwide expenditures for energy production, and total amount of emissions produced by power plants. For example, the sensitivity case for which natural gas price doubled also showed increases in wholesale energy costs to LSEs of approximately 50% across all scenarios. This same sensitivity case increased systemwide CO_2 emissions by more than 10 million tons for every scenario compared with the cases under the common set of assumptions. Fuel prices affected the energy mix, costs, and emission levels. The simulations demonstrated that an increase in gas prices (relative to oil prices) could lead to a rise in emissions because power plants would burn more oil. This effect would be moderated in practice because higher electricity prices typically cause consumers to conserve and suppliers to invest in more efficient technologies. If gas shortages were to occur, the system would be exposed to fuel interruptions and increased commodity prices, which would in turn expose New England to greater electric energy price volatility and reliability problems. This result is nothing "new" but a reality confirmed by the modeling of the various scenarios under different assumptions about fuel prices, carbon emission allowance prices, and other factors.

Given the inherent difficulty in predicting what future oil and gas prices will be, the addition of infrastructure in the regional natural gas supply and delivery systems and reductions in gas sector demands could mitigate price volatility during periods of high demand. Several demand-side technologies (e.g., efficient gas-fired heating systems; additional home insulation; heating, ventilation, and air-conditioning environmental controls) could provide the dual benefits of reducing the demand for both natural gas and electricity while reducing prices for both products.

- ***Under the assumptions of this analysis, most of the technologies evaluated needed more investment support than what the energy spot markets alone provided.*** Only energy-efficiency resources (such as in the sensitivity case that doubled energy efficiency) and some technologies in Scenario #1 (the queue) showed sufficient revenues from just the energy spot market and capacity markets to economically justify investment. Other technology types (e.g., wind, nuclear) showed a heavy dependence on non-energy-market revenues to be economically viable. For example, wind and nuclear resources tended to have high capital costs, which caused them to be relatively expensive to build. These technologies showed a modest to significant gap between the net revenues these technologies received in the New England wholesale electric energy markets and annual revenue requirements associated with investment. Therefore, to induce investment in these technologies and have them enter the market, some other means would be needed to fill this revenue gap, such as through Forward Capacity Market payments; the provision of ancillary services; tax credits; the sale of emission allowances; Renewable Energy Certificates; long-term purchased power agreements for electric energy, capacity, or both; counting capital costs in the rate base; the outcomes of any new regulatory requirement; and other sources.

- ***Adding significant demand-side resources provided capacity and energy benefits to the system.*** Energy efficiency lowered peak-demand growth and electricity demand across the many hours of the year and provided energy "savings" and emission benefits to the system. Demand-response resources, which have operating characteristics that are similar to peaking units, tended to provide capacity but less relative electric energy to the system in other hours. Other demand resources, such as energy efficiency, have operating characteristics that are similar to baseload or intermediate units and thus provided both capacity and energy savings. Much—if not a majority—of the savings from energy efficiency should flow to consumers.

- ***In the context of this analysis, energy efficiency and demand response showed sufficient revenues (or savings) from the wholesale electric energy and capacity markets to economically justify investment.*** Additional natural-gas-fired generators also may be economic capacity additions. Other technology types (e.g., wind, nuclear) showed a heavy dependence on non-energy-market revenues to be economically viable. The results for Scenario #7 (imports) also showed net energy market revenues and assumed capacity revenues that exceeded the annual revenue requirements for building transmission within New England. However, added costs for building transmission, hydro facilities, or other types of resources in neighboring systems to produce and transmit the energy could substantially change the economic evaluation of the import scenario.

- ***Adding large amounts of resources that produced large amounts of electric energy and had low operating costs and low emissions reduced systemwide production costs, energy prices, and emissions.*** Compared with Scenario #1 (the queue), the expansion technologies in all the other scenarios that provided substantial electric energy to the system had lower average marginal prices, lower average overall energy-related costs, and lower emissions (see Table 5-1, p. 50). For example, wind, imports from neighboring systems, nuclear, and energy efficiency (and double energy efficiency), all of which provided energy—or energy savings—at low to no fuel cost, resulted in the lowest systemwide electric energy prices, emissions, and use of fossil fuels. Other results and conclusions are as follows:

    - Electric energy clearing prices in all cases except Scenario #2 (demand side) were lower than the queue case.
    - The results of the simulations do not reflect dynamic changes, for example, (1) lower gas prices, which could materialize in energy-efficiency cases and reduce the demand for natural gas; or (2) higher gas prices that could result from scenarios that increase regional gas demands (e.g., NGCC).
    - New gas-fired resources on the margin would be more efficient than older, existing resources and would tend to reduce clearing prices compared with existing marginal gas-fired resources that had set average clearing prices in the past.
    - Scenarios, such as Scenario #1 (the queue), that largely depend on peaking and fast-start resources, are likely to lead to higher average energy prices.

- ***Natural gas will remain the marginal fuel.*** In all cases under the common assumptions, natural-gas-fired power plants remained on the margin approximately 90% of the time. Even after adding 5,400 MW of a new technology type (combined with the 2,600 MW of new capacity in the queue), natural-gas-fired plants typically were the power plants last dispatched to meet demand in most hours of the day. This held across virtually all assumed cases. Therefore, average clearing prices in New England's wholesale electricity markets tended to be more dependent on natural gas fuel costs than the costs of the different expansion technologies used in the scenario analysis cases (see Figure 5-2, p. 50).

- ***Additional transmission and distribution investment may be needed to support various technologies, depending on where actual resources are added in the future.*** To a limited degree, the Scenario Analysis examined the transmission implications of different types of resource technologies for the system and found that incremental investments may well be needed to support the system's transmission and distribution needs in the future. For example, significant transmission investment would be needed in New England under the import scenario, and, while not modeled, it also would likely be needed in Canada. Because it is not known where any actual demand-side or supply-side resources might actually develop, the Scenario Analysis used simplifying assumptions about transmission and distribution costs.

6.1.2 Themes of the Reliability Results

- ***The system capacity mix did not alter a high dependence on natural-gas-fired capacity under any scenario.*** Adding large amounts of different types of incremental capacity did not radically change the overall mix of gas-fired capacity in New England. This is largely because each of the cases assumed that the 5,400 MW of one technology type was added to a base of approximately 31,000 MW existing in 2007 plus 2,600 MW of resources reflecting a mix of fuels in the Generator Interconnection Queue. Of the total 39,000 MW of resources, a minimum of 13,900 MW used natural gas as a fuel. Therefore, even adding a deliberately large quantity of a single non-gas technology or fuel type did not eliminate the already strong dependence on natural-gas-fired units in the region.

- ***The greatest changes in the capacity mix tended to occur in the sensitivity cases that assumed that the oldest 3,500 MW of generating capacity in the region were retired and replaced with that scenario's core technology.*** For Scenario #5 (NGCC), natural-gas-fired unit capacity constituted 50% of the total systemwide capacity of almost 39,000 MW. This grew to 58% of the overall capacity in the retirement sensitivity case. By comparison, in the other scenarios, natural gas capacity constituted approximately 35% of the total systemwide capacity, even in the retirement sensitivity case.

- ***Adding thousands of megawatts of demand-response capacity, as assumed in this Scenario Analysis, could lead to trade-offs.*** Although demand-response resources can shave peak loads at relatively low costs compared with other resources and can provide other benefits not fully analyzed in this report (i.e., provide operating reserves, reduce price spikes and congestion, reduce emissions produced by existing fossil-fired peaking generators), adding "too much" peaking capacity at the exclusion of resources with more baseload characteristics may lead to higher wholesale electric energy prices and greater emissions.

6.1.3 Themes of the Environmental Results

- ***With the exception of the Scenario #4 (coal IGCC), the retirement case results showed lower emissions among most of the sensitivity cases.*** Compared with the results for each scenario under the common set of assumptions, the results for the sensitivity analyses that involved the retirement of the oldest generating capacity in the region showed fewer emissions of nitrogen oxides, sulfur dioxide, and carbon dioxide and lower production costs and oil consumption. These results tended to occur across all scenarios that applied the retirement assumption. These scenarios also needed to add more capacity to make up for the retired units.

- ***New England's CO_2 emissions from the power sector varied considerably across the scenarios (and within some scenarios, depending on the assumptions about such things as fuel prices, emission allowance costs, and retirement).*** The results show that even subtracting emissions associated with the plants not covered under the RGGI program, the emissions from New England's power sector exceeded 50 million tons in most scenarios. Thus, reducing the region's CO_2 emissions as part of complying with the Regional Greenhouse Gas Initiative would seem to require some combination of adding substantial amounts of low- or zero-CO_2-emitting resources, having RGGI-affected power generators buy additional CO_2 allowances or use previously banked ones, buying offsets from outside the electricity sector, redispatching the electric system to burn fossil fuels more efficiently (or not at all), retiring some power plants that emit substantial quantities of CO_2 emissions, switching fuels, increasing imports, or using some economic combination of these approaches.

- ***Adding more renewables with no or low CO_2 emissions in areas far from load centers or importing more hydroelectric power may necessitate the construction of substantially more transmission in the region to move this power to the load centers.*** The locations for potentially developing renewable resources are likely remote from the New England load centers. For example, transmission development will be needed to integrate offshore wind projects into the New England transmission system. Similarly, the potential sites for developing onshore wind tend to be in northern New England, while much of the region's load is concentrated in southern New England. The analysis accounted for conceptual transmission costs for the scenarios that included new wind resources, imports from neighboring systems, and the development of fossil-fuel and nuclear resources within New England (which was assumed could be located close to load). To the extent that new resources within New England would be remote from the load or outside any congested interfaces, these costs could arise.

- ***A relatively high reliance on peaking resources, whether fossil-fuel-based or emission-free demand-response resources, increased overall air emissions.*** Both demand response and generation turbines are peaking resources and are not good substitutes for such energy resources as baseload generation or energy efficiency. The scenarios and sensitivity analyses that included a significant increase in demand response to shave demand during hours of peak energy use also produced relatively high levels of air emissions (NO_X, SO_2, and CO_2,), oil use, and production costs. This is because, in these cases, other power plants—typically some combination of plants that run on fossil fuels—operated in more hours than in other scenarios. In Scenario #2 (2,700 MW of demand response and 2,700 MW of energy efficiency) and in the sensitivity analyses involving even greater additions of demand response, the reduced capacity needs provided by demand response offered little relative savings in electric energy production. This effect can be seen most dramatically in the cases in which demand response replaced energy efficiency, which showed higher emissions, production costs, and fossil fuel use than in cases in which energy efficiency provided the same capacity but considerably more electric energy (see Figure 5-9, p. 64).

6.2 Concluding Comments on the Scenario Analysis Process

The Scenario Analysis initiative was designed to provide the region with information about the implications of various choices for meeting consumers' future needs for reliable, competitively priced, and environmentally sound supplies of electricity. Rather than creating a long-run regional energy plan, the ISO carried out this exercise to shed light on possible outcomes of pursuing one particular technology versus another. Examining the detailed results of the Scenarios Analysis helps to reveal the implications of what different investment options might mean for the region and the resultant impacts on the cost to produce electricity, electricity prices, electric power supply reliability, fuel diversity, the environment, and other metrics of interest.

These "what if" analyses have inherent constraints on the type of information they can provide to the end user. Quantitative models and other tools are limited in their ability to depict how a system would actually perform if the assumed conditions occurred in the future, to predict how the electric power system would interact with other elements of the economy, and so forth. These are complex systems, and no model can simulate their performance with complete accuracy. Because of the technical limitations of the tools of prediction (as well as time and other resource constraints), the assumptions about key elements of the system were simplified. The results generated are thus informative about rather than predictive of how future electric technology choices will play out in the region. The results should be viewed as providing directionally appropriate information, while not necessarily providing detailed and “accurate” information.

One of the more significant simplifications was that the model did not include a network or account for congestion. As a result, resources that can be easily located in congested areas, such as energy efficiency, may be more economic than represented here. Another simplification was that the model assumed the markets would be perfectly competitive and thus that electric energy offers would be at marginal cost. This, like the lack of congestion, tends to bias prices low. This would especially be true over multiple years as consumers invest in more efficient equipment as clearing prices rise. Both of these effects moderate prices and emissions. Finally, the scope of the Scenario Analysis did not include extensive modeling of the trade-offs between investments in generation and transmission. The levels of investment in transmission will affect the generation mix. For example, less investment in transmission tends to lead to more peaking resources within the congested areas.

The results can be helpful in providing insights for others in conducting more detailed studies and for more in-depth policy analysis and discussion about the technologies that hold particular interest or value for the region. The ISO encourages interested parties to compare the results of the outcome metrics for the different scenarios and reach their own conclusions about the various technology outcomes.

6.3 Use of the Data

The Scenario Analysis produced volumes of detailed information about the impacts of the potential technology outcomes on the region’s future electric power system. This report provides the tip of the “information iceberg” that is available about the scenarios; their economic, environmental, and reliability impacts; and how those impacts change under different sets of assumptions. The complete results are available to the public on the ISO’s Web site. Potential users may access the data to gain a more complete view of the estimated impacts of the seven core scenarios and the many sensitivity analyses performed on them.

Readers who want to use the results of the Scenario Analysis to carry out further investigations can use a spreadsheet tool posted on the ISO’s Web site. With this tool, stakeholders can “mine” the information, make other investigations, and even explore the impacts of making different assumptions. The spreadsheet tool allows the user to adjust, for example, “post-processing” assumptions about capital costs of the generating resource or demand-side measures, needs and costs of the transmission and distribution systems, and the costs of carbon sequestration. The user, however, cannot rerun the production simulation model with different assumptions. The spreadsheet on the Web site is accompanied by instructions to assist users in understanding the capabilities of the tool and the assumptions that users will be able to change.

Table Citations

Table Reference	Description
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