2006 Regional System Plan

Approved by the ISO New England Board of Directors

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Executive Summary

ISO New England Inc. (ISO) is the not-for-profit corporation responsible for the reliable operation of New England's bulk power generation and transmission system. It also administers the region's wholesale electricity markets and manages the comprehensive planning of the regional bulk power system. The planning process is open and transparent and involves advisory input from regional stakeholders, particularly, members of the Planning Advisory Committee (PAC).[1]

Each year, the ISO prepares a comprehensive Regional System Plan (RSP). These 10-year plans include forecasts of future load (i.e., the demand for electricity measured in megawatts, MW) and how the system as planned can meet the demand by adding generating resources, demand-side resources, and transmission.[2] Each plan addresses systemwide needs and the needs in specific areas to ensure the reliability of the system as well as compliance with national and regional planning standards, criteria, and procedures. Each plan also includes information that serves as input for improving the design of the markets and the economic performance of the system. In addition, these plans summarize the ISO's short- and long-term initiatives and other actions the ISO, transmission owners (TOs), other market participants, state officials, policy makers, and other regional stakeholders can take to meet the needs of the system.

The ISO's *2006 Regional System Plan* (RSP06) presents the results of load, resource, and transmission studies for New England's electric power system through 2015. The plan accounts for uncertainties in assumptions about this period related to changing demand, fuel prices, technologies, market rules, environmental requirements, and other relevant events. The major findings of RSP06 are as follows:

- **Capacity—**Additional installed capacity (ICAP) is needed in New England by 2009 to assure that the system meets its resource adequacy standard.[3,4] The addition of fast-start resources in transmission-constrained areas would improve system security and reduce reliability costs to

[1] The PAC is a regional forum for interested parties that helps the ISO assess and develop the Regional System Plans and conduct system enhancement and expansion studies. Additional information about the PAC is available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/index.html.

[2] *Demand-side* resources are those that reduce consumer demand for electricity from the bulk power system, such as by using energy-efficient equipment, conserving energy in other ways, and using electricity generated on site (i.e., distributed generation or DG) (see Section 6.4.4). Some demand-side resources reduce load in response to a request from the ISO to do so for system reliability reasons (called *demand response)* or in response to a price signal (called *price response*) (see footnote below and Section 5.2.1). *Other demand resources* (ODRs) are demand-side resources outside the ISO's control.

[3] *Installed capacity* is the megawatt capability of a generating unit, dispatchable load, external resource or transaction, or demand-side resource that qualifies as a participant in the ISO's ICAP Market per the market rules. See http://www.iso-ne.com/rules_proceds/index.html.

[4] 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. For additional information about the criterion, see http://www.npcc.org/criteria.asp.

consumers.[5] Environmental regulations will likely encourage the development of "clean" resources that will help meet system capacity needs.[6]

- **Fuel Diversity—**Because the region relies heavily on natural gas to generate electricity, a significant amount of that generation must be able to use an alternate fuel to stabilize costs to consumers throughout the year and to assure system reliability in the winter months when the use of natural gas to generate electricity competes with home-heating needs.[7] The addition of "clean" resources will assist in diversifying the fuel supply.
- **Cost Impacts—**The region's reliance on natural gas also links the price of electric energy to the price of natural gas. Having a balanced mix of fuels that includes adding baseload generators with low marginal production costs (relative to a typical unit that burns natural gas or oil) is one way to control consumer electric energy costs and reduce electric energy price volatility associated with these fuels. Increased conservation, energy efficiency, and demand response are additional strategies to control these costs and price volatility.[8]
- **Transmission—**Transmission upgrades are required throughout New England to maintain system reliability, simplify system operations, increase system transfer capability, serve major load pockets, and reduce locational dependence on generating units.[9]

The primary results of RSP06 show that New England will require new resources by 2009 across the system and specifically in major load pockets, especially Greater Connecticut and Greater Southwest Connecticut (SWCT).[10] The specific minimum and maximum amounts, locations, timing, and characteristics of these resource requirements will be influenced by improvements to the markets, new environmental regulations, the growth in demand, and transmission system constraints. Without the timely addition of new resources, the region will fail to meet established reliability criteria, increasing the possibility of needing to disconnect customers during periods of peak demand.

To meet system capacity requirements, RSP06 emphasizes the importance and value of applying short-lead-time conservation, energy-efficiency, and demand-response measures to reduce demand. It also encourages the addition of fast-start generators needed for the economical and secure operation of transmission-constrained load pockets. Improvements to the markets have been designed to provide the incentives for attracting resources needed to continue to reliably meet demand. On the basis of the Forward Capacity Market (FCM) Settlement Agreement, approved by the Federal Energy Regulatory Commission (FERC) in June 2006, the FCM is being designed to accomplish several tasks to enhance system capacity.[11] These include encouraging the development of new supply-side

[5] *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.

[6] "Clean" resources emit no or low emissions when generating electricity compared with fossil fuel units.

[7] *Dual-fuel* units have the flexibility and storage capacity to use fuel oil as well as natural gas.

[8] *Demand response* refers to the reduction of electricity consumption in response to system reliability events in exchange for compensation based on wholesale electricity prices.

[9] *Load pockets* are areas of the system where the transmission capability is not adequate to import capacity from other parts of the system, and demand is met by relying on local generation (e.g., Southwest Connecticut and the Boston area).

[10] To conduct some RSP studies, the region is divided into various areas related to their electrical system characteristics. Greater Connecticut is an area that has boundaries similar to the State of Connecticut but is slightly smaller because of electrical system limitations near Connecticut's borders with western Massachusetts and Rhode Island. Greater Southwest Connecticut includes southwestern and western portions of Connecticut.

[11] Devon Power LLC, *Order Accepting Proposed Settlement Agreement,* Docket Nos. ER03-563-030 and ER03-563-055, 115 FERC

and demand-side resources, providing incentives to improve the availability of existing resources in times of greatest system need, and compensating participants that provide the needed resources. A locational Forward Reserve Market (FRM), approved by FERC in May 2006, is expected to be in service in the fourth quarter of 2006.[12] This market has been designed to encourage the development of fast-start and demand-response resources.

RSP06 also emphasizes the critical importance of modifying the resource mix in New England to reduce the region's heavy dependence on generation fueled by natural gas and oil. Although significant progress has been made to improve system operations during the winter (when a heavy dependence on natural-gas-fired generation has been problematic) and to increase the region's dual-fuel capability, as the demand for electricity grows, additional dual-fuel capability will be needed. Thus, for the long term, the region must continue to decrease its reliance on natural gas, particularly during winter peak-load conditions. Since the region is likely to continue to depend on natural gas for a significant portion of its electricity, at least for the next several years, generating resources could procure firm natural gas contracts to improve the reliability of the fuel supply. Recent improvements in the electric energy markets should encourage the economic viability of these contracts. To further improve the regional fuel mix, the ISO, with all regional stakeholders, should encourage the addition of economic alternatives to using gas- and oil-fired generation. These alternatives include nuclear energy, renewable generation, such as wind and hydro imports, and new coal technologies.[13]

To illustrate quantitatively the potential effects of ways to reduce wholesale electricity costs, the ISO undertook several calculations. First, to illustrate the potential effects on the wholesale electricity market of moving the resource mix away from gas- and oil-fired resources, the ISO conducted an electric energy and production cost-impact analysis of adding baseload generation (other than natural gas or oil fired) that has low marginal production costs.[14] The results of the analysis show that consumers would have saved about one-half billion dollars in electric energy costs if 1,000 MW of this type of baseload generation had been added to the system in 2005 at prevailing capacity prices.

Second, to illustrate the potential effects of reducing the consumption of electricity, the ISO analyzed the effects of demand reduction on the wholesale market. The analysis shows that reducing demand by 5% during all on-peak hours through energy conservation and energy-efficiency measures would have saved consumers the same amount, about one-half billion dollars on the basis of historical performance for 2005.[15] Reducing the regional peak demand results in using the current and planned power system infrastructure more efficiently, thereby reducing total costs to consumers. A critical step in reducing peak demand is linking the retail rate design with wholesale electricity pricing. This will send time-differentiated price signals to consumers who can then decrease their use of electricity at appropriate times, potentially delaying the need to add new bulk power system infrastructure.

¶61,340 (June 16, 2006). See the ISO's *2005 Annual Markets Report* (AMR05), Section 3.3, for additional information on the FCM (http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html).

[12] New England Power Pool and ISO New England Inc., *Order Accepting Ancillary Services Market Proposal*, Docket No. ER06-613-000, 115 FERC ¶61,175 (May 12, 2006).

[13] In addition to wind energy, renewable resources include small hydro, solar, selected biomass, ocean thermal, and, in some states, fuel cells. Pumped hydro is not considered a renewable resource since a portion of the energy for pumping comes from fossil fuel and nuclear (i.e., nonrenewable) generating plants.

[14] For background information about this analysis, see the ISO's *Electricity Cost White Paper* available at http://www.iso-ne.com/pubs/whtpprs/index.html.

[15] The ISO's *on-peak demand* period is from 7:00 a.m. until 11:00 p.m. on weekdays.

The ISO, with input from its stakeholders, continues to develop a number of major transmission-upgrade plans. These plans have been designed to ensure the continued adequacy and reliability of the transmission system by reducing significant bottlenecks in transferring power into load pockets throughout New England and relieving the dependence on local generation within these pockets. From 2002 to June 2006, 127 projects were completed, representing an investment of $429 million. As of June 2006, 43 of approximately 250 approved projects in the 10-year plan, a nearly $1 billion investment in new transmission infrastructure, are currently under construction. Two major 345-kilovolt (kV) projects will be placed in service by the end of 2006. These projects are the first phase of the NSTAR 345 kV Reliability Project (Phase I) and the Southwest Connecticut Reliability Project (Phase 1) (see Section 1.1.6). The planning of the system has been fully coordinated with neighboring regions, and additional work has begun to investigate increasing import capability from Canada.

1.1 RSP06 Results

Key RSP06 results are as follows; references are included to the sections in which the information is more fully discussed.

1.1.1 Growth in Demand

The growth in demand drives the need to upgrade New England's electric power infrastructure. New England's summer-peak demand is projected to grow at a compound annual growth rate (CAGR) of 1.5% from 2005 to 2007 and 1.9%, or 500 MW to 600 MW per year, in the long run. These growth rates are, in part, a function of the price of electric energy, which reflects natural gas and fuel oil prices. These prices have sharply risen since 2000, but it is assumed they will decline and then stabilize over the long term.[16] In addition, the region's increased use of air conditioning is decreasing the annual load factor (i.e., the ratio of the average hourly load during a year to peak hourly load).[17] This means that the peak hourly load has been increasing relative to average load levels. The annual load factor is expected to continue to decline to 54% by 2015, further indicating the need to add peaking capacity and demand response in the region. (Section 3)

1.1.2 Resource Needs

Resources are needed within the next few years to provide sufficient systemwide capacity, as listed below. When properly sized and located, these resources can also provide critical system support in areas with limited transmission capability, particularly in import-constrained load pockets:

- With 2,000 MW of tie-line benefits, the system will need an additional 170 MW of capacity by 2009 to meet resource adequacy criteria.[18] It will need 4,300 MW by 2015 with the same tie-line benefits. The system would need resources sooner and in greater amounts if not all of the assumed 2,000 MW of tie-line benefits were available or if generating units were retired. Projections of future amounts of tie-line benefits are currently under study and will be subject to stakeholder review. Consistent with planning criteria, the use of operating procedures for responding to a capacity deficiency would be required several times per year, despite the addition of needed capacity. (Section 4)

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[16] From 2000 to 2005, the price of natural gas increased from about $5/million British thermal units (MMBtu) to $9.75/MMBtu, and the price for No. 6 fuel oil increased from $4/MMBtu to $6.70/MMBtu. For more information, refer to AMR05.

[17] The annual load factor was 65% in 1985, dropping to 62% in 2000 and 58% by 2005.

[18] A *tie-line benefit* is the receipt of emergency capacity from a neighboring area.

- Without adding new resources to the system, the frequency and severity of responding to a capacity deficiency would increase over time and vary with changes in demand and other factors. The examination of specific extreme load conditions shows that up to 1,700 MW of relief could be required in 2007 under ISO New England's Operating Procedure No. 4, *Action during a Capacity Deficiency* (OP 4).[19] The ISO's reliance on neighboring systems would increase at the same time that these systems would likely have less capacity available to sell to New England. (Section 4)
- Greater Connecticut needs additional resources, transmission improvements, or a combination of both for reliable system operation and compliance with transmission planning criteria. If import limits into the area do not improve, by 2009 the area would need a minimum of 510 MW of new resources or a reduction in the peak demand of the same amount. This amount would grow to 1,440 MW by 2015. Adding these resources or reducing the load also would potentially defer the need for transmission improvements necessary for reliability. (Section 9)
- Locating generators near areas of relatively high demand provides the capacity needed to meet demand while minimizing the need for transmission expansion. While all generator interconnections are subject to system impact studies that address technical requirements, for enhancing reliability, adding generating units in southern New England (SNE), especially Greater Southwest Connecticut, is generally preferred to locating them elsewhere. Upon completion of the SWCT Reliability Project, the most preferred location for electrically interconnecting new resources will likely be the northern and western areas of the Southwest Connecticut 345 kV system. As demand continues to grow, locating new capacity in the BOSTON area also would assist in meeting total system capacity requirements.[20] However, these interconnections would be subject to electrical system performance constraints. (Section 9)

1.1.3 Operating Reserves and Demand-Side Resources

Beyond needing a certain *level* of resources to reliably meet the region's demand for electricity, the system needs the *type* of resources that can quickly respond to system contingencies related to equipment outages and higher-than-forecast peak demand. These resources provide reserves for maintaining operational control and serve or reduce peak loads during periods of high demand. A lack of fast-start resources in transmission-constrained subareas could require the ISO to use more costly resources to provide these necessary services. In the worst case, reliability could be degraded. (Section 5)

The locational Forward Reserve Market is intended to encourage the development of fast-start and demand-response resources in load pockets to meet these operating needs and reduce reliability payments. Table 1-1 shows the representative future FRM requirements for Greater Southwest Connecticut, Greater Connecticut, and BOSTON. The actual required amounts will depend on operating conditions and requirements, which will change in accordance with the market rules. (Section 5)

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[19] The ISO's system operating procedures are available at http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

[20] For conducting some RSP studies, the BOSTON area (all capitalized) includes the city of Boston and northeast Massachusetts.

Table 1-1
Representative Future Operating-Reserve Requirements in Major New England Import Areas (MW)

Area/Improvement	Market Period[(a)]	Existing Amount of Fast-Start Resources (MW)[(b)]	Representative Future Locational Forward Reserve Market Requirements (MW)	
			Summer (June to Sept.)	Winter (Oct. to May)
Greater Southwest Connecticut		427 (summer)[(c)] 513 (winter)		
	2006		No locational FRM	550[(d)]
With SWCT Reliability Project Phase 1[(e)]	2007[(f)]		500–600	400–500
	2008		400–500	400–500
	2009		400–500	400–500
With SWCT Reliability Project Phase 2[(e)]	2010[(g)]		400–500	0
Greater Connecticut		662 (summer)[(h)] 831 (winter)		
	2006		No locational FRM	1,340[(d)]
	2007		1,200	1,200
	2008		1,200	1,200
	2009		1,200	1,200
	2010		1,200	1,200
BOSTON[(i)]		226 (summer) 335 (winter)		
	2006		No locational FRM	910[(d)]
With NSTAR 345 kV Transmission Reliability Project (Phase I)[(e)]	2007		900–1,300	0
With NSTAR 345 kV Transmission Reliability Project (Phase II)[(e)]	2008		300–700	0
	2009		50–400	0
	2010		150–500	0

(a) The market period is from June 1 through May 31 of the following year.

(b) These values are based on the resources' seasonal claimed-capability ratings (i.e., the maximum dependable load-carrying ability of a generating unit, excluding the capacity required for station use) and do not account for outage adjustments.

(c) This value does not include SWCT Emergency Capability Resources (see Section 4.1.1.1 and Section 5.2.1).

(d) These values are based on actual historical data. Data for future years are projected on the basis of assumed contingencies.

(e) The requirements are based on in-service dates projected by the transmission owners.

(f) The requirement is based on ISO operations resource adequacy process (see Section 4).

(g) The requirement is based on the ISO's resource adequacy process and assuming that operating reserve could be imported from outside the subarea.

(h) This value does not include SWCT Emergency Capability Resources but does include other resources in Greater Southwest Connecticut.

(i) The values for BOSTON are lower when load is shed in response to an N-2 transmission contingency (see Section 5.1), without consideration of the Mystic Units #8 and #9 common-mode failure.

1.1.4 Fuel Diversity

New England continues to face critical reliability risks and exposure to high wholesale electric energy costs because of the region's heavy dependence on generation fired by natural gas and oil. RSP06 has identified short-term, near-term, and long-term risks related to unforeseen disruptions in the fuel-supply chain and the lack of fuel diversity in the region. These risks can be those caused by hurricanes and other natural disasters, the lack of vigilant coordination between natural gas and electricity-sector operations, and supply-chain issues related to liquefied natural gas (LNG) imports and other supplies. (Section 6)

To mitigate these reliability risks, an RSP06 analysis of the system under high winter-load conditions shows that at least 1,400 MW of the 8,600 MW of gas-only units must be operational during periods of extreme cold during winter 2006/2007 to avoid the use of OP 4 actions. This amount grows to 2,800 MW by 2010/2011. In preparation for winter 2005/2006 operations, the ISO determined that about 3,000 MW of gas-fired generating units had firm gas pipeline transmission contracts through the five-year study period, which potentially can be held or sold on the basis of market conditions. Also, about 4,065 MW of generation holds air permits for dual-fuel operations and are candidates for dual-fuel conversion, although the units may require physical upgrades to burn liquid fuels.

To reduce exposure to reliability and price risks associated with the use of natural gas as a primary fuel, New England must evaluate and implement a combination of short- and long-term alternative solutions. A short-term action to improve reliability is to continue to enhance the coordination between electric power system and natural gas system operations. Increasing the number of firm contracts for natural gas supply and transportation can assist in addressing these concerns. Implementing additional conservation, energy-efficiency, and demand-response measures reduces the systemwide dependence on gas-fired generating capacity and improves the short-term and long-term reliability of the system. (Section 6 and Section 7)

New market incentives, such as those to be provided by the Forward Capacity Market, are designed to promote the availability of resources when most needed and improve the procurement of and contracting for fuel supplies and deliveries. These incentives should also increase the number of generators with dual-fuel generating capability. Environmental emissions regulations that require the use of low- or zero-emitting resources (see below), are likely to stimulate the development of renewable energy sources and other alternatives, such as new coal and nuclear technologies, to improve the fuel-diversity situation. Over the long term, improving the region's natural gas infrastructure, especially by building new LNG import terminals and by siting major intrastate, interstate, and international natural gas pipelines, can also mitigate the risks. (Section 6)

1.1.5 Impacts of Environmental Emission Regulations

Renewable Portfolio Standards (RPSs), which are in effect in Maine, Massachusetts, and Connecticut, and will go into effect in Rhode Island and Vermont, provide incentives for developing resources that emit no or low levels of pollutants. The implementation of the Regional Greenhouse Gas Initiative (RGGI), which Connecticut, Maine, New Hampshire, and Vermont have signed, and several federal regulations, could do the same. RSP06 studies show that meeting RGGI's carbon dioxide (CO_2) cap will require stronger regional efforts in conservation and energy efficiency, the addition of low- or zero-emitting baseload generation, or a combination of all measures by 2015. If Massachusetts and Rhode Island were to join RGGI, this need could advance to as early as 2010. The cost of RGGI allowances and offsets will likely be reflected in the wholesale electricity markets.[21] Any reduction in the availability of offsets or allowances would increase the likelihood of not meeting the RGGI cap. (Section 6.4.4 and Section 7)

1.1.6 Status of Transmission Upgrades

Much progress has been made toward completing transmission upgrades identified in previous RSP reports, ranging from substation improvements to new 345 kV circuits. Major new 345 kV projects under construction in 2006 include the following (Section 8):

- **Northeast Reliability Interconnection (NRI) Project—**includes a new 144-mile, 345 kV transmission line and supporting equipment to connect the Point Lepreau substation in New Brunswick, Canada, to the Orrington substation in northern Maine. This line, 84 miles of which are in Maine, is designed to increase transfer capability from New Brunswick to New England by 300 MW. The facility owners anticipate that the project will be in service by the end of 2007.
- **Northwest Vermont Reliability Project—**addresses the reliability needs in the northwestern area of Vermont. The project consists of a new 36-mile, 345 kV line, a new 28-mile, 115 kV line, additional phase-angle regulating transformers (PARs), two dynamic voltage-control devices, and static compensation. The Vermont Electric Power Company (VELCO) estimates the in-service dates for various components of this project range from late 2006 through 2007.
- **NSTAR 345 kV Transmission Reliability Project—**addresses the reliability needs in the Boston area and increases the Boston-import transfer capability by approximately 1,000 MW. This project includes the construction of a 345 kV substation in Stoughton and the installation of three new underground 345 kV lines: one 17-mile cable to K Street Substation, one 11-mile cable to Hyde Park Substation, and a second 17-mile cable to K Street Substation. NSTAR anticipates that the first portion of this project will be completed in 2006, and the final cable will be completed in 2007.
- **Southwest Connecticut Reliability Project—**addresses the reliability needs in Greater Southwest Connecticut, including the need to address operating constraints and impediments to interconnecting new generation. Phase 1 includes a 20-mile 345 kV circuit from Bethel to Norwalk, which Northeast Utilities plans to put in service in 2006. Phase 2 includes a 70-mile 345 kV circuit from Middletown to Norwalk, which transmission owners plan to put in service in 2009. Southwest Connecticut also requires a pair of new 115 kV lines from Norwalk to Glenbrook, planned to be in service in 2008.

The transmission plan also identifies additional improvements needed for simplifying the operation of the system, increasing overall system transfer capability, serving major load pockets, reducing dependence on generating units, and meeting transmission reliability requirements. In particular, the transmission plan identifies additional work required to fully develop a highly coordinated regional plan to meet the reliability requirements of southern and northern New England (NNE).

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[21] *Offsets* are reductions in greenhouse gas emissions in certain nonelectric sectors, including reductions in landfill gas (LFG) emissions and sulfur hexafluoride (SF_6) leaks, gas end-use efficiency savings, and afforestation.

Studies for southern New England will identify a series of projects that comprehensively address a number of significant long-term reliability issues affecting western Massachusetts in the Greater Springfield area, Rhode Island, and Connecticut. They will also integrate eastern and western New England and address the interdependence of the permissible levels of reliable power that flow into, through, and out of these areas. (Section 8)

Several areas of Maine and New Hampshire have serious reliability issues. The transmission improvement studies for northern New England will identify projects that will resolve these issues. These studies will also identify upgrades that will increase the transfer capabilities of the northern New England interfaces and simplify the operation of the system.

Other transmission improvements are required to serve load pockets or to meet basic transmission reliability criteria. The targeted areas include western Maine, Boston, the North Shore, southeastern Massachusetts, western Massachusetts, Springfield, Greater Connecticut, Middletown, Norwalk–Stamford, and southwestern Connecticut.

Not only are these transmission upgrades critical for maintaining bulk transmission system reliability and meeting the reliability standards of the North American Electric Reliability Council (NERC) and Northeast Power Coordinating Council (NPCC), they also can improve the economic performance of the system.[22] Over the next five to 25 years, all of these projects will enhance the region's ability to support a robust, competitive wholesale power market by reliably moving power from various internal and external sources to the region's load centers.

1.1.7 Cost-Impact Analyses

Cost-impact analyses of resource-expansion and demand-reduction scenarios show that increasing regional conservation and energy-efficiency measures and adding baseload units that have low marginal production costs can decrease wholesale electric energy costs and consumer costs, as well as production costs. The analysis estimated the cost impacts of each scenario using actual loads and offer data for 2005. The scenarios studied were as follows:

- Adding a 1,000 MW baseload unit with low marginal production costs, such as a nuclear unit, or a 1,000 MW low-emitting coal generator, assuming that only this type of coal technology could be sited in the region
- Increasing load by 5% over all hours
- Reducing load by 5% (on-peak conservation)
- Adding 500 MW of demand-response measures
- Increasing and decreasing natural gas prices by 10%

Assuming that an individual market participant paid the investment cost for 1,000 MW of new capacity with relatively low production costs and used its electric energy revenues to pay off these investments (i.e., the unit is economically efficient), purchasers in the wholesale market would save approximately $600 million in electric energy costs. Reducing the on-peak load by 5% would reduce consumer electric energy costs by $490 million, systemwide production costs by $360 million, and

[22] For more information on NERC, see at http://www.nerc.com. For more information on NPCC, see http://www.npcc.org.

total capacity costs by approximately $90 million.[23] A 10% increase in the price of natural gas would increase wholesale electricity prices by 6.8%, increasing consumer electric energy costs by $710 million and total production costs by $180 million. (Section 10)

A summary of projected transmission investments shows the potential impact of the transmission expansion plan on annual revenue requirements. The results show that the annual revenue requirement for all planned transmission facilities for which cost estimates are available is $585 million (assuming the annual revenue requirement was typically 18% of total estimated capital cost).[24] (Section 10)

1.1.8 Coordination with Neighboring Systems

Planning across interregional boundaries has successfully continued through the ISO's participation in NPCC and the implementation of the Northeastern ISO/RTO Planning Coordination Protocol.[25] Some of the benefits have included improved reliability and efficiency of generator interconnections close to regional boundaries. Studies of cross-border transmission security are examining loss-of-source contingencies in New England, including losing more than 1,200 MW on the Phase II high-voltage direct current (HVdc) interconnection with Québec. Other studies have been initiated to improve the sharing of capacity resources with neighboring systems, particularly the eastern Canadian provinces. The expansion of wind and hydro resources in eastern Canada may provide an opportunity for additional exports to New England beyond the 10-year timeframe. (Section 11)

1.1.9 ISO Initiatives

The ISO is continuing to pursue numerous activities to improve the adequacy, reliability, and security of the system. These include national initiatives mandated by the *Energy Policy Act of 2005* (EPAct) and interregional and systemwide planning efforts.[26] The ISO is fully participating in efforts by the North American Electric Reliability Council and the Federal Energy Regulatory Commission to establish the Electric Reliability Organization (ERO). It is also participating in the United States Department of Energy's (DOE's) process for designating National Interest Electric Transmission Corridors (NIETCs). Another initiative is to study ways for improving data acquisition and the ability of system operators to monitor the grid and take actions, including load shedding, at a substation feeder level. To promote energy efficiency across New England and encourage consumers and businesses to conserve electricity, the ISO has launched the *Take Charge New England*SM consumer-awareness campaign.[27] (Section 11)

1.2 Ongoing and Future Actions

To assure that all necessary improvements for providing a reliable, economic, and more robust electric power system in New England are implemented over the next 10 years, the following actions are needed on the basis of the results of RSP06 analyses (Section 12):

[23] This analysis assumes that the wholesale electric energy cost savings are fully passed on to consumers.

[24] The $585 million annual revenue requirement includes $119 million for local network service (LNS) assumed as part of Phase I of the Southwest Connecticut Reliability Project. It does not include miscellaneous projects for which cost estimates are not yet available.

[25] An *RTO* is a Regional Transmission Organization.

[26] *Energy Policy Act of 2005*, Pub. L. No.109-58, Title XII, Subtitle B, 119 Stat. 594 (2005) (amending the *Federal Power Act*).

[27] For more information on the *Take Charge New England*SM campaign, see http://www.takecharge-ne.org/.

- **Develop Resources—**Implement the Forward Capacity Market and the locational Forward Reserve Market. In the short term, add dual-fuel fast-start resources and demand response, especially in Greater Connecticut, to satisfy both the systemwide requirements and the load-pocket needs, make more efficient use of existing transmission and generation infrastructure, and save consumer capacity and congestion costs. Upon completion of the Southwest Connecticut Reliability Project, encourage the interconnection of resources in the northern and western parts of Southwest Connecticut. Over the long term, add economically efficient baseload generation with low marginal production costs, particularly units that do not burn natural gas or oil but have relatively low emissions. This would reduce the region's reliance on natural gas and decrease wholesale electric energy market prices.
- **Improve the Utilization of System Resources—**Link the wholesale and retail electricity markets to provide signals for encouraging more demand response and energy efficiency, which would improve the reliable operation of the system, decrease costs to consumers, and decrease generator air emissions. Promote conservation, energy efficiency, and demand response directly to residential, commercial, and industrial customers. Increasing the system load factor would make more efficient use of the electric power infrastructure.
- **Enhance Fuel Diversity—**Monitor the success of market mechanisms and environmental regulations to determine the most effective actions for diversifying the fuels used to generate electricity in New England. Provide incentives through the FCM and locational FRM for investing in dual-fuel fast-start resources in locally constrained areas. Improve the energy infrastructure and develop diverse energy technologies, such as renewable sources of energy, distributed generation, and new coal and nuclear technologies.
- **Improve the Reliability of Natural Gas Resources—**Develop operating procedures to improve the coordination of natural gas and electric power system operations. Assess the arrangements for firm procurement and transportation of natural gas and the operability of dual-fuel units. Ensure that at least 1,400 MW of generation that is currently fueled only by natural gas can be made available by winter 2006/2007 and that 2,800 MW is available by winter 2010/2011.
- **Develop Gas Supplies—**Identify the requirements for new natural gas supplies and expand the delivery capability of the natural gas system. Add LNG import and storage facilities to meet the increased demand for natural gas in New England and improve the availability of natural gas supply to gas-fired generation.
- **Complete Transmission Projects—**Work with transmission owners to complete the transmission improvements identified in RSP06 in a timely manner to improve the New England infrastructure and maintain power system reliability in the region over the next 10 years. Update the *Transmission Project Listing* as new improvements are identified and projects are completed or eliminated from the listing. Complete studies of northern and southern New England, especially studies of load pockets.
- **Improve the Monitoring and Control of the Grid—**Develop recommendations for improving data acquisition and the ability of system operators to respond, including the ability to disconnect customer load.
- **Improve Coordination with Neighboring Systems—**As the overall capacity situation continues to degrade throughout the Northeast, work closely with other control areas to

improve the coordination of planning efforts.[28] Over the long term, improve the ability to import power from the eastern Canadian provinces. Participate in national and regional activities, including those of DOE and NERC.

- **Comply with the ERO and Regional Reliability Organization Standards—**Meet specific mandatory reliability standards to maintain the reliable and secure operation of the bulk power system. For the ISO and its participants, comply with all required reliability standards through the NPCC Reliability Compliance and Enforcement Program.

These actions will involve the provision of market incentives, where appropriate, and proactive decision making and cooperation among the ISO, state officials, regional and environmental policy makers, transmission owners, other market participants, and other stakeholders.

[28] NPCC defines *control areas* as electric systems bounded by interconnection metering and communication systems that control generation to maintain an import-export schedule with other control areas and contribute to regulating the frequency of the interconnection. For further information, see http://www.npcc.org/default.asp. Also see http://www.nerc.com/.

Section 2
Introduction

ISO New England Inc. (ISO) is the not-for-profit Independent System Operator for the six New England states. The ISO's three main responsibilities are as follows:

- Reliable day-to-day operation of New England's bulk power generation and transmission system
- Oversight and administration of the region's wholesale electricity markets
- Management of a comprehensive regional bulk power system planning process

Created by the Federal Energy Regulatory Commission (FERC) in 1997, the ISO became a Regional Transmission Organization (RTO) in 2005. In this role, the ISO has assumed broader authority over the daily operation of the region's transmission system and greater independence to manage the region's electric power system and competitive wholesale electricity markets. The ISO works closely with state officials, policy makers, transmission owners, other participants in the marketplace, and other regional stakeholders to carry out its functions.

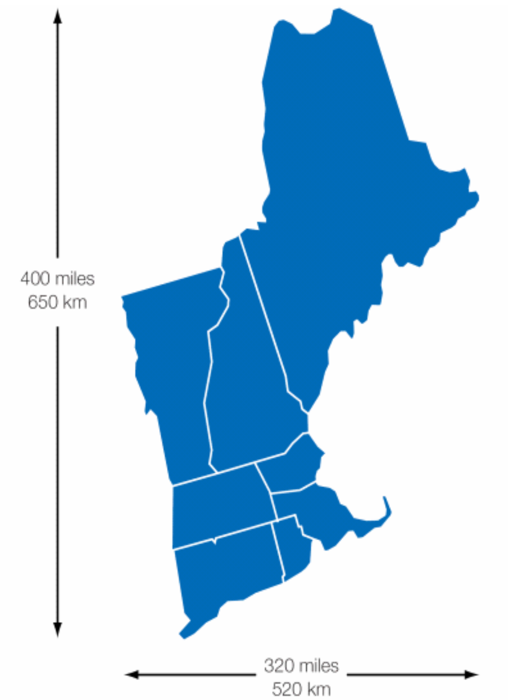
This section provides an overview of the bulk power system in New England and the role of the Regional System Plan (RSP) in ensuring the reliability and efficiency of the system. It also summarizes the key features of this year's RSP.

2.1 The New England Bulk Power System

New England's electric power grid and its central dispatch system were created by the New England Power Pool (NEPOOL) in 1971.[29] The New England system is fully integrated, using all regional generating resources to serve all regional load (i.e., the demand for electricity measured in megawatts, MW) independent of state boundaries. Most of the transmission lines are relatively short and networked as a grid. Therefore, the electrical performance in one part of the system affects all corners of the system. As shown in Figure 2-1, the New England regional electric system serves 14 million people living in a 68,000 square-mile area. More than 350 generating units produce electricity, representing approximately 31,000 MW of total generating capacity, most connected to approximately 8,000 miles of high-voltage transmission lines. Twelve tie lines interconnect New England with its neighbors, New York and New Brunswick and Québec, Canada. As of summer 2006, almost 500 MW of demand can be reduced as part of ISO's demand-response and price-response programs. Customers in these programs reduce load quickly to enhance system reliability or in response to price signals, respectively, in exchange for compensation based on wholesale electricity prices (see Section 5.2.1).[30]

[29] 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 serve as ISO stakeholders and market participants. For more information on NEPOOL participants, see http://www.iso-ne.com/committees/nepool_part/index.html#top.

[30] The 500 MW quantity does not include the demand response provided by other customer-based programs that are outside the ISO markets or control (i.e., *other demand resources,* ODRs).



- 6.5 million electricity customers; population 14 million
- 8,000+ miles of high-voltage transmission lines
- 350+ generators
- 12 interconnections with systems in New York and Canada
- 31,000+ megawatts of total supply (includes 500+ megawatts of demand response)
- Peak demand: approximately 28,130 megawatts on August 2, 2006 (after approximately 450 megawatts of load reduction from demand-response programs)
- 280+ participants in the marketplace
- $11.2 billion energy market

Figure 2-1: Key facts on New England's bulk electric power system and wholesale electricity market.

The ISO reached a new record summer-peak load of 28,130 MW on August 2, 2006, which was due to regionwide extreme temperatures and humidity. In accordance with ISO operating procedures, demand-response programs were activated to meet the load, which reduced the peak by approximately 450 MW. In the absence of these programs, the peak would have been 28,580 MW.[31]

2.2 RSP Purpose and Requirements

Many of the ISO's duties are regulated by its *Transmission, Markets, and Services Tariff*, a part of which is the *Open Access Transmission Tariff* (Transmission Tariff), approved by FERC.[32] As required by the tariff, the ISO works closely with the region's stakeholders through an open and transparent process. In particular, members of the Planning Advisory Committee (PAC) advise the ISO about the RSP scope of work and assumptions and comment on the preliminary study results and the final draft of the report.[33]

[31] All values related to the new summer-peak load are preliminary and will not be finalized until fall 2006. Also, the demand-response reductions are expected to increase because some demand-response assets have not yet been fully identified.

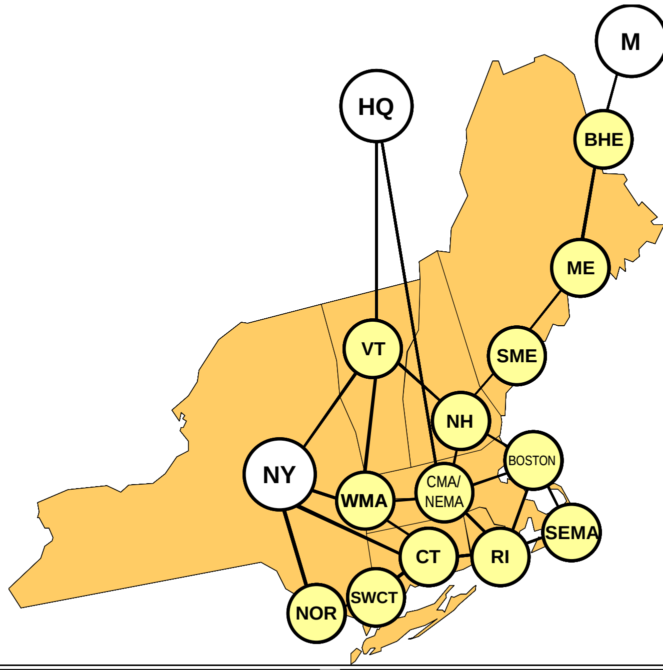
[32] FERC Electric Tariff No. 3, *ISO New England Inc. Transmission, Markets, and Services Tariff* (Part II, Section 48). See http://www.iso-ne.com/regulatory/tariff/index.html.

[33] Any stakeholder can designate a member to the PAC by providing written notice to the ISO. Additional information about the PAC is available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/index.html.

The purpose of the RSP is to provide an annual assessment of how to maintain the reliability of the New England bulk power system while promoting the operation of efficient wholesale electricity markets. To determine these needs, the ISO and its stakeholders analyze the system and its components as a whole, accounting for the many varied and complex interactions that occur among the components. The individual areas and parts of the system are also analyzed, because the performance of these components affects the performance of the system overall. During the planning process, the options for satisfying the defined needs are evaluated to determine which ones would be most effective, such as adding resources, reducing demand, upgrading the transmission system, or using a combination of solutions. Poorly designed system modifications can result in negligible benefits or even significant negative impacts.

Within New England, 13 subsets of the electric power system, called subareas, have been established to assist in modeling and planning electricity resources. These subareas reflect a simplified model of major transmission bottlenecks of the system, which are physical limitations of the flow of power that evolve over time because of the variety of system changes that occur. Figure 2-2 is a simplified model of the system that shows the ISO subareas and three external control areas.[34] The RSP06 analyses that use the subareas include the resource adequacy studies (see Section 4) and environmental emission studies (see Section 7). More detailed models are used for other types of analyses, including transmission planning studies (Section 8), and for the real-time operation of the system.

[34] A *control area* is an electric system bounded by interconnection metering and communication systems that can control generation to maintain an import-export schedule with other control areas and contribute to regulating the frequency of the interconnection.



Subarea Designation	Region or State	Subarea or Control Area Designation	Region or State
BHE	Northeastern Maine	**WMA**	Western Massachusetts
ME	Western and central Maine/ Saco Valley, New Hampshire	**SEMA**	Southeastern Massachusetts/ Newport, Rhode Island
SME	Southeastern Maine	**RI**	Rhode Island/bordering MA
NH	Northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine	**CT**	Northern and eastern Connecticut
VT	Vermont/southwestern New Hampshire	**SWCT**	Southwestern Connecticut
BOSTON	Greater Boston, including the North Shore	**NOR**	Norwalk/Stamford, Connecticut
CMA/NEMA	Central Massachusetts/ northeastern Massachusetts	**M, NY, and HQ**	Maritimes, New York, and Hydro-Québec external control areas

Figure 2-2: RSP06 geographic scope of the New England bulk electric power system.

Notes: Some RSP studies investigate conditions in "Greater Connecticut," which combines the NOR, SWCT, and CT Subareas. This area has similar boundaries to the State of Connecticut, but is slightly smaller because of electrical system limitations near the borders with western Massachusetts and Rhode Island. "Greater Southwest Connecticut" includes the southwest and western portions of Connecticut and comprises the NOR and SWCT Subareas.

In some of the ISO publications referenced in this report, the "M" designation for the Maritimes is labeled "NB," which includes the Maritime provinces of New Brunswick, Nova Scotia, and Prince Edward Island.

In addition to assessing the *amount* of resources that the overall system and individual subareas of the system need, the planning process assesses the *types* of resources that can satisfy these needs and any critical *time constraints* for addressing them. Thus, the RSP specifies the characteristics of the physical solutions that can meet the defined needs and includes information on market solutions to address them. Market participants can then use this information to develop the most efficient solutions, such as investments in demand-side projects, distributed generation, and merchant transmission.[35] If the market responses fall short of meeting these needs, or if additional transmission infrastructure is required to facilitate the market, the RSP must also identify a regulated transmission solution.

RSPs must account for the uncertainty in assumptions about the next 10 years considering changing demand, fuel prices, technologies, market rules, environmental requirements; other relevant events; and the physical conditions under which the system might be operating. Another requirement for developing RSPs is for the ISO to coordinate study efforts with surrounding RTOs and control areas and analyze information and data presented in neighboring plans. Each report must also provide the status of proposed and ongoing transmission upgrades and justify any newly proposed transmission improvements.

Regional System Plans must comply with North American Electric Reliability Council (NERC) and Northeast Power Coordinating Council (NPCC) criteria and standards and ISO planning and operating procedures.[36] The RSPs must also conform to transmission owner criteria, rules, standards, guides, and policies consistent with NERC, NPCC, and ISO criteria, standards, and procedures.

2.3 Features of RSP06

RSP06 provides information on the region's electricity needs from 2007 through 2015. Section 3 presents the load forecast, which is a key assumption for evaluating the reliability of the bulk power system under various conditions and determining whether and when improvements are needed. RSP06 uses a load forecast that accounts for a projected decrease in the system load factor over time. The forecast method is currently under review and may be replaced with a new model for future planning efforts.

Section 4 provides an estimate of the amount of additional resources the system will need to meet the resource adequacy requirements and indicates the areas that will most need this capacity. To characterize this need, the following types of data are presented:

- Systemwide loss-of-load expectation evaluation (LOLE) to assess the reliability of the bulk power system and adequacy of the system's generating resources to meet demand
- The minimum required amounts of capacity and the best locations for new resources
- The maximum useful amount of new resources that can be developed in export-constrained subareas while still providing resource adequacy benefits

Section 5 discusses desired operating characteristics for the region's generating resources, such as for shaving system peaks and enhancing reliability and security. These characteristics include having fast-start or demand-response capability.[37] The section also discusses how to meet identified system

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[35] *Demand-side* resources refers to the reduction of load by consumers, such as by using energy-efficient equipment, conserving energy in other ways, and using electricity generated on site (i.e., distributed generation), which reduces the overall system load (see Section 5.2.1). Demand-side resources also include demand-response measures. ODRs are demand-side resources outside the ISO's control.

[36] NERC and NPCC criteria and standards can be accessed at http://www.nerc.com/~filez/standards/Reliability_Standards.html and http://www.npcc.org/criteria.asp, http://www.iso-ne.com/rules_proceds/isone_plan/index.html, respectively. ISO operating procedures are posted at http://www.iso-ne.com/rules_proceds/operating/index.html.

[37] *Fast-start* capacity typically includes pumped storage and conventional hydro units, combustion turbines, load-response (i.e., load-reduction) program resources, and internal combustion units that can start up and be at full output in less than 30 minutes.

and load-pocket needs through the locational Forward Reserve Market (FRM), the alignment of the retail and wholesale electricity markets, and other market mechanisms.[38] The FRM is a forward-procurement market of the Ancillary Services Market Phase II (ASM II).[39]

Section 6 discusses the region's need to enhance fuel diversity. The section provides information on the region's fuel-supply mix, the risks related to the lack of fuel diversity, the results of natural gas supply studies, and regional short-and long-term actions to reduce the risks. It summarizes possible ISO initiatives, the status of new technologies for enhancing fuel diversity, and how regulations encourage or discourage fuel diversity. The relationship between fuel diversity and environmental emissions is also discussed, and market incentives for increasing fuel diversity are addressed. Section 7 discusses environmental requirements for resources, covering renewable resources and new constraints on power plant emissions.[40]

Section 8 summarizes the status of transmission investment, transmission system performance and development, and transmission projects, planned and underway, including those to reduce dependence on generating units in small load pockets. Section 9 presents the results of an assessment of the transmission-import needs for several major load pockets. This analysis identified possible minimum amounts of new resources or decreases in load that could defer the need for future transmission improvements. Guidance on the preferred locations for new interconnections is provided along with the status of the ISO Generator Interconnection Queue.

Section 10 presents a scenario analysis that shows the cost impacts of various demand-side changes and generation additions on electricity prices and capacity. Section 11 covers the status of national, interregional, and systemwide planning efforts and other initiatives for improving the reliability and security of the New England bulk power system, neighboring power systems, and the systems of the United States and North America as a whole. Section 12 includes the ISO's conclusions and recommendations about RSP06.

A list of acronyms and abbreviations used in RSP06 is included at the end of the report.

For more information on ISO system reliability for 2005, see the ISO's *2005 Annual Reliability Report* (ARR05).[41] For further details about New England's wholesale electricity markets, see the *2005 Annual Markets Report* (AMR05) and the *2006 Wholesale Markets Plan* (WMP06).[42]

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[38] *Load pockets* are areas of the system where the transmission capability is not adequate to import capacity from other parts of the system, and load must rely on local generation.

[39] The Ancillary Services Market project upgrades the ISO's market design and includes changes to reserve markets and the Regulation Market. For more information, see AMR05 at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html.

[40] *Renewable* sources of energy are those that are continually replenished and never exhausted, such as solar, hydro, wind, selected biomass, geothermal, ocean thermal, and tidal sources of power. Landfill gas (LFG) is also regarded as a renewable resource. Some states consider fuel cells to be renewable. Pumped hydro is not counted as a renewable resource since the electricity for pumping comes mostly from fossil fuel (i.e., nonrenewable) generators.

[41] The *2005 Annual Reliability Report* is available at http://www.iso-ne.com/pubs/arr/index.html.

[42] AMR05 can be accessed at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html. WMP06 can be accessed at http://www.iso-ne.com/pubs/whlsle_mkt_pln/index.html. The *2007 Wholesale Markets Plan* (WMP07) is scheduled for posting the same time as RSP06. See http://www.iso-ne.com/pubs/whlsle_mkt_pln/index.html.

Section 3
Annual Electric Energy and Peak-Load Growth

This section summarizes New England's regional, state, and subarea forecasts for the annual use of electric energy and peak loads. The section describes the economic and demographic factors accounted for in the forecasts and explains the forecast methodology.

3.1 Summary of New England's Annual and Peak Use of Electric Energy

The ISO load forecasts are estimates of the total annual and seasonal peak-hour amounts of electric energy used by the New England states. Each forecast cycle updates the data for the region's historical use of electric energy and peak loads by including resettlement adjustments, an additional year of data, and the most recent economic and demographic forecasts. These forecasts integrate the historical demand for each state, economic and weather data, and the impacts of utility-sponsored conservation and peak-load management programs on the forecasts.[43]

Table 3-1 summarizes the ISO's short-run electric energy and peak-load forecasts for 2006 and 2007. The net energy for load (NEL) shown in the table is the net generation output within an area, accounting for electric energy imports from other areas and subtracting electric energy exports to others. It also accounts for system losses but excludes the electric energy consumption required to operate pumped storage plants. The peak loads shown in the table have a 50% chance of being exceeded, expected to occur at a temperature of 90.4ºF (i.e., the 50/50 "reference" case). Peak loads with a 10% chance of being exceeded, expected to occur at a temperature of 94.2ºF, are considered the 90/10 "extreme" case (see below).

Table 3-1
Short-Run Forecast Summary of New England's Annual Use of Electric Energy and 50/50 Peak Loads

	2005[(a)]	2006	2007	% Change 2005–2006	% Change 2006–2007
Annual electric energy (1,000 MWh)[(b)] (NEL)	134,250	135,000	133,975	0.6	-0.8
Summer peak (MW)	26,545	27,025	27,355	1.8	1.2
Winter peak (MW)	22,600	22,550	22,810	-0.2	1.2

(a) Weather-normal actual loads are shown for 2005.

(b) "MWh" refers to megawatt hours.

The first two years of the forecast, 2006 and 2007, are affected by the large increases in the price of electricity that took place in 2005 (15%) and 2006 (20%) due to the increase in natural gas costs.[44] Electric energy growth slows to 0.6% in 2006 and declines by 0.8% in 2007. Summer-peak growth slows to 1.8% in 2006 and 1.2% in 2007, which is equivalent to a compound annual growth rate

[43] Two ISO Web sites, as follows, contain more detailed information on short-run and long-run forecast methodologies, models, and inputs; weather normalization; regional, state, and subarea annual electric energy and peak-load forecasts; high- and low-forecast bandwidths; and retail electricity prices: http://www.iso-ne.com/trans/celt/fsct_detail/index.html and http://www.iso-ne.com/trans/celt/report/index.html.

[44] From 2000 to 2005, the price of natural gas increased from about $5/million British thermal units (MMBtu) to $9.75/MMBtu, and the price for No. 6 fuel oil increased from $4/MMBtu to $6.70/MMBtu.

(CAGR) of 1.5% for 2005 through 2007.[45] Winter-peak growth declines by 0.2% in 2006 but increases by 1.2% in 2007 as electric energy growth picks up.

Table 3-2 summarizes the ISO's long-run annual electric energy and seasonal peak-load (50/50 and 90/10) forecasts for New England overall and for each state. The forecast assumes that as natural gas prices decline to and remain at their pre-Hurricane Katrina levels (see Section 6), the 2007 to 2015 electricity-price increases will be held to the rate of inflation.[46] Annual electric energy and winter-peak growth will be driven by other economic and demographic factors (see Section 3.2).

Table 3-2
Annual Electric Energy and Peak-Load Forecast Summary for New England and the States

State	Net Energy for Load (1,000 MWh)			Summer-Peak Loads (MW)					Winter-Peak Loads (MW)				
				50/50		90/10			50/50		90/10		
	2006	2015	CAGR	2006	2015	2006	2015	CAGR	2006/07	2015/16	2006/07	2015/16	CAGR
New England	**135,000**	**151,085**	**1.3**	**27,025**	**31,895**	**28,785**	**34,065**	**1.9**	**22,550**	**25,640**	**23,475**	**26,665**	**1.4**
Connecticut	34,745	39,350	1.4	7,250	8,535	7,730	9,120	1.9	5,955	6,760	6,220	7,060	1.4
Maine	12,100	14,095	1.7	2,020	2,420	2,115	2,540	2.1	1,975	2,250	2,025	2,310	1.5
Massachusetts	61,500	67,095	1.0	12,500	14,610	13,290	15,580	1.8	10,155	11,540	10,590	12,020	1.4
New Hampshire	11,725	13,840	1.9	2,365	2,985	2,575	3,270	2.7	2,015	2,385	2,105	2,490	1.9
Rhode Island	8,615	9,800	1.4	1,850	2,135	1,970	2,275	1.6	1,430	1,600	1,485	1,660	1.2
Vermont	6,320	6,910	1.0	1,045	1,215	1,105	1,290	1.7	1,025	1,110	1,055	1,140	0.9

The CAGR for electric energy is 1.3% for 2006 through 2015 and 1.4% for the winter peak. The summer-peak growth follows the annual growth in electric energy, but also includes a continuing decline in the summer-peak load factor (i.e., the ratio of the average hourly load during a year to the peak hourly load), as shown in Figure 3-1. The ISO attributes the declining load factors to an increase in the use of air conditioning, which has led to an increase in summer-peak loads relative to average load. This observation led the ISO to revise its methodology to account for the continued decline in the summer-peak load factor, which resulted in a 900 MW increase in the forecast by 2015, compared with the ISO forecasts conducted in 2005 (for 2014).[47] The summer-peak load CAGR is 1.9% per year for 2006 through 2015. This represents an increase of 500 MW to 600 MW per year.

State growth rates differ from the growth rate for New England overall owing to a variety of factors. For example, New Hampshire has the fastest growing economy in New England, and, in 2006,

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45 The CAGR is calculated as follows:

$$\text{Percent CAGR} = \left\{ \left[\left(\frac{\text{Peak in Final Year}}{\text{Peak in Initial Year}} \right)^{\left(\frac{1}{\text{Final Year} - \text{Initial Year}} \right)} - 1 \right] \times 100 \right\}$$

46 U.S. Energy Information Administration (EIA), *2006 Annual Energy Outlook*, DOE/EIA-0383, U.S. Department of Energy (DOE), Washington, DC, February 2006. See http://www.eia.doe.gov/oiaf/aeo/index.html.

47 The revision was based in the assumption that the historical increases in air-conditioning saturations will continue. Refer to the ISO's *2005 Regional System Plan* (RSP05) at http://www.iso-ne.com/trans/rsp/2005/index.html for additional information on the forecasts conducted in 2005.

Massachusetts had the largest increase in the price of electric energy, while Maine had one of the smallest.

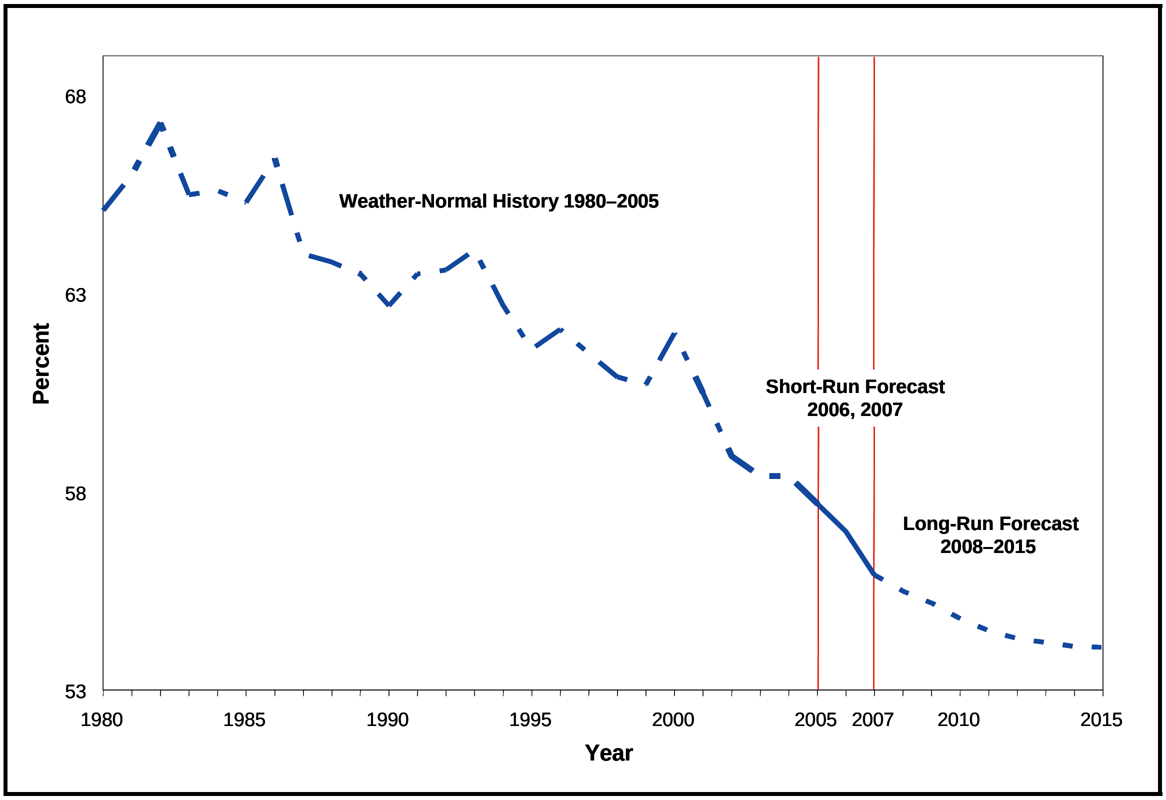

Figure 3-1: New England summer-peak load factor.

Note: The continuing decline of the long-run load factor follows the historical and short-run forecast downward trend and reflects increases in air-conditioning saturation.

3.2 Economic and Demographic Factors and Electric Energy Use

The ISO's New England and state forecasts for electric energy use are based on a total energy concept, which sums the total electric energy used residentially (40%), commercially (40%), and industrially (20%). The primary factors applied to determine electric energy use, which serve as proxies for overall economic and demographic conditions, are average income per household and the total number of households. Table 3-3 summarizes these and other indicators of the New England economy. The fall 2005 events in the Gulf Coast (see Section 6) did not have a significant impact on the New England economy, which continues to grow in the long run, although at lower rates than in the past.

Table 3-3
New England Economic and Demographic Forecast Summary

Factor	1980	2005	CAGR	2006	2015	CAGR
Summer peak (MW)	14,539	26,545	2.4	27,025	31,895	1.9
Net energy for load (1,000 MWh)	82,927	134,250	1.9	135,000	151,085	1.3
Population (thousands)	12,378	14,301	0.6	14,359	14,778	0.3
Households (thousands)	4,375	5,530	0.9	5,566	5,933	0.7
Employment (thousands)	5,539	6,948	0.9	7,064	7,606	0.8
Real income (millions, 1996$)	251,509	481,988	2.6	492,198	567,518	1.6
Real gross regional product (millions, 1996$)	268,941	640,221	3.5	658,412	838,298	2.7
Energy per household (MWh)	18.955	24.277	1.0	24.254	25.465	0.5
Real income per household (thousands) (1996 base year)	57.488	87.159	1.7	88.429	95.654	0.9

The long-run forecasts of annual and peak electric energy use for the New England states are explicitly adjusted to reflect reductions in the energy per household as a result of utility-sponsored conservation and load-management (C&LM) programs. New England utility companies provide these data annually, which are based on utility-initiated customer rebate and shared-savings programs for installing energy-efficient appliances, lighting, and electrical machinery and for subsidized weatherization programs. Table 3-4 shows the forecast reductions of annual electric energy use and peak loads, which lower New England's electric energy requirements by approximately 5%. Declines in electric energy and peak reductions may be a result of reduced funding for C&LM programs or the maturation of the effectiveness of programs already in place.

Table 3-4
Forecasts of Reductions in Annual Electric Energy Use and Peak Loads Due to Existing and Forecasted Conservation and Peak-Load Management Programs in New England(a)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Summer peak (MW)	1,603	1,656	1,690	1,696	1,655	1,564	1,494	1,504	1,513	1,522
Winter peak (MW)	1,478	1,502	1,504	1,494	1,460	1,396	1,265	1,269	1,277	1,274
Electric energy (1,000 MWh)	8,078	8,319	8,413	8,453	8,332	8,179	7,973	7,983	7,989	7,985

(a) The ISO does not independently verify the factors that could affect the reductions shown in the table, such as individual state actions affecting future funding for demand-side management programs.

3.3 Subarea Use of Electric Energy

Much of the RSP06 reliability analysis depends on forecasts for the annual and peak use of electric energy in the subareas, which are summarized in Table 3-5 and provide important market information to stakeholders.[48] Table 3-6 shows the peak-load forecasts for the New England states and Standard Market Design (SMD) load zones in relation to the RSP subareas.[49,50]

Table 3-5
Forecasts of RSP Subarea Annual Use of Electric Energy and Peak Loads, 2006 and 2015

Area	Net Energy for Load (1,000 MWh)			Summer-Peak Loads (MW)					Winter-Peak Loads (MW)				
				50/50 Load		90/10 Load			50/50 Load		90/10 Load		
	2006	2015	CAGR	2006	2015	2006	2015	CAGR	2006/07	2015/16	2006/07	2015/16	CAGR
NE	**135,000**	**151,085**	**1.3**	**27,025**	**31,895**	**28,785**	**34,065**	**1.9**	**22,550**	**25,640**	**23,475**	**26,665**	**1.4**
BHE	1,785	1,855	0.4	310	335	325	355	1.0	295	310	305	320	0.5
ME	6,425	7,445	1.7	1,045	1,280	1,095	1,345	2.3	1,085	1,255	1,110	1,285	1.6
SME	3,820	4,420	1.6	665	810	695	850	2.3	595	690	610	710	1.7
NH	9,710	11,825	2.2	1,910	2,510	2,075	2,740	3.1	1,670	2,000	1,745	2,085	2.0
VT	7,010	7,735	1.1	1,210	1,420	1,290	1,525	1.9	1,150	1,260	1,185	1,300	1.0
BOSTON	26,775	29,420	1.1	5,470	6,325	5,820	6,740	1.6	4,360	4,940	4,545	5,140	1.4
CMA/NEMA	8,505	9,320	1.0	1,750	2,020	1,860	2,160	1.7	1,435	1,610	1,495	1,680	1.3
WMA	10,940	11,970	1.0	2,075	2,380	2,205	2,540	1.6	1,845	2,080	1,920	2,160	1.3
SEMA	14,170	15,825	1.2	2,960	3,500	3,150	3,735	1.9	2,335	2,665	2,440	2,780	1.5
RI	11,455	12,715	1.2	2,465	2,870	2,630	3,060	1.7	1,895	2,140	1,970	2,230	1.4
CT	17,170	19,310	1.3	3,580	4,230	3,815	4,515	1.9	2,950	3,370	3,085	3,520	1.5
SWCT	11,345	12,810	1.4	2,340	2,770	2,500	2,960	1.9	1,960	2,235	2,045	2,330	1.5
NOR	5,905	6,440	1.0	1,260	1,455	1,345	1,555	1.6	990	1,090	1,035	1,140	1.1

[48] The loads are detailed on the ISO's Web site at http://www.iso-ne.com/trans/celt/fsct_detail/index.html.

[49] SMD is an energy-market structure that incorporates locational marginal pricing, multiple settlements in the Day-Ahead and Real-Time Energy Markets, and risk management tools to hedge against the impacts of higher differentials in locational marginal prices (LMPs) when transmission congestion occurs. LMPs are calculated and published prices for electricity at one of five types of locations or pricing nodes (pnodes) within the New England Control Area: external interfaces, load nodes, individual generator-unit nodes, load zones, and the Hub. The load zones are aggregations of pricing nodes within a specific area for which the ISO calculates and publishes day-ahead and real-time LMPs. Some SMD load zones have the same boundaries as some of the states, while other zones have boundaries related to the RSP subareas. Thus some subarea, load-zone, and state names are the same as well. For more information, see AMR05.

[50] For additional information, refer to the pricing node (pnode) table at http://www.iso-ne.com/stlmnts/stlmnt_mod_info/2006/. Also see AMR05 and Section 5.1.1).

Table 3-6
Loads for RSP Subareas, SMD Load Zones, and the New England States

RSP Subarea	SMD Load Zone	State	2006 Summer-Peak Load Forecast					
			50/50 Load			90/10 Load		
				Percent of			Percent of	
			MW	RSP Subarea	State Peak Load	MW	RSP Subarea	State Peak Load
BHE			**310**			**325**		
	ME	Maine	310	100	16.4	325	100	16.4
ME			**1,045**			**1,095**		
	ME	Maine	988	94.5	46.8	1,035	94.5	46.8
	NH	New Hampshire	57	5.5	2.1	60	5.5	2.1
SME			**665**			**695**		
	ME	Maine	665	100	33.9	695	100	33.9
NH			**1,910**			**2,075**		
	ME	Maine	50	2.6	2.8	54	2.6	2.8
	NH	New Hampshire	1,790	93.7	78.2	1,945	93.7	78.2
	VT	Vermont	70	3.6	6.9	76	3.6	6.9
VT			**1,210**			**1,290**		
	NH	New Hampshire	308	25.5	13	329	25.5	13
	VT	Vermont	902	74.5	86	961	74.5	86
BOSTON			**5,470**			**5,820**		
	NEMA/Boston	Massachusetts	5,391	98.6	43.1	5,736	98.6	43.1
	NH	New Hampshire	79	1.4	3.3	84	1.4	3.3
CMA/NEMA			**1,750**			**1,860**		
	West Central Massachusetts (WCMA)	Massachusetts	1,671	95.5	13.4	1,776	95.5	13.4
	NH	New Hampshire	79	4.5	3.4	84	4.5	3.4
WMA			**2,075**			**2,204**		
	CT	Connecticut	72	3.5	1	76	3.5	1
	WCMA	Massachusetts	1,929	92.9	15.4	2,049	92.9	15.4
	VT	Vermont	74	3.6	7.1	79	3.6	7.1
SEMA			**2,960**			**3,150**		
	SEMA	Massachusetts	2,811	95	22	2,992	95	22
	RI	Rhode Island	149	5	7.9	158	5	7.9
RI			**2,465**			**2,630**		
	SEMA	Massachusetts	759	30.8	6.1	810	30.8	6.1
	RI	Rhode Island	1,706	69.2	92.1	1,820	69.2	92.1
CT			**3,580**			**3,815**		
	CT	Connecticut	3,580	100	49.4	3,815	100	49.4
SWCT			**2,340**			**2,500**		
	CT	Connecticut	2,340	100	32.3	2,500	100	32.3
NOR			**1,260**			**1,345**		
	CT	Connecticut	1,260	100	17.4	1,345	100	17.4

3.4 Summary of Key Findings

RSP06 accounted for two changes that had an impact on the load forecasts. These changes and their effects on the forecasts are as follows:

- Large increases in the wholesale price of electric energy (15% in 2005 and 20% in 2006) affected the short-run forecast. The forecast shows New England summer-peak growth slowing to 1.8% in 2006 and 1.2% in 2007 due in part to these price increases.
- The methodology used to forecast load was changed to account for the continued decline in the summer-peak load factor. This caused the summer-peak forecast to increase by 900 MW by 2015 compared with the forecast conducted during 2005 (for 2014) using the constant load-factor methodology. New England's summer peak is forecast to grow at a CAGR of 1.9% in the long run, as electric energy prices stabilize and the summer-peak load factor continues to decline.

Other key findings of the forecasts are as follows:

- The net energy for load is expected to grow an average of 1.3% over the next 10 years.
- The forecast accounts for currently acknowledged conservation and peak-load management programs sponsored by regional utilities. The continuation of these existing utility-sponsored load-reduction programs is a key assumption underlying this forecast; without these programs, the peak load would be 1,500 MW to 1,600 MW higher.

Section 4
Resource Adequacy Analyses

Ensuring the adequacy of New England's electric power system requires planning at the systemwide level as well as the subarea level. For both systemwide and subarea planning, the ISO conducts probabilistic and deterministic resource adequacy analyses to estimate the amounts and locations of needed generation.[51]

For systemwide planning, the ISO uses a well-established probabilistic loss-of-load-expectation analysis. The LOLE analysis determines the amount of installed capacity (ICAP) the system needs to meet the NPCC and ISO resource adequacy planning criterion to not disconnect firm load more frequently than one day in 10 years.[52,53] The analysis examines the system under a range of forecasted loads, resource conditions, and possible tie-line benefits (i.e., the receipt of emergency capacity from within New England or neighboring regions). The results of these examinations show when potentially undesirable load interruptions might occur because of resource inadequacy and the associated need to implement operating procedures to maintain system reliability.

Using a deterministic approach, the ISO analyzes the systemwide operable capacity to estimate the net capacity that will be available under specific scenarios. The analysis identifies operable capacity margins (i.e., the amount of resources that must be operational to meet peak demand plus operating-reserve requirements) under assumed 50/50 and 90/10 peak-load conditions. The results of these examinations show either an expected system surplus or deficiency in meeting the requirements for the 50/50 and 90/10 loads. A negative margin indicates the potential need to implement ISO Operating Procedure No. 4, *Action during a Capacity Deficiency* (OP 4), to maintain reliable operations at the specified load level.

To determine the impacts that subarea load and resource changes could have on system LOLE, the ISO performs more detailed probabilistic analyses. The results of these analyses provide insights about which subareas contain sufficient resources to contribute to meeting systemwide resource adequacy, accounting for the projected capability of the transmission system interfaces.

Section 4 discusses the ISO's specific approach to conducting the RSP06 resource adequacy studies and summarizes the major findings of these studies. All of the analyses assumed that the overall system capacity will not change, either through unit additions or retirements.[54]

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[51] *Probabilistic analyses* reflect the use of statistical estimates of an event taking place. These analyses explicitly recognize that the inputs are uncertain; thus the outcome of a probabilistic analysis is a measure of the occurrence of the event expressed as a confidence level. *Deterministic analyses* are snapshots of assumed specific conditions that do not attempt to quantify the likelihood that these conditions will actually materialize. The outcome is the result of analyzing a set of conditions representing an acceptable state.

[52] *Installed capacity* is the megawatt capability of a generating unit, dispatchable load, external resource or transaction, or demand-side resource that qualifies as a participant in the ISO's ICAP Market per the market rules (see http://www.iso-ne.com/rules_proceds/index.html).

[53] Not meeting this criterion could result in a penalty for the New England Control Area, currently being developed by NPCC. For additional information, see http://www.npcc.org/criteria.asp.

[54] *Retirement* is the permanent removal from service of a facility, which cannot return to service without major refurbishment or relicensing.

4.1 New England Systemwide Analyses

For RSP06, the ISO conducted a systemwide LOLE analysis of Installed Capacity Requirements (ICR) from 2007 through 2015 to estimate the amount of resources New England will need to meet its resource adequacy planning criterion and when it needs these resources. To complement this analysis, the ISO conducted a systemwide operable capacity analysis to estimate the net capacity that will be available for 2007 to 2015 using 50/50 and 90/10 peak-load forecasts and assuming 1,800 MW of operating reserves and 2,100 MW of resource outages.

4.1.1 Systemwide Installed Capacity Requirement Analysis

This section describes the ISO's approach to conducting the RSP06 systemwide ICR analysis and summarizes the study results.

4.1.1.1 Approach

The model used for conducting the systemwide ICR calculations for New England accounts for the load and capacity relief obtainable from operating procedures, including the load-response programs and tie-line benefits assumed to be available from neighboring systems. The ISO assumed various levels of tie-line benefits for this analysis, recognizing the uncertainty of the future load and capacity conditions of neighboring systems and the amounts of tie-line benefits they might be able to provide to New England.

Determining the availability of tie-line benefits accounts for both the transmission-transfer capability of the tie lines and the capacity that may be available from neighboring systems when New England would need it. The ICR computation, known as the single-bus model, does not consider the transmission system constraints within New England.[55] The ICR analysis also modeled all known external firm purchases and sales, as reported in the ISO's *2005–2014 Forecast Report of Capacity, Energy, Loads, and Transmission* (*2005 CELT Report*).[56] The major assumptions used for the study were fully discussed with the PAC and are consistent with the *2006 CELT Report* and those used in the 2006/2007 ICR calculations.[57]

For the years that showed a capacity shortfall, the ISO determined the amount of generating resources that must be added to the system. Since the type of resources that will be added to the system is unknown at present, generic generator-expansion units were added to the system as needed as resource proxies.[58] These units served to keep the LOLE equal to or lower than the system criterion of not disconnecting firm load more frequently than one day in 10 years. The megawatts such units could provide served as an approximation of the possible amount of resources needed to meet this criterion. The actual amount of resources needed to comply with the LOLE criterion would vary depending on the type of resources actually installed to meet the need.

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[55] A *bus* is a point of interconnection to the system.

[56] The *2005* and *2006 CELT Reports* are available at http://www.iso-ne.com/trans/celt/report/index.html.

[57] The major ICR assumptions used, as presented to the PAC, are available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2006/jan232006/index.html and http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2006/feb152006/index.html.

[58] An expansion unit is a resource with an assumed size and set of outage characteristics that, when used in place of all resources in the system, does not materially change the resource adequacy (LOLE) of the system.

The ICR analyses simulated several levels of tie-line benefits: 0 MW, 1,000 MW, 2,000 MW (the current FERC-approved level), and 3,000 MW. In this ICR analysis, the Hydro-Québec Installed Capacity Credit (HQICC) was assumed to be zero to consistently capture the impact of various amounts of tie-line benefits on future resource needs.[59]

Southwest Connecticut Emergency Capability Resources, which can operate only under OP 4 conditions, were modeled as OP 4 resources consistent with current operating practice (see Section 5.2).[60] The studies assumed that these resources would be operational through the study period that ends in 2015.

4.1.1.2 Findings

Figure 4-1 and Table 4-1 summarize the results of the systemwide analysis of the Installed Capacity Requirement. The findings show that New England will need new resources in the 2007 to 2011 timeframe. The varying tie-line benefit assumptions result in various amounts of capacity that will be needed to meet New England's resource adequacy planning criterion.

[59] As defined in the ISO's tariff, the HQICC is a monthly value that reflects the annual installed capacity benefits of the HQ Interconnection, as determined by the ISO using a standard methodology on file with FERC.

[60] Southwest Connecticut Emergency Capability Resources are obtained through the Southwest Connecticut Gap Request for Proposal (Gap RFP). The RFP, issued by the ISO on December 1, 2003, is for special payments of up to 300 MW of fast-start generation, demand response, and load-management resources available on nonholiday weekdays from 7:00 a.m. to 6:00 p.m. For additional information, see http://www.iso-ne.com/genrtion_resrcs/rfps/SWCT_GAP_RFP_2003-12-01.pdf.

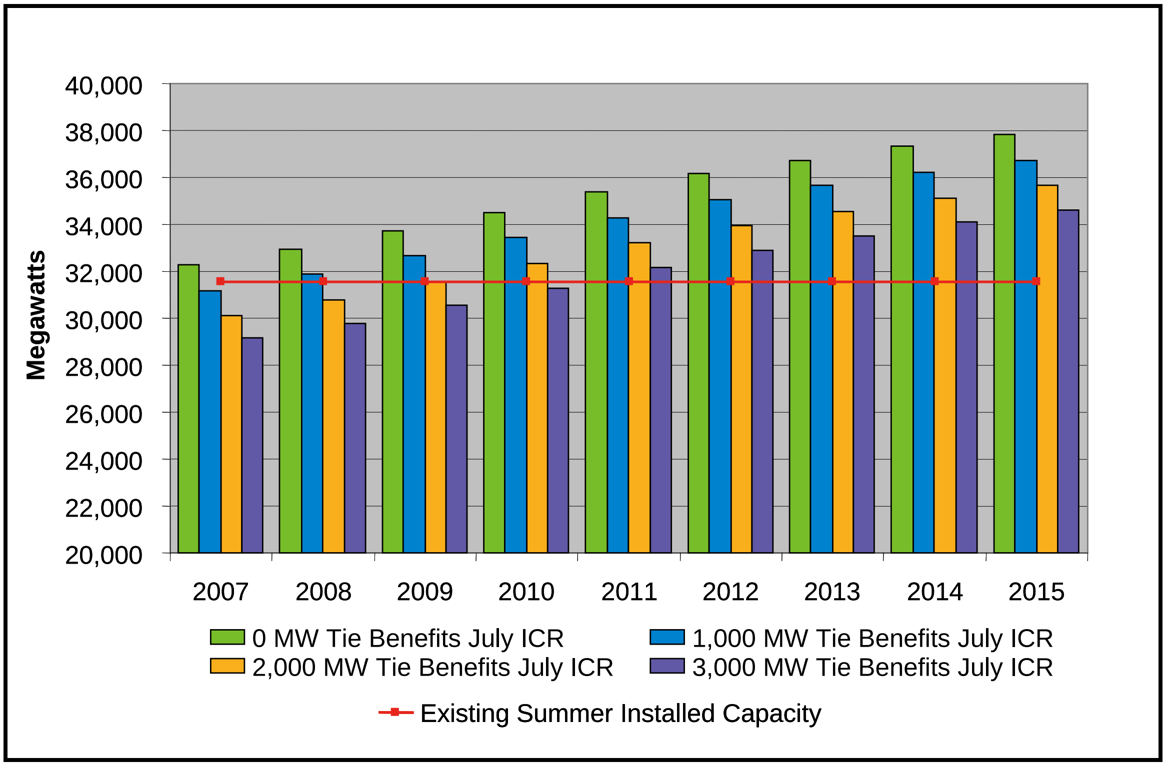

Figure 4-1: Projections of New England installed capacity requirements assuming different amounts of tie-line benefits (MW).

Notes: The bars represent the July ICR for each power year under the four tie-line benefit assumptions as noted in the legend. (A *power year* runs from June 1 through May 31 of the following year.) The horizontal line across the bars represents the total capacity eligible to claim the installed capacity credit assumed in the calculation. Expansion units are needed when the system does not meet the one-day-in-10-year LOLE criterion. For example, for 2009, with 2,000 MW of tie-line benefits, the system requires 75 MW of firm capacity, for which the model added a typical 173 MW unit.

Table 4-1
Cumulative Capacity Needed in New England

Year	0 MW Tie-Line Benefits	1,000 MW Tie-Line Benefits	2,000 MW Tie-Line Benefits	3,000 MW Tie-Line Benefits
2007	863	-	-	-
2008	1,553	518	-	-
2009	2,415	1,208	173	-
2010	3,105	2,070	1,035	-
2011	3,968	2,933	1,725	690
2012	4,658	3,623	2,588	1,553
2013	5,348	4,313	3,105	2,070
2014	5,865	4,830	3,795	2,760
2015	6,383	5,348	4,313	3,105

If no tie-line benefits were assumed to meet the resource planning reliability criterion, New England would need approximately 860 MW of additional capacity or demand-response resources as early as 2007. This need would increase annually to a total of approximately 6,400 MW by 2015. The additional amount of needed resources would be exacerbated by unit retirements, higher load growth, lower unit availability, transmission constraints, and a variety of other factors.

Assuming 1,000 MW of tie-line benefits, New England would need approximately 500 MW of additional capacity or demand-response resources starting in 2008, increasing annually to approximately 5,350 MW by 2015. Using 2,000 MW of tie-line benefits, New England would need additional capacity or demand-response resources, starting with one expansion unit (of approximately 170 MW), before summer 2009 to meet the one-day-in-10-year LOLE criterion. Additional resources would be needed every year after 2009 to meet the criterion; by 2015, a total of 4,300 MW of additional resources would be needed assuming no existing resources were to retire. If 3,000 MW of tie-line benefits were assumed, New England would need approximately 700 MW of additional capacity or demand-response resources starting in 2011, increasing annually to approximately 3,100 MW by 2015.

In summary, the ICR analysis shows that for the range of tie-line benefits examined, New England would need a minimum of 3,100 MW of additional resources by 2015 if it could rely on 3,000 MW of tie-line benefits from neighboring systems. In the more extreme case of no tie-line benefits, New England would need a maximum of 6,400 MW of new resources by the same year. Further details on the LOLE analysis methodology, assumptions, and results can be found in the material presented to the PAC.[61]

Figure 4-2 shows how often OP 4 actions would need to be implemented during the planning period to meet expected peak loads and operating reserves associated with the systemwide ICR using the same assumptions as described above for tie-line benefits. The frequency of calling on OP 4 actions is a function of the amount of load and capacity relief assumed to be provided by ICR resources. Having fewer ICAP resources available means these resources would more often be insufficient to meet the load plus operating reserve requirements. When ICAP resources are insufficient, OP 4 actions are called on to meet the need. The higher the amount of OP 4 resources used to meet the ICR, the lower the amount of ICAP resources needed to meet the ICR. This relationship applies to all OP 4 resources, which includes tie-line benefits.

[61] This material is available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2006/feb152006/index.html.

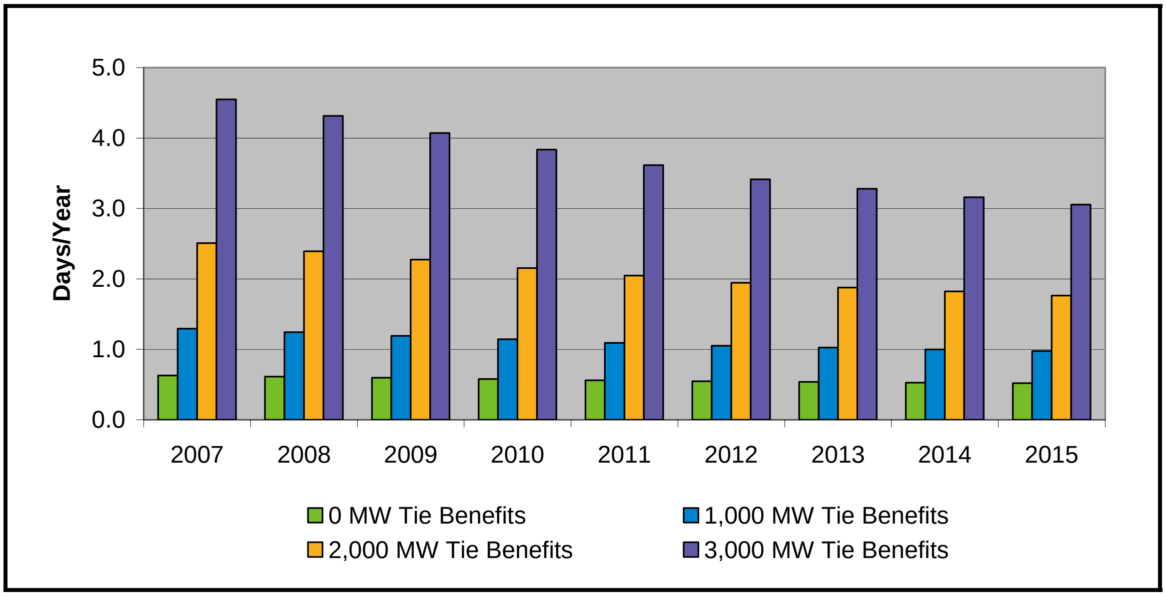

Figure 4-2: Expected days per year of needing to implement OP 4 actions under various assumed tie-line benefits.

As shown, OP 4 actions would occur approximately once per year, if no tie-line benefits were assumed as an OP 4 resource (i.e., the 0 MW tie-line benefit) to meet the one-day-in-10-year LOLE criterion. The need to call on OP 4 actions would increase to approximately one to two times per year if 1,000 MW of tie-line benefits were assumed, about two to three times per year if 2,000 MW of tie-line benefits were assumed, and three to five times per year if 3,000 MW of tie-line benefits were assumed.

Assuming 2,000 MW of tie-line benefits and no additional resources added to the system, the implementation of OP 4 actions would be expected to grow from approximately three times per year to approximately 12 times per year by 2015. The possibility of having to disconnect firm customer load would therefore increase depending on the actual amount of load relief obtainable through OP 4 actions.

4.1.2 Systemwide Operable Capacity Analysis

For RSP06, the ISO conducted a systemwide operable capacity analysis for 2007 to 2015. This section discusses the methodology used to conduct this analysis and summarizes its results.

4.1.2.1 Approach

The operable capacity analysis used 50/50 and 90/10 peak-load forecasts and assumed 1,800 MW of operating reserves and 2,100 MW of resource outages on the basis of historical observations. The results do not reflect generating-unit additions, retirements, or deactivations that could occur during the planning period.[62]

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[62] *Deactivation* is the "mothballing" of a facility, such that with some minor reconditioning, it could be brought back into service in a relatively short time period.

4.1.2.2 Findings

Figure 4-3 and Table 4-2 show the results of the systemwide operable capacity analysis. The results show that if the loads associated with the 50/50 forecast were to occur, New England could experience a negative operable capacity margin of approximately 400 MW as early as summer 2008 and would need to rely on OP 4 actions for load and capacity relief. This negative operable capacity margin would grow to 4,400 MW by summer 2015, if no additional resources were added to the system.

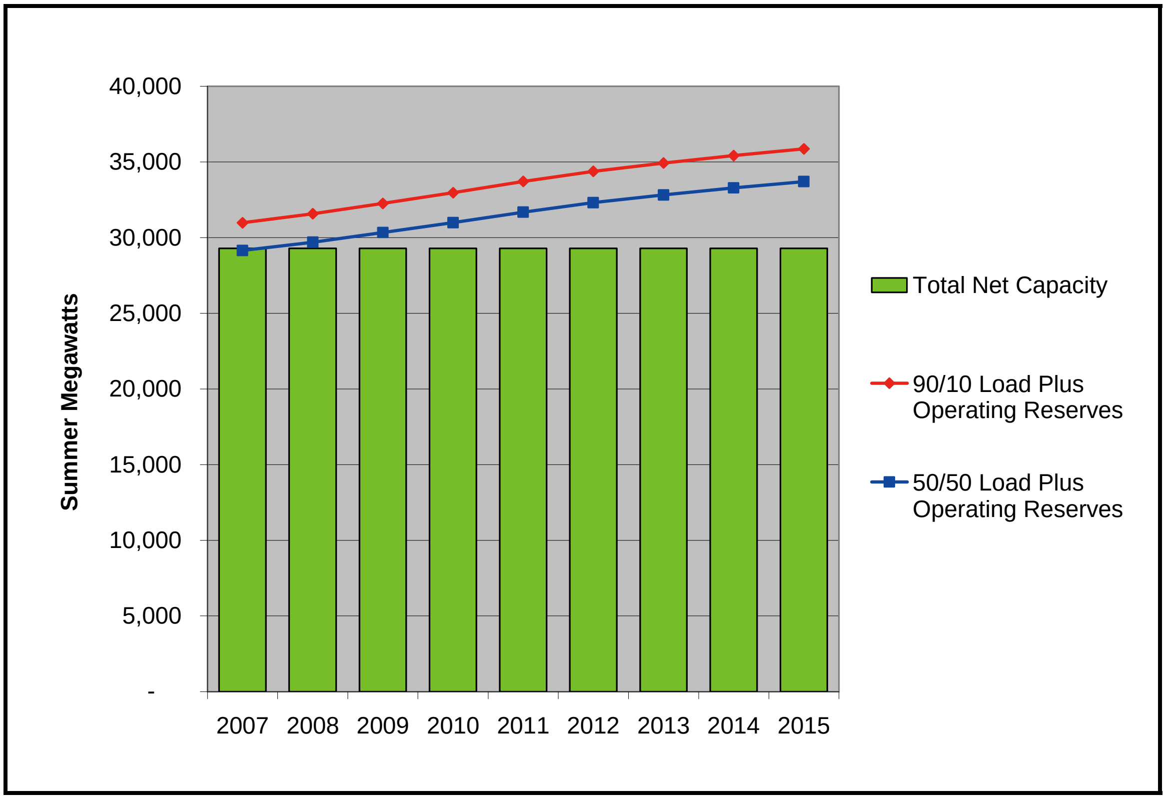

Figure 4-3: Projected New England capacity situation, summer 2007–2015, using 50/50 and 90/10 loads (MW).

Table 4-2
Projected New England Capacity, Summer 2007–2015, Using 50/50 Loads (MW)

Capacity Situation (Summer MW)	2007	2008	2009	2010	2011	2012	2013	2014	2015
Load (50/50 forecast)	27,355	27,900	28,540	29,185	29,885	30,515	31,020	31,480	31,895
Operating reserves	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800
Total requirement	29,155	29,700	30,340	30,985	31,685	32,315	32,820	33,280	33,695
Capacity	30,931	30,931	30,931	30,931	30,931	30,931	30,931	30,931	30,931
Net purchases/sales	463	463	463	463	463	463	463	463	463
Assumed unavailable capacity	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)
Total net capacity	29,294	29,294	29,294	29,294	29,294	29,294	29,294	29,294	29,294
Operable capacity margin[(a)]	**139**	**(406)**	**(1,046)**	**(1,691)**	**(2,391)**	**(3,021)**	**(3,526)**	**(3,986)**	**(4,401)**

(a) "Operable capacity margin" equals "total net capacity" minus "total requirement."

Similarly, Figure 4-3 and Table 4-3 show that New England could experience a negative operable capacity margin of approximately 1,700 MW as early as summer 2007, if the 90/10 peak loads occurred, the assumed amount of generation outages materialized, and no new resources were added. Thus, starting in 2007, New England would need to rely on load and capacity relief from OP 4 actions to meet the 90/10 peak loads. Without the addition of new resources, this negative operable capacity margin will get progressively larger and reach approximately 6,600 MW by 2015 as load grows.

Table 4-3
Projected New England Capacity Situation, Summer 2007–2015, Using 90/10 Loads (MW)

Capacity Situation (Summer MW)	2007	2008	2009	2010	2011	2012	2013	2014	2015
Load (90/10 forecast)	29,180	29,775	30,465	31,160	31,910	32,580	33,125	33,620	34,065
Operating reserves	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800	1,800
Total requirement	30,980	31,575	32,265	32,960	33,710	34,380	34,925	35,420	35,865
Capacity	30,931	30,931	30,931	30,931	30,931	30,931	30,931	30,931	30,931
Net purchases/sales	463	463	463	463	463	463	463	463	463
Assumed unavailable capacity	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)	(2,100)
Total net capacity	29,294	29,294	29,294	29,294	29,294	29,294	29,294	29,294	29,294
Operable capacity margin[(a)]	**(1,686)**	**(2,281)**	**(2,971)**	**(3,666)**	**(4,416)**	**(5,086)**	**(5,631)**	**(6,126)**	**(6,571)**

(a) "Operable capacity margin" equals "total net capacity" minus "total requirement."

Adding new resources to the system, consistent with the requirements for installed capacity, would decrease the region's dependence on load and capacity relief from OP 4 actions. For example, adding 4,300 MW of resources in 2015 would greatly reduce the need to call on OP 4 actions.

4.1.3 Observations

Failing to provide new resources in the 2007 to 2011 timeframe would result in New England's not meeting its resource adequacy criterion and increasing the region's exposure to OP 4 actions. The timing and amount of resources needed depends on the assumed tie-line benefits.

The probabilistic ICR analysis shows (in Table 4-1) that New England will need approximately 170 MW of additional resources before summer 2009 to meet the New England resource planning reliability criterion to avoid disconnecting firm load more frequently than one day in 10 years. These results assumed the tie-line benefits were at the current level of 2,000 MW. The amount of total new resources needed would increase to approximately 4,300 MW by 2015.

Additional resources will be required in New England sooner than 2009 under several circumstances. One such situation would be if tie-line benefits assumed to be available to meet the LOLE criterion were reduced, either physically or as a result of a regional decision to change the dependence on outside emergency assistance to meet the criterion. If additional tie-line benefits were assumed to be available, the need for additional resources would be delayed until 2011. The results of the systemwide analysis show the specific years and magnitude of resource needs associated with the tie-line benefit scenarios ranging from 0 MW to 3,000 MW. In summary, 3,100 MW to 6,400 MW will be needed by 2015, depending on the amount of tie-line benefits New England is willing to rely on from the neighboring control areas. It is expected, but not quantified, that when tie-line benefits are needed, they will often be obtained as relatively high-priced short-term electric energy purchases in the wholesale electricity markets.

On the basis of the deterministic systemwide operable capacity analysis, New England will need approximately 1,700 MW of load and capacity relief from OP 4 actions to meet the projected 90/10 loads in 2007. The need for capacity relief from OP 4 actions would grow to approximately 6,600 MW by 2015 because this analysis assumed that no resources will be added to the system. However, the ISO expects that adequate installed capacity will be available as a result of the implementation of the Forward Capacity Market (FCM) and the guaranteed capacity payments made during the transition period of this market.[63]

4.2 Analysis of Subarea Resource Adequacy Needs

For RSP06, the ISO analyzed the resource adequacy of subareas using a probabilistic approach. The LOLE calculation in this analysis reflects a simplified modeling of the major transmission limitations in the New England system. The results show the number of days that disconnecting firm load might be expected to occur in subareas, as measured by a change in the systemwide LOLE. An LOLE of more than 0.1 day per year (one day in 10 years) is an unacceptable level of risk, on the basis of the

[63] An auction process is currently being developed for the FCM to provide sufficient capacity three years in advance to meet the projected ICR. FERC approved the FCM Settlement Agreement in June 2006 [Devon Power LLC, *Order Accepting Proposed Settlement Agreement,* Docket Nos. ER03-563-030 and ER03-563-055, 115 FERC ¶61,340 (June 16, 2006).] See AMR05 (Section 3.3) and WMP07 for additional information on this market.

NPCC criterion, because it indicates the likelihood of a subarea having insufficient resource capacity, transmission capability, or both.

4.2.1 Approach

To gauge the ability of constrained load pockets to access capacity from other subareas and to identify the impacts that transmission constraints could have on the system LOLE, the analysis modeled the load, resources, and internal transmission-interface limits of the region's 13 subareas. The models considered long-term generator forced outages, unit retirements, or higher-than-forecasted load-growth conditions, as well as internal transmission-interface limits of the subareas to identify the subareas at greatest risk of lacking adequate resources or transmission capability.[64] The load in individual subareas was then increased or decreased to determine the impact on the systemwide LOLE.[65]

Since the single-bus model of the systemwide ICR analysis does not incorporate transmission limits, the results of the ICR analyses show only the risks of not having enough resources to serve the forecast load. In contrast, the results of the subarea resource adequacy analyses that model transmission constraints reveal where transmission upgrades may be able to reduce the LOLE or the need for new resources or where resources should be installed to maximize the use of the existing transmission configuration. They may also show higher LOLE values (i.e., the need to disconnect firm load on more days than the criterion allows), compared with the results of the single-bus model. This is because a transmission-interface transfer capability incorporated into the model may show that capacity is prevented from flowing from areas of surplus to areas of need.

Table 3-6 (see Section 3.3) presents the 2006 peak loads for RSP subareas used in this analysis. Table 4-4 tabulates the current generating capacity by subarea. The analysis assumed no new resources will be added, even those that may be installed to meet various states' Renewable Portfolio Standards (RPSs) (see Section 7.1). However, this analysis also assumed 2,000 MW of tie-line benefits (1,200 MW from Hydro-Québec, 600 MW from New York, and 200 MW from New Brunswick).

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[64] A *forced outage* is when a unit or a portion of a unit is out of service because of the discovery of a problem that must be repaired as soon as crews, equipment, and/or corrective dispatch actions can be activated to allow the work to be performed.

[65] Detailed results of subarea resource adequacy needs are documented in the ISO's report, *2006 Resource Adequacy Analysis*, posted at the ISO password-protected site, http://www.iso-ne.com/trans/sys_studies/rsp_docs/rpts/2006/final_rsp06_resource_adequacy.pdf. Contact ISO Customer Service at (413) 540-4220 for additional information.

Table 4-4
RSP06 Generating Capacity by Subarea, SMD Load Zone, and State

RSP Subarea	SMD Load Zone	State	Summer (MW) [a] Capacity Rating	Summer Percent of RSP Subarea	Summer Percent of State	Winter (MW) [a] Capacity Rating	Winter Percent of RSP Subarea	Winter Percent of State
BHE			**873**			**951**		
	ME	Maine	873	100	26.5	951	100	27
ME			**926**			**1,005**		
	ME	Maine	926	100	28.1	1,005	100	28.5
SME			**1,501**			**1,565**		
	ME	Maine	1,501	100	45.5	1,565	100	44.4
NH			**4,070**			**4,213**		
	NH	New Hampshire	4,010	98.5	99.9	4,152	98.6	99.9
	NH	Vermont	3	0.1	0.3	3	0.1	0.2
	VT	Vermont	41	1	4.2	41	1	4
	WCMA	Massachusetts	17	0.4	0.1	17	0.4	0.1
VT			**864**			**921**		
	NH	New Hampshire	2	0.3	0.1	2	0.3	0.1
	NH	Vermont	90	10.4	9.2	90	9.8	8.7
	VT	Vermont	772	89.3	79.4	829	90	80.6
BOSTON			**3,587**			**4,039**		
	SEMA	Massachusetts	0	0	0	0	0	0
	WCMA	Massachusetts	9	0.3	0.1	15	0.4	0.1
	NEMA/Boston	Massachusetts	3,578	99.7	26.8	4,024	99.6	27.5
CMA/NEMA			**119**			**121**		
	SEMA	Massachusetts	0	0	0	0	0	0
	WCMA	Massachusetts	119	100	0.9	121	100	0.8
WMA			**3,703**			**3,986**		
	WCMA	Massachusetts	3,636	98.2	27.3	3,920	98.3	26.8
	WCMA	Vermont	67	1.8	6.9	66	1.7	6.4
SEMA			**3,345**			**3,622**		
	RI	Rhode Island	245	7.3	13.5	279	7.7	13.5
	SEMA	Massachusetts	3,100	92.7	23.2	3,343	92.3	22.9
RI			**5,144**			**5,769**		
	RI	Connecticut	700	13.6	9.3	809	14	10.2
	RI	Rhode Island	1,569	30.5	86.5	1,792	31.1	86.5
	SEMA	Massachusetts	2,875	55.9	21.6	3,168	54.9	21.7
CT			**4,414**			**4,524**		
	Connecticut	Connecticut	4,413	100	58.9	4,524	100	56.8
SWCT			**1,987**			**2,209**		
	Connecticut	Connecticut	1,987	100	26.5	2,209	100	27.7
NOR			**396**			**422**		
	Connecticut	Connecticut	396	100	5.3	**422**	100	5.3

(a) Sum may not add because of rounding.

Table 4-5 shows the transmission-interface limits used in this analysis. These limits are a critical part of RSP analyses and represent potentially limiting areas of the New England transmission system that may become constrained under a variety of system conditions. The values in the table are based on ISO studies that reflect recent and future system improvements and changes in system configuration, coordinated voltage dispatch, and operating experience. The limits are reviewed and updated at least annually; a uniform procedure for developing these limits has been reviewed through the stakeholder process. Detailed documentation of supporting studies is available to stakeholders according to the ISO's *Information Policy*.[66]

This analysis modeled the interface limits between RSP subareas as constant or static for each transmission system configuration considered. However, transmission-interface operating limits change constantly in the real-time operating environment. The most limiting transmission facility and critical contingency, which limits the interface transfer, can change depending on unit dispatch, load level, and load distribution. The interface limits used in this analysis reflect the most restrictive of the thermal, voltage, and stability limits under reasonable assumptions for stressed system conditions suitable for resource adequacy studies.

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[66] For more information on the ISO's *Information Policy*, see http://www.iso-ne.com/regulatory/tariff/attach_d/attach_d-iso_info_policy%20_effective_05-12-06.pdf.

Table 4-5
Transmission-Interface Limits Used in Studies Modeling Subareas

Interfaces	Interface Limit Assumptions for Studies[a] (MW)	Basis for Interface Limits: Explanation	Basis for Interface Limits: Relevant Study or Descriptive information
New Brunswick–New England	2006: 700 2007: 1,000[b]	Stability	New Brunswick–New England Tie Study
Maine–New Hampshire	2006: 1,475 2008: 1,600 2009: 1,575 2011: 1,550 2013: 1,525 2015: 1,500	Steady state (summer)	ISO New England Studies: Determination of 2006–2015 Transfer Limits
Orrington South Export	2007: 1,200[a]	Thermal (summer)	Northeast Reliability Interconnection Project
Surowiec South	2007: 1,250[a]		2000 Maine Operating Study Y-138
North–South[c]	2,700	Thermal (summer)	Typical operating study result
HQ–NE (Highgate)	200	High-voltage direct current (HVdc) equipment design limit and voltage	N/A
HQ–NE (Phase II)	1,200	External voltage constraints that occur in the PJM and New York ISO (NYISO) areas[d]	Historical operating practice
BOSTON Import	2007: 4,600[e] 2008: 4,900[e]	Thermal (summer)	ISO New England Studies: Determination of 2006–2015 Transfer Limits
SEMA Export	No limit	Stability	SEMA/RI Export Enhancement Feasibility Study
(1) SEMA / RI Export **(2) East–West[f]**	(1) 3,000 (2) 2,400	Simultaneous stability/thermal	SEMA/RI Export Enhancement Feasibility Study TBD
(3) Connecticut Import	(3) 2,500	Steady state (summer)	ISO New England Studies: Determination of 2006–2015 Transfer Limits
Southwest Connecticut Import[a]	2007: 2,350[g] 2010: 3,650[h]	Steady state (summer)	ISO New England Studies: Determination of 2006–2015 Transfer Limits
Norwalk/Stamford	2007: 1,300[g] 2010: 1,650[h]	Thermal (summer)	ISO New England Studies
New York–New England (without Cross-Sound Cable)	Summer (in/out) 1,175/1,150 Winter (in/out) 1,600/990	Steady state	NYISO Winter 2005/2006 Operating Study
Cross-Sound Cable	346 in/330 out Both directions	HVdc equipment design limit	Cross-Sound Cable System Impact Study

(a) The procedure and studies supporting the static transmission-interface limits are subject to review by the NEPOOL Reliability Committee.

(b) The value reflects the completion of the Northeast Reliability Interconnection (NRI) Project by December 2007 (see Section 8.3).

(c) The North–South interface separates the subareas located in ME, NH, and VT from those located in CT, MA, and RI (see Figure 4-4, below).

(d) PJM Interconnection LLC is the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and the District of Columbia.

(e) The values reflect the completion of Phase I of the NSTAR 345 kV Transmission Reliability Project by 2006 and Phase II by December 2007 (see Section 8.3).

(f) The East–West interface separates eastern New England from western New England (see Figure 4-4, below).

(g) The value reflects the completion of Phase 1 of the Southwest Connecticut Reliability Project by June 2007 (see Section 8.3).

(h) The value reflects the completion of Phase 2 of the Southwest Connecticut Reliability Project by December 2009 (see Section 8.3).

Figure 4-4 illustrates the configuration of the New England system and the major transmission interfaces with the neighboring systems modeled in this analysis. In the model, the total generation at Mystic Units #8 and #9 (in the BOSTON Subarea) and the import from the Québec Phase II tie were each limited to 1,200 MW.

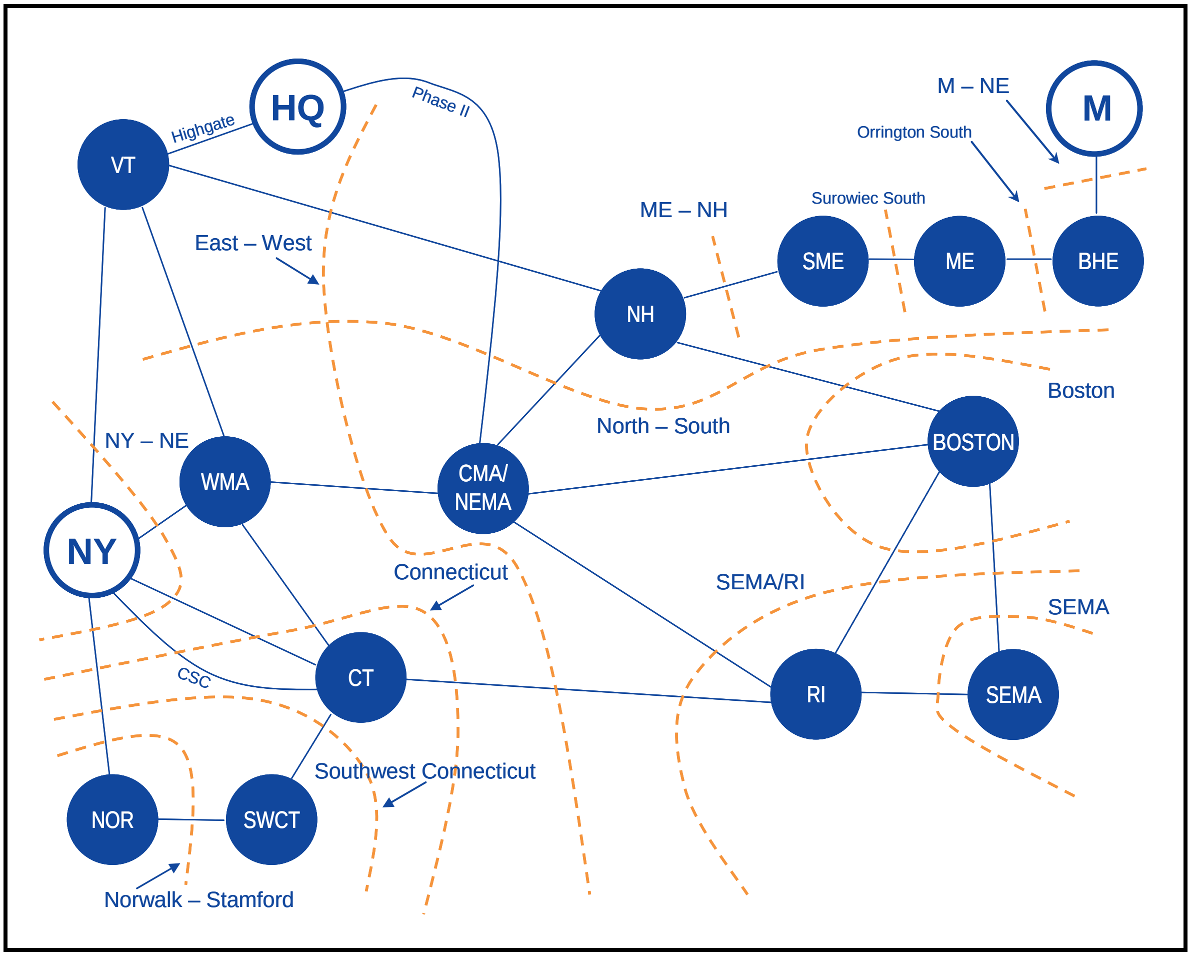

Figure 4-4: Representation of New England subareas and transmission interfaces.

4.2.2 Results of Subarea Resource Adequacy Analysis

The results show that the LOLE for the NOR subarea will vary the most with load and capacity variations, followed by SWCT, CT, and BOSTON. Accordingly, reducing demand through conservation or demand-response resources, adding new generation, and upgrading the transmission system into these subareas would provide the most effective LOLE benefits.

Table 4-6 summarizes the locations most suitable for adding resources to meet the systemwide LOLE criteria on the basis of this analysis. As shown, adding resources or reducing load in the Greater Connecticut area (NOR, SWCT and CT) would have the greatest impact on reducing systemwide LOLE. Reducing load or adding resources in other subareas south of the North–South interface has LOLE benefits up to approximately 2,000 MW in SEMA/RI and to 3,500 MW in BOSTON, CMA/NEMA, and WMA. Reducing load or adding resources above 700 MW in the Maine subareas contributes minimal benefits to systemwide LOLE in the long run because the resource needs are in the subareas of the Greater Connecticut area. The various transmission limits would reduce the load-serving capability of the resources located in Maine.

Table 4-6
Effectiveness of Adding Resources in Various Locations for Meeting Systemwide LOLE Criterion for 2015/2016

Subarea	Most Constraining Interface	Megawatts Added and Impacts[(a), (b)]				
		0 MW--------->	500 MW---->	1,000 MW-->	1,500 MW-->	Above 2,000 MW
BHE	Orrington–South	Least effective option; can add up to 500 MW				
ME/SME	Maine–New Hampshire	Less-effective option	Least effective option; can add up to 700 MW		**Ineffective**	
NH/VT	North–South		Less-effective option	Least effective option; can add up to 1,300 MW		
SEMA/RI	SEMA/RI Export	**Most effective option**		Less-effective option	Least effective option; can add up to 2,000 MW	
BOSTON CMA/NEMA WMA	Connecticut Import		**Most effective option**	Second-most effective option	Less-effective option	Least effective option; can add up to 3,500 MW
CT/SWCT/NOR	None			**Most effective option**	**Most effective option**	**Most effective option**

(a) The analysis assumed that 2,000 MW of tie benefits (1,200 MW from Quebec, 600 MW from New York, and 200 MW from the Maritimes) can be obtained when the system needs capacity.

(b) In addition to LOLE, many other factors, including ease of interconnecting to the system, influence the addition of system resources.

4.3 Summary of Key Findings

The systemwide probabilistic LOLE analysis demonstrates that by 2009 the New England system will lack the resources necessary to supply load as required by NPCC and ISO criteria, assuming 2,000 MW of tie-line benefits. While it may be assumed that New England will be able to purchase this amount of resources from outside the region when needed, the actual amount that will be available is uncertain.

Additional capacity resources will be needed sooner than 2009 if less emergency assistance is deemed available from the neighboring systems. Results indicate that with no added capacity, New England will need to rely on OP 4 actions to balance load and resources, maintain system reliability, and avoid disconnecting load. More generating-unit retirements and forced outages would also worsen the capacity situation.

Resource adequacy studies show that Greater Connecticut is the most critical area of New England. The Greater Southwest Connecticut area and the Greater Connecticut area are most at risk of experiencing elevated levels of LOLEs with any increase in load or decrease in resources. While the Greater Southwest Connecticut's LOLE and resource adequacy will improve when the Southwest Connecticut Reliability Project Phase 1 and Phase 2 are complete (see Section 8.3), the situation for Greater Connecticut is less robust. Greater Connecticut needs increased resources to meet its long-term needs and provide overall benefit to New England as a whole for meeting load and established reliability criteria. Transmission improvements will also be required in Greater Connecticut (see Section 8.2.2).

On the basis of the results of the systemwide probabilistic and deterministic analyses and subarea deterministic analysis, additional resources are needed by 2009 to meet the New England resource-adequacy criterion and minimize the risk of disconnecting firm load. Results of the subarea analysis show that internal transmission constraints increase the system loss-of-load expectation and limit the benefits that installing generating resources provides to certain subareas.

In summary, to meet system reliability criteria, new resources will be needed during the study period. Total new resource needs range from 3,100 MW to 6,400 MW depending on the amount of emergency assistance New England is willing to rely on to meet its planning reliability criterion. Assuming 2,000 MW of tie-line benefits, New England would need approximately 170 MW by summer 2009, increasing annually to a total requirement of 4,300 MW by 2015. Adding new resources in the Greater Connecticut subareas of NOR, SWCT, and CT would contribute the most to system resource adequacy compared with adding resources in other subareas. The next-most preferred location for adding new resources is BOSTON, CMA/NEMA, or WMA. Less-desirable locations for adding resources are in the subareas located north of the North–South interface. Only a limited amount of capacity can be added in these subareas without reaching the various transmission-transfer limits that prevent resources from flowing to areas of need and minimizing the risk of LOLE events across New England.

New England could also meet its resource needs through energy efficiency, conservation, and load management, improved unit availability, and purchases of firm capacity from neighboring control areas. For the long term, developing generation and demand-response resources, as well as increasing energy efficiency and conservation, will be necessary.

Section 5
Operating Reserves and Demand-Side Resources

In addition to the bulk power system's requiring a certain level of resources to reliably meet the region's actual demand for electricity, as discussed in Section 4, the system requires some of its resources to have certain operating characteristics. The overall mix of resources must be able to quickly respond to system contingencies related to equipment outages and forecast errors, provide regulation service for maintaining operational control, and serve or reduce peak loads during high-load conditions.[67] A suboptimal mix of these operating characteristics could require the ISO to use more costly resources to provide the needed services. In the worst case, reliability would be degraded.

Fast-start and demand-response resources have the operating characteristics to provide operating reserves for responding to contingencies, maintaining operational control, and serving peak demand. Market mechanisms play a role in increasing the availability of these resources by providing opportunities for suppliers to recover the fixed costs associated with making these resources more flexible and able to respond to contingencies. The markets also compensate these resources for opportunity costs and send appropriate economic signals when the resources are in short supply.

This section discusses operating reserves and fast-start and demand-response resources and the market mechanisms that provide incentives for investing in and providing these resources. It also discusses how linking the wholesale and retail electric energy markets is a market means to attain efficient consumption levels at peak and off-peak hours.

5.1 Operating Reserves

A certain amount of the bulk power system's resources must be available to provide operating reserves to assist in addressing systemwide contingencies, as follows:

- Loss of generating equipment within the New England Control Area or within any other NPCC control area
- Loss of transmission equipment within or between NPCC control areas, which might reduce the capability to transfer energy within New England or between the New England Control Area and any other control area

Operating reserves also provide regulation service, which includes providing tie-line regulation and securing the operation of the system against errors in forecasting New England loads.

The ISO's operating-reserve requirements, as established in Operating Procedure No. 8, *Operating Reserve and Regulation* (OP 8), protect the system from the impacts associated with a loss of generating equipment within New England.[68] According to OP 8, during normal conditions, the ISO must maintain a sufficient amount of reserves to be able to replace the first-contingency loss (N-1) in the New England Control Area within 10 minutes. Typically, the first-contingency loss is at least 1,200 MW. In addition, OP 8 requires the ISO to maintain a sufficient amount of reserves to be able

[67] *Regulation* is the capability of specially equipped generators to increase or decrease their generation output every four seconds in response to signals they receive from the ISO to control slight changes on the system. This capability is necessary to balance supply levels with the second-to-second variations in demand.

[68] See http://www.iso-ne.com/rules_proceds/operating/isone/op8/index.html for more information on OP 8.

to replace at least 50% of the second-contingency loss (N-2) within 30 minutes. Typically, 50% of the second-contingency loss is 600 MW.

To protect the system from a loss of transmission equipment within New England, the ISO plans and operates the system in accordance with NERC, NPCC, and ISO criteria. These criteria require the bulk power system to withstand a set of contingencies that includes the loss of transmission facilities or generating units. ISO Operating Procedure No. 19, *Transmission Operations* (OP 19), requires the system to operate such that when any power system element is lost (N-1), power flows remain within applicable emergency limits of the remaining power system elements.[69] This N-1 limit may be a thermal, voltage, or stability limit of the transmission system. OP 19 further stipulates that within 30 minutes of the loss of the first-contingency element, the system must be able to return to a normal state that can withstand a second contingency. This N-2 constraint is met by maintaining an operating reserve that can increase output when the first contingency occurs.

The generating units that provide operating reserves in New England respond to contingencies within 10 or 30 minutes by offering either 10-minute nonsynchronized (nonspinning) reserves (TMNSR) or 30-minute operating reserves (TMOR) (spinning or nonspinning). Spinning reserve is generation that is already on line and can increase output. Nonspinning reserves are off-line fast-start resources that can be electrically synchronized to the system and quickly reach rated capability. Dispatchable asset-related demand (DARD) (i.e., demand that can be interrupted within 30 minutes in response to a dispatch order) can also provide operating reserves, serve or reduce peak loads, and avert the need to dispatch more costly resources to supply operating reserves.

5.1.1 Systemwide Needs for Operating Reserves

The ISO System Operations Department identifies the resources needed the next day in transmission-constrained areas to meet N-1 or N-2 limits, ensure reliability, and prevent the need to initiate emergency procedures, including disconnecting some firm load. The analysis takes into account the projected peak load of the area, the largest contingency in the area, possible resource outages, and expected transmission-import limits. Generating resources within the load pocket studied are committed to meeting the following day's requirements to withstand the occurrence of two contingencies on the basis of the results of each assessment.

The current Forward Reserve Market was designed to provide economic incentives to those resources that provide off-line reserves (fast-start resources), especially peaking units that are seldom dispatched in the electric energy market. The market procures in advance the operating-reserve capability needed to meet the expected TMNSR and TMOR required for the New England Control Area.

More than 90% of the time, the fast-start resources that provide reserves are those designed and installed to provide off-line reserve. These resources rarely operate to meet the overall electric energy needs of the system and therefore receive limited revenues from the wholesale electric energy market. In contrast, a unit that must be on line to provide reserves is eligible to receive the locational marginal price (LMP) and compensation for any additional costs associated with its minimum run-time commitment (i.e., its start-up and no-load costs) that are not recovered through the market. The SMD settlement rules of the wholesale electric energy markets guarantee the recovery of these additional costs through reliability payments. As a consequence of this treatment, without the revenues provided

[69] See http://www.iso-ne.com/rules_proceds/operating/isone/op19/index.html for more information on OP 19.

by the Forward Reserve Market, off-line reserves would receive only capacity payments with which to maintain the availability of equipment and to invest in additional equipment.

A two-phase Ancillary Services Market project (ASM I and ASM II) is enhancing the SMD, a part of which includes the implementation of appropriate locational forward and real-time markets for acquiring operating reserves. Phase I, implemented in October 2005, included improving the design of the Regulation Market, changing the re-offer period, and revising software to improve external price setting.[70] ASM II, to be implemented in the fourth quarter of 2006, will improve the current FRM with the following enhancements related to resource operating characteristics:

- A locational reserve requirement will more accurately reflect the operational constraints of the system.
- A portfolio-offer capability will allow suppliers of reserves to replace (on a daily basis) unavailable resources with another resource or use a bilateral trade to cover their reserve obligation.
- The co-optimization of real-time dispatch and the pricing of electric energy and reserves will allow for simultaneously meeting system and local reserve constraints as well as electric energy and transmission constraints.
- Dispatchable asset-related demand resources will be able to participate directly in the wholesale electric energy market in a manner comparable to generation resources. Those resources that meet the 10- and 30-minute response-time requirements will be able to qualify as fast-start resources.
- Performance monitoring will be improved, and the penalty structure will be modified.

These market enhancements are designed to provide market incentives to investors to meet both systemwide and local reserve needs.

5.1.2 Operating-Reserve Requirements in Greater Southwest Connecticut, Greater Connecticut, and BOSTON

Subareas require operating reserves for secure and economical operation, specifically, to protect against the worst generation or transmission contingency. These may vary as a function of system conditions, including load levels, unit dispatch, system configuration, and special circumstances, such as the common-mode failure of Mystic Units #8 and #9. The amount and type of operating reserves a subarea needs depend on the reliability constraints of the system and the characteristics of the generating units within the subarea. Resources located within a subarea, outside the area, or a combination of both can provide operating reserves for the subarea. The types of reserves that can be used are also flexible and include spinning reserves, fast-start resources, and dispatchable asset-related demand.

Subareas that rely on resources located outside the area to provide operating reserves must have adequate transmission-import capability. Subareas with local reserve requirements greater than available DARD plus fast-start generation, and without sufficient in-merit generation (based on

[70] The Regulation Market is the mechanism for selecting and paying the generation needed to manage the constant small changes in the system's electrical load. The re-offer period occurs after the New England's Day-Ahead Energy Market clears. During this period, generators are able to re-offer uncommitted capacity to the market (see AMR05).

accepted and scheduled supply offers), require additional internal generation to provide spinning reserve (local second-contingency resources). These resources are paid reliability payments called Net Commitment-Period Compensation (NCPC) (formerly known as operating-reserve credits), an additional unhedgable cost to load-serving entities.[71] Operating experience has demonstrated that the ISO frequently commits generation out of economic-merit order to provide the required second-contingency protection in the transmission-constrained areas of Greater Southwest Connecticut, Greater Connecticut, and BOSTON. These commitments increase reliability payments and distort marginal prices.

Table 5-1 shows representative future operating-reserve requirements for Greater Southwest Connecticut, Greater Connecticut, and BOSTON. These needs are based on the methodology for calculating the requirements for the locational Forward Reserve Market. The estimated requirements are calculated on the basis of representative future system conditions for load, generation availability, N-1 and N-2 transfer limits, and the largest generation contingencies in each subarea. Actual market requirements will be calculated immediately before the locational FRM procurement period on the basis of historical data that reflect actual system conditions. The table also shows the existing amount of fast-start capability in each subarea.

[71] Net Commitment-Period Compensation is the methodology used to calculate payments to resources for providing operating or replacement reserves in either the Day-Ahead or Real-Time Energy Markets (subject to limitations). The accounting for the provision of these services is performed daily and considers a resource's total offer amount for generation, including start-up fees and no-load fees, compared to its total energy-market value during the day. If the total value is less than the offer amount, the difference is credited to the market participant. For more information, see *Market Rule 1*, Section III, Appendix F, *Net Commitment Period Compensation Accounting*, at http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_appendix_f.pdf.

Table 5-1
Representative Future Operating-Reserve Requirements in Major New England Import Areas (MW)

Area/Improvement	Market Period[a]	Existing Amount of Fast-Start Resources (MW) [b]	Representative Future Locational Forward Reserve Market Requirements (MW): Summer (June to Sept.)	Winter (Oct. to May)
Greater Southwest Connecticut		427 (summer)[c] 513 (winter)		
	2006		No locational FRM	550[d]
With SWCT Reliability Project Phase 1[e]	2007[f]		500–600	400–500
	2008		400–500	400–500
	2009		400–500	400–500
With SWCT Reliability Project Phase 2[e]	2010[g]		400–500	0
Greater Connecticut		662 (summer)[h] 831 (winter)		
	2006		No locational FRM	1,340[d]
	2007		1,200	1,200
	2008		1,200	1,200
	2009		1,200	1,200
	2010		1,200	1,200
BOSTON[i]		226 (summer) 335 (winter)		
	2006		No locational FRM	910[d]
With NSTAR 345 kV Transmission Reliability Project (Phase I)[e]	2007		900–1,300	0
With NSTAR 345 kV Transmission Reliability Project (Phase II)[e]	2008		300–700	0
	2009		50–400	0
	2010		150–500	0

(a) The market period is from June 1 through May 31 of the following year.

(b) These values are based on the resources' seasonal claimed-capability ratings (i.e., the maximum dependable load-carrying ability of a generating unit, excluding the capacity required for station use) and do not account for outage adjustments.

(c) This value does not include SWCT Emergency Capability Resources (see Section 4.1.1.1 and Section 5.2.1).

(d) These values are based on actual historical data. Data for future years are projected on the basis of assumed contingencies.

(e) The requirements are based on in-service dates provided by the transmission owners.

(f) The requirement is based on ISO operations resource adequacy process (see Section 4).

(g) The requirement is based on the ISO's resource adequacy process and assuming that operating reserve could be imported from outside the subarea.

(h) This value does not include SWCT Emergency Capability Resources but does include other resources in Greater Southwest Connecticut.

(i) The values for BOSTON are lower when load is shed in response to an N-2 transmission contingency, without consideration of the Mystic Units #8 and #9 common-mode failure.

Because the local contingency requirements in Greater SWCT are nested (i.e., operating reserves that meet the Greater SWCT requirement also meet the Greater Connecticut requirement), installing the fast-start resources, dispatchable asset-related demand, or baseload resources in the Greater SWCT area would address the need for resources anywhere in Greater Connecticut.

5.1.2.1 Greater Southwest Connecticut

The year-to-year changes in operating-reserve requirements for Greater SWCT, as shown in Table 5-1, are a result of anticipated load growth and the increased import limits expected from the transmission upgrades currently under construction in that area (see Section 8). As the transmission-import limits increase for this area, the system operators will have more flexibility to use more of the generation located within and outside the subarea to meet load and reserve requirements. If maximizing the use of the transmission-import capability to meet demand is more economical, the subarea will require higher operating reserves to protect for the N-2 contingency. If using import capability is less economical, generation located outside the subarea could be used to provide operating reserves, thus minimizing or eliminating operating-reserve support within the subarea.

As shown in Table 5-1, the 427 MW of fast-start resources in the Greater Southwest Connecticut area currently meets most of that area's local second-contingency operating-reserve requirement. To meet the summer operating-reserve requirement for 2007, 75 MW to 175 MW of additional resources will be required. The amount of operating-reserve requirement is expected to decrease with the addition of the transmission improvements that increase the import capability into this area.

5.1.2.2 Greater Connecticut

The need for additional resources in Greater Connecticut to alleviate reliability and economic considerations can be met by adding dispatchable asset-related demand, fast-start resources, or resources with electric energy prices competitive with those resources external to the subarea. Greater Connecticut has 662 MW of fast-start resources; up to 540 MW of additional fast-start resources could be needed to meet the current 1,200 MW requirement for operating reserves.

5.1.2.3 BOSTON

As shown in Table 5-1, the operating-reserve requirements for the BOSTON Subarea, which depend on the economics of operating the generating units within and outside the subarea, were obtained by evaluating load growth in conjunction with the increased import limits expected from the proposed transmission upgrades for the area (see Section 8.3). The analysis reflects the possible contingency of the simultaneous loss of Mystic Units #8 and #9. Additionally, the representative future locational Forward Reserve Market requirements reflect the addition of the NSTAR 345 kV Transmission Reliability Project Phase I and Phase II. As the import limits increase into BOSTON, operators will be able to optimize the use of this generation to meet load and reserve requirements. If the transmission lines were fully utilized to import lower-cost generation into BOSTON, this subarea would need to provide operating reserves to protect against the larger of either the loss of the largest generation source or the loss of a transmission line within the subarea.[72]

5.1.2.4 Summary of Operating-Reserve Requirements in Major Load Pockets

Adding dispatchable asset-related demand or fast-start resources in either Greater SWCT or Greater Connecticut load pockets would provide much needed operating flexibility and operating reserves if

[72] In some circumstances when transmission contingencies are more severe than generation contingencies, shedding some load may be acceptable.

the transmission interface became loaded near its N-1 limit. Alternatively, adding baseload resources that are on line most of the time in these areas would allow the use of reserves from outside areas. These internal resources typically bid less than resources external to the load pockets and can reduce flows across the transmission interfaces into these areas.

5.2 Demand-Side Resources

This section discusses the potential capacity from demand-side resources, including demand-response resources, conservation, and energy efficiency. It also discusses the linking of the wholesale and retail electric energy markets as a market mechanism for attaining an efficient allocation of load between peak and off-peak periods.

5.2.1 Capacity Available from Demand-Response Resources

The demand-response program assets considered to provide capacity include resources participating in the Real-Time Demand-Response Program and the Real-Time Profiled Response Program.[73] These resources are activated during various OP 4 action steps. Approximately 260 MW of real-time demand-response resources located in SWCT are under Supplemental Capacity Agreements with the ISO. These resources were selected through the SWCT Gap RFP. Table 5-2 lists the demand-response capacity assumed in the installed capacity analysis for 2006 to 2007 (see Section 4.1.1), classified by SMD load zone.

Table 5-2
Capacity Data Assumed for 2006–2007 Demand-Response Programs

Program[(a)]	SMD Load Zone	MW Assumed in 2006-2007		Performance Rate (%)
		Summer	Winter	
Real-Time 2-Hour Demand Response	SWCT	0.7	0.7	65.5
	ME	1.0	1.0	100.0
	NEMA/Boston	0.8	0.8	1.2
	WCMA	9.0	9.0	77.6
Real-Time 30-Minute Demand Response	SWCT	256.8	173.3	92.2
	CT	23.9	23.9	89.7
	NEMA/Boston	2.8	2.8	55.0
	SEMA	0.5	0.5	31.0
	VT	0.1	0.1	96.3
	WCMA	0.1	0.1	100.0
Profiled Response	ME	11.0	11.0	77.6
	NEMA/Boston	1.4	1.4	89.4
	VT	5.9	5.9	100.0
Total		**314.0**	**230.5**	

(a) For more information on these programs, see http://www.iso-ne.com/genrtion_resrcs/dr/broch_tools/index.html.

[73] For more information on these programs, see http://www.iso-ne.com/genrtion_resrcs/dr/broch_tools/index.html.

In response to concerns about natural gas availability following Hurricanes Rita and Katrina in fall 2005, the ISO implemented a Winter Supplemental Program (WSP) offering additional payments to real-time demand-response resources available from December 2005 through March 2006. Because the WSP resources were available for the short term, they were not included in the capacity forecast.

Improvements to the demand-response programs in 2005 included the introduction of the Day-Ahead Load-Response Program and the FERC's approval of the ISO's tariff revisions to establish the Demand-Response Reserve Pilot Program (DRR Pilot).[74] The Day-Ahead Load-Response Program is an optional program that allows a participant in one of the real-time programs to offer interruptions concurrent with the Day-Ahead Energy Market. The participant is paid the day-ahead LMP for the cleared interruptions. Real-time deviations are charged or credited at the real-time LMP.

The objective of the DRR Pilot is to determine whether smaller (less than 5 MW) generation and demand-response resources can provide a reserve product that is functionally equivalent to a traditional generation resource. The 12-month pilot, to begin in the fourth quarter of 2006, will test the responsiveness of smaller generation and demand-response resources to more-frequent and shorter-duration activations. The DRR Pilot will consist of two distinct subprojects:

- Determining the ability of demand resources to respond to reserve-activation events, compared with off-line and on-line generation resources
- Evaluating the features of lower-cost, two-way communication alternatives, compared with the current combination of SCADA and Electronic Dispatch Remote Intelligent Gateway technology now required to connect dispatchable resources to the ISO[75]

5.2.2 Impacts of Conservation and Energy Efficiency on the Annual and Peak Use of Electricity

The ISO will continue to explicitly adjust its control area and state long-run forecasts of annual and peak electricity use to reflect use reductions as a result of utility-sponsored conservation and peak-load management programs (see Section 3.2). Table 3-4 details these reductions.

The historical demand-side management (DSM) savings are combined with the historical electricity-use data used to estimate the long-run electric energy models. The resulting electricity-use forecast excludes the impacts of these utility-sponsored programs but captures any ongoing conservation trends. The forecasted DSM electric energy reductions are then subtracted from the forecast. The load-factor methodology used to forecast the long-run seasonal peaks explicitly incorporates the DSM in a similar manner.

5.2.3 Alignment of Retail and Wholesale Electricity Markets

Another mechanism that will reduce peak loads is the development of retail electric energy rates that foster dynamic pricing. Dynamic pricing involves using rate structures designed to encourage retail customers to respond to price signals that more closely reflect the supply and demand conditions of the wholesale electric energy market. These rate structures include rates for interruptible and curtailable loads and related demand-call options, real-time pricing, and critical-peak pricing. Because these retail rates are generally indexed to wholesale electric energy prices, retail customers

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[74] FERC, *Letter Order Accepting Amendments to Appendix E of Market Rule 1 to Establish a Demand-Response Reserve Pilot Program*, FERC Docket No. ER05-1450-000 (Nov. 29, 2005).

[75] *SCADA* refers to "supervisory control and data acquisition."

would be encouraged to reduce load during high-cost, peak-period hours. Reducing electricity demand, by even a modest amount at times of high wholesale electric energy prices, has a number of advantages. In addition to helping to lower the electric energy price for all retail customers and contributing to the more efficient use of resources, reducing demand reduces the use of more expensive generation.

The ISO recently commissioned a study that addresses dynamic retail pricing.[76] The report estimated the wholesale market impacts that would result from increasing the penetration of dynamic pricing among larger commercial and industrial customers. The study concluded that if about one-third of all the New England customers over 1 MW (representing a peak demand of 1,600 MW) reduced their electricity consumption in response to a retail rate indexed to day-ahead prices, the financial benefits over five years to all New England consumers would be approximately $340 million.

5.3 Summary of Key Findings

Short-lead-time, fast-start resources and demand response can satisfy near-term operating-reserve requirements, while providing operational flexibility to major load pockets and the system overall. Locating baseload generation in major load pockets can allow for the use of reserves from outside areas.

Given the region's declining load factors (as discussed in Section 3), shaving the system peak through nonemergency demand response, conservation, and energy efficiency can help meet short-term needs and use existing transmission, generation, and other infrastructure more efficiently. These measures can also provide long-term benefits, such as reducing the need to add capacity or transmission or reducing the use of natural gas to fuel power plants (see Section 6).

Market improvements will help send the correct signals for developing new operating-reserve resources in the most appropriate locations. These resources will be available when system resources are short, and they will be able to meet 10- and 30-minute response-time requirements. These operating characteristics will enhance the reliable and economic operation of the system. Aligning the retail electricity market with the wholesale market will allow consumers to adjust load in response to prices, which will help lower the electric energy price for all retail customers and contribute to the more efficient use of resources.

[76] Neenan, B., et al., *Improving Linkages between Wholesale and Retail Markets through Dynamic Retail Pricing,* December 5, 2005, Neenan Associates, LLC (a UtiliPoint International Company).

Section 6
Fuel Diversity

The New England region faces serious challenges regarding the current mix of fuels it uses to generate electricity and the corresponding delivery systems for these fuels. The challenges can be categorized as follows:

- **Short-term seasonal reliability issues—**In New England, winter reliability has been an area of major concern especially following the January 14–16, 2004, cold snap (January 2004 Cold Snap).[77] In addition, the unforeseen catastrophic results of Hurricanes Katrina and Rita exacerbated supply-chain concerns for both natural gas and oil during fall 2005.
- **Near-term economic consequences of continuing to use the current mix of fuels—**For the next several years, New England will continue to rely on natural gas and oil to produce the majority of its electricity.
- **Long-term task of siting alternative fuel facilities to supplement the region's use of traditional fossil fuels—**More than 60% of the electricity generation within the region is fueled by natural gas and/or oil (heavy and light). In the near term, this percentage will continue to grow as sources for alternative supplies remain under development. A failure to develop alternate fuel sources in the long term could result in further exposure to high electric energy prices and significant price volatility.

This section discusses the short-, intermediate-, and long-term issues related to fuel diversity within New England. Statistics on the current mix of fuels and the amount of electricity generated by the various fuels are presented. The section also discusses the risks to the fuel-supply chain, actions to reduce these risks, and the results of other fuel-supply studies.

6.1 Fuels Used to Generate Electricity in New England

Figure 6-1 depicts the mix of fuels regional generators use to produce electricity, expressed in summer capacity ratings for 2006 (MW and associated percentages). Fossil fuels, such as natural gas, oil, coal, and others, supply over 72% of the installed capacity within New England. As shown, natural gas represents the largest amount of installed capacity at 38%, totaling 11,803 MW. Oil-fired generation is the second-largest component at 7,549 MW, or approximately 24%. Nuclear generation accounts for approximately 4,448 MW, or 14%, and coal-fired generation accounts for approximately 2,846 MW, or 9%. Total renewables, including hydro, are 8.5%, and pumped storage hydro (not a renewable) is 5.4% of the total capacity in New England.

[77] During January 14–16, 2004, New England experienced extremely low temperatures and a record winter-peak demand. For additional information on the ISO's Cold Snap Task Force and related reports, see http://www.iso-ne.com/pubs/spcl_rpts/2005/index.html.

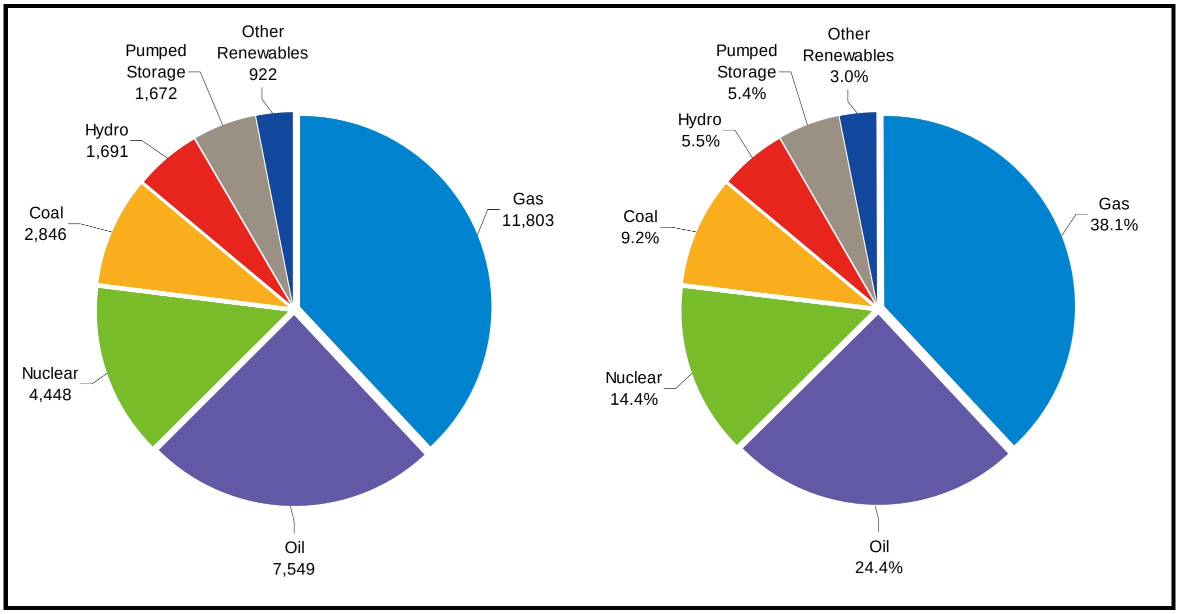

Figure 6-1: NEPOOL generation capacity mix by primary fuel type, 2006, summer ratings (MW and percentage).

Note: "Other Renewables" includes biomass, refuse, landfill gas (LFG), and wind. (See Section 6.4.4.1 and Section 7 for more information on renewable sources of energy.)

Figure 6-2 shows the production of electric energy by fuel type for 2005. As shown, natural gas, nuclear, oil, and coal fueled the majority of the region's electricity production. In total, fossil fuels accounted for over 62% of the production of electricity within New England in 2005. In addition, New England imported 6,297 MWh, or 4.6% of net energy for load.

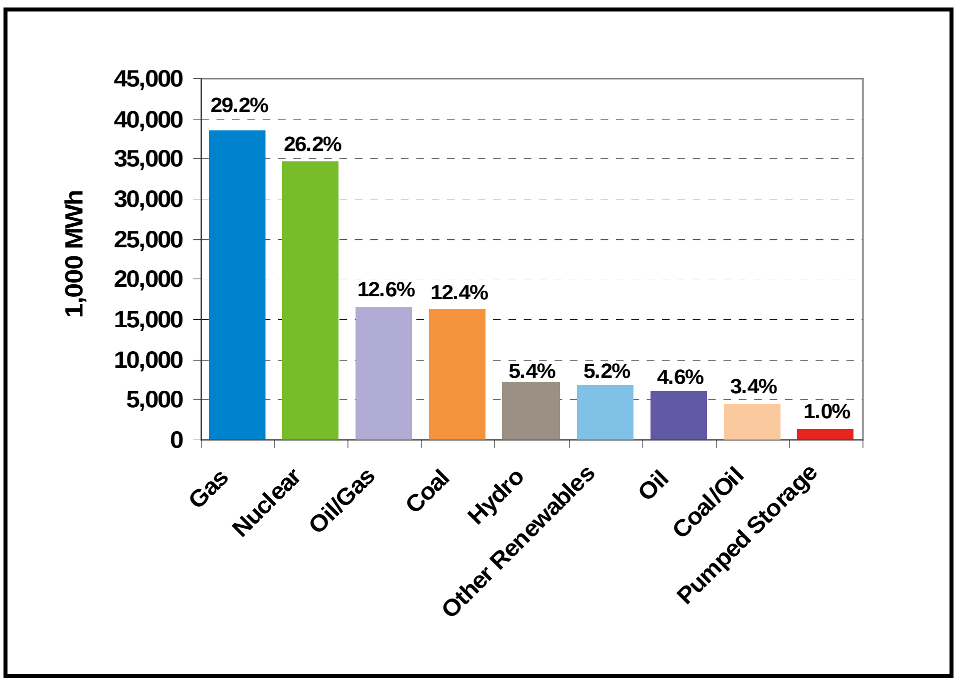

Figure 6-2: NEPOOL electric energy production by fuel type, 2005 (1,000 MWh).

Note: "Other Renewables" includes biomass, refuse, landfill gas, and wind.

6.2 Fuel-Supply Risks and Projections of Continued Dependence on Fossil Fuels

Over the years, the North American electric power industry has experienced a multitude of situations in which fuel-supply issues have had a direct impact on the reliability of the electric power system. These situations have been relatively regional in nature and have traditionally been mitigated with regional solutions. However, world events and periods of extreme weather can create persistent regional, as well as national and global, fuel-supply issues.

Fuel diversity and the region's dependence on specific types of fuel for producing electricity have become major issues in New England with respect to seasonal system reliability and near-term planning. As experienced in New England during the January 2004 Cold Snap, an overarching dependence on any single fuel source can threaten the reliability of the bulk power grid. In addition, the harsh effects of the two back-to-back hurricanes (Katrina and Rita) in fall 2005 along the Gulf Coast caused *"Force Majeure"* declarations throughout the oil, natural gas, and refining industries. Hurricane-recovery efforts to repair fuel-supply infrastructure continue to date.[78] Transcontinental shipping of LNG inherently faces numerous obstacles that can also heighten delivery issues. These types of events can affect fuel-supply chains across the nation. Occurrences like these, although infrequent, exemplify how even traditional fuel-supply chains can be temporarily disrupted.

Below is a list of some of the major fuel-supply risks and ongoing concerns that have an impact on New England's electric power sector. While some of the issues are relatively new, others have confronted regional stakeholders for some time:

- The electric power sector continues to face exposure to seasonal concerns. Regional power-sector fuel-supply (gas and oil) risks still linger because of the damage sustained in fall 2005 from the two most destructive hurricanes ever to hit the U.S. energy sector, centered in the Gulf of Mexico. The potential for future storm impacts adds to this risk. In New England, the potential loss of aging regional storage facilities for oil products further compounds this issue. Additionally, New England's gas-fired electricity generators continue to compete with the ever-growing core natural gas market (i.e., for space heating) for supply and finite transportation infrastructure. The Gulf Coast hurricanes caused natural gas and oil prices to reach unprecedented levels.[79] The price volatility created by this and other regional factors directly contributes to high spot-market wholesale electricity prices.
- A fuel-procurement strategy that relies on interruptible or spot-market natural gas contracts makes the seasonal availability of fuels less certain and reduces system reliability.
- Interruptions in the overall supply chain for natural gas risks the operational availability of single-fuel gas-only units.
- The build-out of new gas-fired power generation in neighboring markets exacerbates New England's fuel-supply concerns, as units "upstream" from New England compete for limited supplies and constrained deliverability (transportation).

[78] The current status of Gulf Coast recovery efforts can be found on the U.S. Minerals Managements Service Web site, http://www.mms.gov/. Information on natural gas storage levels is available at the DOE, EIA Web site, http://tonto.eia.doe.gov/oog/info/ngs/ngs.html. Data concerning oil and natural gas drilling rigs can be found on the Baker Hughes Web site, http://www.bakerhughes.com/investor/rig/rig_na.htm.

[79] Refer to the ISO's AMR05 at http://www.iso-ne.com/markets/mkt_anlys_rpts/annl_mkt_rpts/index.html for more information on natural gas and oil prices.

- Regional gas pipeline capacity is not sufficient to serve the coincident demand for natural gas during winter peak-load periods from the core natural gas and electricity generating sectors.
- The lack of coordination between the bidding timelines for the natural gas and wholesale electricity markets creates uncertainty about the nomination of the gas supply needed to fuel gas-fired electrical generating units and thus adds to concerns about the reliability of the electric power system.
- *New Integrity Management Rules* from the U.S. Department of Transportation's (DOT) Office of Pipeline Safety (OPS) mandate increased inspection, testing, and remedial maintenance of natural gas and oil pipelines in the near term. Gas-sector testing and maintenance activities that may affect the delivery of fuel to gas-fired generators will require tighter coordination between the ISO and natural gas pipeline operators.
- Although new LNG import terminals are projected to satisfy incremental gas demand, the commercialization of any one of these new regional facilities is not expected until the 2008 to 2010 timeframe, or later. Extreme weather can cause navigational delays in LNG shipments, as well. Within power markets, global events now dictate where uncontracted LNG cargo will be delivered. While some forecasts show new LNG facilities dampening regional natural gas prices, others suggest that LNG suppliers will seek to maximize their economic returns by pricing and shipping their gas on the basis of market conditions, resulting in only a small affect on natural gas prices.
- New England's generation fleet needs to continuously adapt to and comply with new state- and federally mandated environmental regulations (i.e., to protect air and water). These new regulations may, in turn, cause some non-gas-fired facilities to retire as a result of economic considerations and thus increase the region's dependence on generators that burn natural gas.

These issues, combined with the lack of regional sources of fuel, expose New England to some of the highest fuel transportation costs in the country. With the added consideration of highly volatile commodity costs in the region, the outlook for lowering New England's wholesale electricity prices from their ranking as *"highest in the nation"* is not positive in the near term. Together, these factors keep fuel-supply and diversity concerns in the forefront of regional discussions.

6.3 Fuel-Supply Studies

RSP06 assessed the effects on both systemwide and subarea operable capacity resulting from the loss of gas-only resources within New England. The analysis also modeled the southern New England (SNE) region, which includes the RSP subareas located south of the North–South transmission interface (see Figure 4-4). Each used the same approach as the methodology used to determine summer operable capacity (as discussed in Section 4.1.2), except as indicated, for assuming the unavailability of gas-only generating units. The studies do not reflect resource additions, retirements, or deactivations that could also occur during the planning period.

6.3.1 Systemwide Winter Operable Capacity Assessments

The ISO conducted winter operable capacity assessments for the 2006/2007 to 2010/2011 periods. These assessments identified the amounts of gas-fired generation that would need to be available to result in positive operable capacity margins. Negative operable capacity margins indicate the need for dual-fuel conversion or firm gas contracts.

6.3.1.1 Study Approach

For this study, in addition to assuming the usual amount of pool-wide summer outages, the winter assessment assumed all gas-only units served from pipelines and local distribution companies (LDCs) would be temporarily unavailable as well.[80]

6.3.1.2 Findings

Table 6-1 shows the results of the systemwide winter operable capacity analysis associated with the 50/50 load forecast and assuming that all gas-only generation was temporarily nonoperational. On the basis of these results, New England could experience a negative operable capacity margin of approximately 430 MW during winter 2006/2007. This negative operable capacity margin would grow to 1,800 MW by winter 2010/2011. Table 6-2 shows that New England could experience a negative operable capacity margin of approximately 1,400 MW during winter 2006/2007, assuming gas-only generation outages and winter loads associated with the 90/10 forecast. This negative operable capacity margin reaches approximately 2,800 MW by winter 2010/2011.

Table 6-1
Projected New England Operable Capacity Situation, Winter 2006/2007 to 2010/2011, 50/50 Peak Loads (MW)

Capacity Situation (Winter MW)	2006/2007	2007/2008	2008/2009	2009/2010	2010/2011
Load (50/50)	22,550	22,810	23,160	23,520	23,935
Operating reserves	1,800	1,800	1,800	1,800	1,800
Total requirement	**24,350**	**24,610**	**24,960**	**25,320**	**25,735**
Capacity	33,350	33,350	33,350	33,350	33,350
Net purchases/sales	411	411	411	411	411
Assumed gas-only capacity unavailable	(8,644)	(8,644)	(8,644)	(8,644)	(8,644)
Additional unavailable capacity	(1,200)	(1,200)	(1,200)	(1,200)	(1,200)
Total net capacity	**23,917**	**23,917**	**23,917**	**23,917**	**23,917**
Operable capacity margin[(a)]	(433)	(693)	(1,043)	(1,403)	(1,818)

(a) “Operable capacity margin” equals “total net capacity” minus “total requirement.”

[80] The ISO’s ARR05 contains more information on determining unit outages; see http://www.iso-ne.com/pubs/arr/index.html.

Table 6-2
Projected New England Operable Capacity Situation, Winter 2006/2007 to 2010/2011, 90/10 Peak Loads (MW)

Capacity Situation (Winter MW)	2006/2007	2007/2008	2008/2009	2009/2010	2010/2011
Load (90/10 forecast)	23,475	23,745	24,105	24,475	24,905
Operating reserves	1,800	1,800	1,800	1,800	1,800
Total requirement	**25,275**	**25,545**	**25,905**	**26,275**	**26,705**
Capacity	33,350	33,350	33,350	33,350	33,350
Net purchases/sales	411	411	411	411	411
Assumed gas-only capacity unavailable	(8,644)	(8,644)	(8,644)	(8,644)	(8,644)
Additional unavailable capacity	(1,200)	(1,200)	(1,200)	(1,200)	(1,200)
Total net capacity	**23,917**	**23,917**	**23,917**	**23,917**	**23,917**
Operable capacity margin[(a)]	(1,358)	(1,628)	(1,988)	(2,358)	(2,788)

(a) "Operable capacity margin" equals "total net capacity" minus "total requirement."

On the basis of the systemwide 90/10 winter operable capacity analysis, during winter 2006/2007, New England should not have negative margins, if 1,400 MW of the 8,600 MW of gas-only units are available. In fall 2005, in preparation for winter operations, the ISO determined that approximately 3,000 MW of gas-fired generating units have firm gas pipeline transmission contracts through the five-year study period. If these gas-fired resources remained operational over winter-peak loads, or significant new or expanded dual-fuel capacity were added to the system, New England should have adequate operable capacity margins during the study period.

6.3.2 Subarea Winter Operable Capacity Assessments

Winter operable capacity assessments were conducted for the transmission-constrained load pockets of Greater SWCT, Greater Connecticut, and BOSTON. The objective of this analysis was to determine whether the assumed unavailability of gas-only generation located in these load pockets would drastically affect each area's ability to satisfy native winter-peak demands.

6.3.2.1 Study Approach

To calculate the subarea operable capacity margins, in addition to assuming the fleet would experience the usual amount of forced outages and unit unavailability, the ISO assumed that the gas-only units located in each subarea under review would be temporarily unavailable. The study assumed that supply-side resources would be available elsewhere within the system and that their output could be delivered into these subareas.

6.3.2.2 Findings

The results of the winter operable capacity analysis for Greater SWCT, Greater Connecticut, and BOSTON under both the 50/50 and 90/10 winter-peak load conditions show no negative operable capacity margins during the winter periods of 2006/2007 through 2010/2011. These results show that while these subareas lack adequate transmission import capability, they are currently balanced with respect to the fuel mix of their native generation. The ISO continuously reviews operable capacity to ensure subarea reliability.

6.3.3 Subregional Winter Operable Capacity Assessments

Winter operable capacity assessments were also conducted for the southern New England subregion consisting of RSP subareas located south of the North–South transmission interface (WMA, CMA/NEMA, BOSTON, SEMA, RI, NOR, SWCT, and CT). The objective of this analysis was to determine whether the assumed unavailability of gas-only generation located in this subregion would drastically affect the subregion's ability to satisfy native winter-peak load-pocket demands.

6.3.3.1 Study Approach

To calculate the subregional operable capacity margins, in addition to assuming the fleet would experience the usual (forced) outages and unit unavailability, the study assumed that all of the gas-only units located in the southern New England subregion would be temporarily unavailable.

6.3.3.2 Findings

If the 6,500 MW of gas-only generation located in this subregion were assumed to be unavailable, the southern New England subregion would experience a relatively small negative operable capacity margin in winter 2010/2011 using 50/50 peak loads, or as early as winter 2007/2008 for the 90/10 peak loads. The operability of gas-only units is more critical in southern New England than in the northern portion of the system.

6.3.4 Summary of Fuel-Supply Studies

While nonoperating gas-only units are not expected to have an impact on the operable capacity margins in the subareas, New England would be short of operable capacity during the winter peak if all 8,600 MW of gas-only generation were not operating. As noted earlier, approximately 3,000 MW of gas-only generating units have firm gas transmission contracts through the five-year study period. If these gas-fired resources remained operational, or some degree of new or expanded dual-fuel capacity were added to the system, New England would have adequate winter operable capacity margins through 2010/2011. Southern New England is the preferred location for these units.

6.4 Actions to Reduce Risks

To ensure the reliability of New England's bulk power system, the ISO has undertaken a number of stakeholder initiatives to develop procedures, model rules, and other actions to minimize the potential impacts of the risks associated with the lack of fuel diversity in the region. This section discusses some of the recent actions to reduce these risks. The short-term efforts highlight past experience and a recent initiative to promote the expansion of dual-fuel operability within the existing fleet of power plants. Near-term efforts reflect initiatives within the natural gas sector to satisfy incremental gas demand. The longer-term efforts deal with finding alternative fuel sources to replace the region's growing dependence on and skyrocketing costs of traditional fossil fuels.

6.4.1 Past Mitigation Efforts—Reviewing Winter 2005/2006 Action Plan and Operations

Past mitigation efforts, as discussed in this section, have included the Winter 2005/2006 Action Plan and other remedial activities following the January 2004 Cold Snap, primarily the development of Appendix H of *Market Rule 1* (Appendix H), *Operations during Cold Weather Conditions*.[81]

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[81] *Market Rule 1* Appendix H can be accessed at http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_appendix_h.pdf.

6.4.1.1 Hurricanes Katrina and Rita

The damage caused by Hurricanes Katrina and Rita, which made landfall in New Orleans on August 29, 2005, and East Texas on September 24, respectively, significantly reduced production levels of Gulf Coast oil and natural gas and refining capacity. It was uncertain whether recovery efforts, still ongoing, would meet the formidable requirements for storing gas and oil before the beginning of the 2005/2006 winter heating season.

To assess hurricane damage and compile market intelligence on recovery efforts, the ISO immediately retained the consulting services of Levitan and Associates, Inc.[82] On October 6, 2005, the ISO published Levitan's report, *Post Katrina and Rita Outlook on Fuel-Supply Adequacy and Bulk Power Security in New England.*[83] This assessment found that because of extensive hurricane damage to natural gas infrastructure, gas supplies serving the Atlantic seaboard would be tight, thereby causing natural gas prices to remain at extremely high levels throughout the heating season. The report states that the ISO could effectively manage any loss in electricity production arising from natural gas constraints through the increased use of oil-fired generation that burns residual fuel oil.

6.4.1.2 Development of OP 21 and the Winter 2005/2006 Action Plan

The potential for natural gas supply shortages and pricing concerns that resulted from the damage caused by Hurricanes Katrina and Rita, complicated a number of issues. These issues included the reliability concerns identified during the January 2004 Cold Snap, constrained pipeline capacity into New England, fuel arbitrage, and the disconnect in bidding timelines between the electricity and gas markets. In fall 2005, the ISO created an internal response team to formulate the Winter 2005/2006 Action Plan. The major aspects of this plan are outlined below.

The ISO directly began developing a new operating procedure, Operating Procedure No. 21, *Actions during an Energy Emergency* (OP 21), to mitigate impacts resulting from all types of fuel-supply shortages or other abnormal system conditions. OP 21 was reviewed and revised through the NEPOOL stakeholder review process and coordinated with state authorities. The ISO filed the new procedure with FERC on November 29, 2005, requesting expedited review and implementation prior to winter.[84] The OP 21 FERC filing also contained modifications to *Market Rule 1* that allowed for changes to the out-of-merit posturing of generating units affected by fuel constraints, as well as changes necessary to administer associated costs incurred beyond the traditional single-day settlement period.

An initial fuel survey (Appendix A of OP 21—*Comprehensive Information*) was sent to all fossil-fuel-based asset owners in early November requesting information on their fuel-supply arrangements, storage infrastructure, and inventory/refill capability. A weekly fuel survey (Appendix B of OP 21—*Weekly/Daily Updates*) was also implemented, which obtained information on weekly storage inventories. This information was evaluated with the ISO's weekly electric energy estimates to forecast both short- and near-term reliability on the basis of meeting projections for future electric energy requirements.

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[82] Levitan and Associates, Boston, MA (http://www.levitan.com).

[83] The Levitan and Associates report is available at http://www.iso-ne.com/pubs/spcl_rpts/2005/wntr_assess/post_hurricane_outlook.pdf.

[84] This FERC filing can be accessed at http://www.iso-ne.com/regulatory/ferc/filings/2005/nov/splmntl_wntr_pckg_112905.pdf.

The ISO encouraged gas-only generation to convert to dual-fuel (liquids) capability prior to winter. Approximately 1,400 MW of existing capacity, those stations with existing air permits to fire liquids, responded, installing the necessary hardware and performing the commissioning tests. Another aspect of the Winter 2005/2006 Action Plan was to enroll more demand response to be available for interruption, if needed, during the winter period. Approximately 330 MW of incremental demand response was enrolled for winter 2005/2006.

Additional measures, as follows, were developed and implemented to support reliable winter operations:

- Reviewing all regional natural gas pipeline-capacity contracts for gas-fired generators
- Assessing the availability of gas-fired resources on the basis of regional temperatures and the likelihood that the gas transportation for the resource would be interrupted because higher-priority contract entitlements would be exercised
- Revising communication and contact information within the ISO's *Natural Gas Emergency Information Package*
- Obtaining real-time information from the electronic bulletin board (EBBs) systems of the region's natural gas pipeline operating companies
- Hosting a workshop to reinforce the coordination of winter operations and communications among the ISO and key regional stakeholders
- Proactively coordinating winter operations with both NYISO and PJM to improve the reliability of the interconnected system overall

As required by the OP 21 FERC filing, the ISO produced a post-winter operational assessment that reviewed system operations and performance of the new procedure. The ISO's System Operations Department developed the report, *Assessment of the Effectiveness of ISO New England Operating Procedure No. 21 in Addressing Actual and Potential Energy Emergencies during Winter 2005/2006*.[85] This report concluded that the greatest risk is an inadequate local fuel inventory, which must be monitored. Although the original OP 21 procedures are no longer in effect, the ISO is developing expanded OP 21 procedures that will be in effect the entire year.

6.4.1.3 Review of Winter 2005/2006 Operations

New England experienced one of the mildest winters on record during 2005/2006. From December 1, 2005, through March 31, 2006, the ISO had no need to implement OP 4, OP 21, or Appendix H of *Market Rule I*. In addition, over the specified period, none of the ISO's two-day or seven-day forecasts projected the need to implement any of these operating procedures or market rules.

6.4.2 Short-Term Risk Mitigation—Maximizing Dual-Fuel Operability

One method for the power sector to reduce the impacts from unforeseen disruptions in the fuel-supply chain is to have more than one fuel type available. In general, power plants that can switch from a primary fuel source to a secondary fuel source should be able to remain available during fuel-supply

[85] This report can be accessed at http://www.iso-ne.com/pubs/spcl_rpts/2006/op21_review_rev3.pdf.

constraints. In New England, the majority of such dual-fuel plants burn either natural gas or oil. Promoting the expansion of dual-fuel operability has been a goal of the ISO over the past five years.

In a recent assessment of winter seasonal claimed capability (WSCC), the ISO reported that 79 units totaling 17,360 MW are currently either gas-only or dual-fuel generators, capable of firing natural gas as a start-up, primary, secondary, or stabilization fuel source. Of this number, 31 units totaling 5,723 MW are currently dual-fuel capable. The ISO assumes these units could switch from natural gas to a liquid fuel source if economics were warranted or if they were dispatched to do so for reliability. Twenty-nine of the units, totaling approximately 9,844 MW, have been identified as single-fuel-source units, capable of burning only natural gas. Of this 9,844 MW of gas-only generation, 19 units totaling 5,779 MW are permitted for gas-only operation.[86] The remaining 10 units, totaling 4,065 MW, hold air permits for dual-fuel operation. It is these 10 gas-only units that have been identified as the most suitable candidates for immediate dual-fuel conversion.

6.4.3 Near-Term Risk Mitigation—Addressing Gas-Sector and Supply-Chain Concerns

Through the PAC's involvement in developing the Regional System Plans, as described below, the ISO and regional stakeholders continually assess most fuel-diversity concerns. However, these concerns are still prevalent.

6.4.3.1 Possible Fuel-Diversity Initiative for New England

At the April 5, 2006, PAC meeting, the ISO requested guidance on whether a fuel-diversity metric or criterion or both should be developed for New England to enhance the regional planning process. It also asked what would be the most effective way to undertake such an initiative, if found to be necessary. Acknowledging that the ISO, PAC, and regional stakeholders will be focused on issues relating to implementing the Forward Capacity Market (see Section 4.1.3), most participants at the meeting questioned whether starting a new initiative was timely. The PAC suggested that the ISO separate the fuel-diversity issue into two main tasks. One task would be to identify short-term reliability concerns related to seasonal operability and propose remedies. The second would be to identify long-term strategic fuel-diversity goals. As part of RSP06, the ISO has developed specific LOLE studies that may be useful to these efforts.[87]

6.4.3.2 Identification and Understanding of Gas-Sector Maintenance Activities

At the May 9, 2005, meeting of the Electric/Gas Operations Committee (EGOC), attended by representatives of the ISO and the regional natural gas sector, the ISO requested increased coordination with the regional gas sector. This coordination would help it identify and then assess planned gas-sector maintenance activities for pipelines and LDCs that can affect fuel deliveries to gas-fired power generators. The Northeast Gas Association (NGA), through its member companies, agreed to provide the necessary contacts and expertise to support this near-term goal. The ISO is currently revising its annual, monthly, and weekly *Generation Maintenance Schedule* to incorporate this type of information, which will then be coordinated with short- and long-term transmission-maintenance activities to ensure overall system reliability.

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[86] The 9,844 MW total includes Mystic Units #8 and #9 fueled by LNG.

[87] Detailed results of subarea resource adequacy needs are documented in the ISO's report, *2006 Resource Adequacy Analysis*, posted at the ISO password-protected site, http://www.iso-ne.com/trans/sys_studies/rsp_docs/rpts/2006/final_rsp06_resource_adequacy.pdf. Contact ISO Customer Service at (413) 540-4220 for additional information.

6.4.3.3 Current and Future LNG Supply-Chain Issues Affecting the Regional Development of LNG Facilities

The ISO encourages the development of projects that will increase the region's access to new or incremental natural gas supplies. The natural gas industry is projecting that incremental gas demand will most likely be satisfied by new LNG import terminals. The injection of new natural gas supplies (regassified LNG) directly into New England's gas grid would provide greater operational flexibility for pipeline operators. It would also benefit the development of new contractual services tailored to the unique needs of gas-fired generators (e.g., load-following services).

As discussed in RSP05, regional proposals to develop LNG import terminals have almost doubled. As of this publication, the Northeast Gas Association reports that 16 LNG facilities have been proposed within the greater northeastern United States and eastern Canada.[88] All are in various stages of permitting and development. Currently, the nation has six operational LNG terminals.[89]

Although the commercialization of a new LNG import terminal would help satisfy the fuel-supply needs of the region's gas-fired fleet, this is only a partial solution because of the additional concerns associated with this effort. The lack of uncontracted liquefaction facilities and staffing for new LNG carriers are two hurdles to overcome. Another relates to the interchangeabilty between natural gas and LNG. Some of the current and future LNG supply-chain issues and concerns are as follows:

Lack of Liquefaction Facilities: The global LNG trade can be broken into four "value-chain" components: 1) exploration and production, 2) liquefaction, 3) shipping, and 4) storage and regasification. The costs associated with each segment of this value chain must be less than or equal to the cost (on a per-unit-volume basis) of continental pipeline gas (including delivery charges) to make an LNG project attractive to investors. Recent technological improvements have reduced overall costs within the value chain; however, the magnitude of the total investment required to build and operate a new LNG terminal is in the $4 to $20 billion range.

A large cost component of the overall LNG value chain is the liquefaction facility, and the speculative building of complex and costly liquefaction facilities does not occur without long-term contracts to attract investors. Traditionally, these financial risks have been minimized by the execution of long-term "take-or-pay" supply contracts. However, with global markets affecting price volatility within all energy markets, current market players have been less than eager to enter into these types of long-term binding arrangements.

Short-term and spot-market contracts indexed to global natural gas and commodity markets have recently emerged. Spot-market LNG deliveries to the United States in 2004 represented nearly 70% of the total market, in contrast to 25% in 1998. The increase in spot-market LNG imports has created competition between the U.S. and Europe for valuable Atlantic Basin LNG cargoes. As a result of the current state of the global LNG trade, a worldwide lack of "uncontracted" liquefaction facilities is a prime bottleneck with respect to the development of new LNG import terminals.

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[88] The NGA Web site is located at http://www.northeastgas.org/pdf/lng_terminals_0106.pdf.

[89] The six LNG terminals are 1) Suez Energy North America's Everett LNG terminal in Everett, MA; 2) Dominion's Cove Point LNG in Lusby, MD; 3) El Paso Corp.'s Elba Island LNG terminal in Elba Island, GA; 4) Southern Union's Trunkline LNG terminal in Lake Charles, LA; 5) Excelerate Energy's Gulf Gateways Energy Bridge, offshore Louisiana, the newest North American LNG terminal; and 6) ConocoPhillips and Marathon's Kenai Peninsula LNG export facility.

LNG Shipping Issues: As of May 2005, approximately 183 LNG ships were in service, with new orders in the range of 50 to 150 ships. This could bring the potential fleet to over 300 ships by the end of 2009. As identified in several publications, one major issue that will constrain the expansion of the global LNG trade will be the lack of experienced and qualified staff for these new ships.[90] Some LNG industry analysts now project shortages of the following:

- Qualified mariners for new and incoming LNG tankers
- Time to educate and train new LNG officers
- Training facilities and qualified instructors
- Opportunities to exchange accumulated knowledge for the reliable expansion of the industry

Natural Gas Quality and LNG Interchangeability: As a result of the newly proposed LNG facilities around the coastline of North America, one issue currently being addressed concerns natural gas and LNG interchangeability. To avoid excluding potential LNG suppliers while simultaneously satisfying the safety concerns of their end-use customers, some interstate gas pipelines are seeking to revise their FERC gas-quality tariffs. Most of the LNG from around the world is considered "hot" with respect to heat content (MMBtu) and has a different makeup when compared with North American natural gas. Local gas distribution companies representing their end-use customers (residential, commercial, industrial, and power generation) are concerned about the safety and reliability impacts that this new fuel source may have on their customers' appliances, processes, and equipment. Several meetings have already taken place between pipeline companies and their customers to discuss these issues and address who will incur the financial costs if equipment upgrades are required. The ISO continues to monitor this gas interchangeability issue for potential impacts on gas-fired power plant availability and system reliability.

6.4.4 Long-Term Risk Mitigation—Adding Alternative Technologies

Since over 60% of the generation resources within the region are fueled by natural gas or oil or both, mitigating the long-term risks of increased energy costs and interrupted fuel supply is essential. The addition of new technologies adds to the mix of fuels used in New England. Renewable resources are also being used, some of which produce electricity without consuming any fossil fuels at all. New regional regulatory initiatives will likely foster the development of such new resources. Conservation and demand-side management improvements can also reduce the region's dependence on natural gas and oil supplies. Coupled with new rules and provisions for future electric energy markets, New England's generation portfolio is slated to move in a new direction.

6.4.4.1 Status of New Technologies for Increasing Fuel Diversity

The use of several types of additional fuels, including new coal technologies and renewable sources, such as wind energy and biomass, could increase fuel diversity in New England. This section summarizes some of the emerging technologies associated with using these fuels.

New Coal Technologies: New coal technologies consist of advanced pulverized coal plants, fluidized-bed combustion, and integrated coal-gasification combined cycle (IGCC). While the first two technologies provide improvements over conventional pulverized coal plants, the IGCC

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[90] U.S. Department of Homeland Security and U.S. Coast Guard, excerpts from *The Coast Guard Journal of Safety at Sea—Proceedings of the Marine Safety and Security Council*, fall 2005.

technology appears to have the most attractive performance characteristics and associated costs, as described below.

An IGCC plant is essentially a coal gasifier integrated with a conventional combined-cycle plant. As shown in Figure 6-3, coal enters a gasifier that in an atmosphere with reduced oxygen produces a synthesis gas or syngas of carbon monoxide (CO) and hydrogen (H_2), with slag as the waste product. This syngas then passes through a cleaning process that removes the impurities and captures carbon dioxide for potential use or sequestration. The H_2 is then burned in the combustion turbine. Gasification is widely used in the petrochemical industry, which operated over 385 gasifiers in 2004.[91] A number of IGCC plants have operated or are still operating worldwide, four of them in the United States.

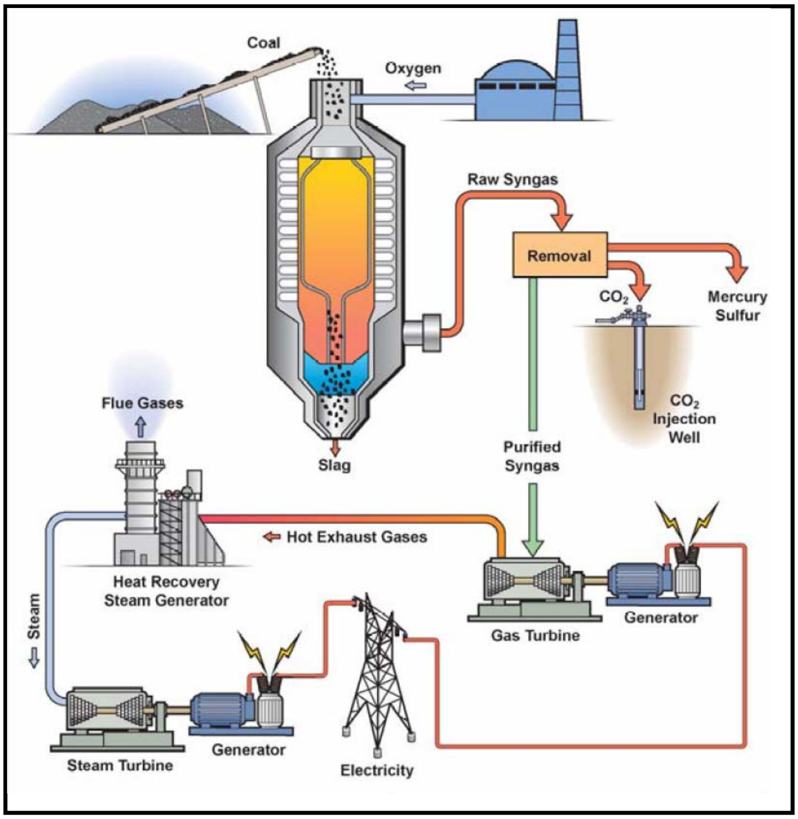

Figure 6-3: Conceptual diagram of an IGCC plant.

Source: Kopp Illustration

Several methods exist for sequestering carbon, all of which are challenging. These methods include the geological storage of CO_2, ocean storage, biological processes, and afforestation, which is a current practical option being conducted by many companies around the country. In 2003, the top

[91] U.S. DOE, National Energy Technology Laboratory, *Gasification World Survey Results 2004*, September 2005. See http://www.netl.doe.gov/publications/brochures/pdfs/Gasification_Brochure.pdf.

10 U.S. companies in this field sequestered about eight million tons of CO_2 mainly through forestry practices.[92]

IGCC has several advantages over conventional pulverized coal plants. Its environmental impact is significantly less than a conventional coal plant's with respect to air emissions, water use, and solid waste. When including the plant's costs of CO_2 control (carbon capture), total construction costs for IGCC plants and the costs for these plants to produce electricity are expected to be less.[93] Also, more of the plant can be shop-fabricated, offering construction flexibility, and multiple products can be produced besides electricity (e.g., H_2).

Three vendor teams, each including a gasifier developer and an architectural-engineering firm, are currently offering commercial IGCC plants: GE and Bechtel, Shell/Uhde and Black and Veatch, and Conoco-Phillips and Fluor. American Electric Power (AEP) is proposing to build two 600 MW IGCC plants, and CINERGY is proposing one with in-service dates of 2010 to 2012. One company has shown an interest in bringing IGCC technology to the region. Like existing coal plants in New England, IGCC would probably operate as a baseload unit.

Renewable Resources: The status of renewable technologies that would be most adaptable for the New England region, including wind, biomass, and several other technologies is as follows:

- ***Wind:*** Wind energy grew 37% in the U.S in 2005, and the size of commercially available wind turbines being built has increased to over 3 MW. Currently, New England has only two operational wind energy projects, which produced over 12 GWh of electric energy in 2005.

  Numerous new wind projects have been proposed for New England and are in various stages of development. As of June 4, 2006, 12 wind projects, totaling 924 MW, are in the ISO Generator Interconnection Queue (see Section 9.2).[94] While wind projects are economic relative to other energy options, like all larger power plants, these plants have siting issues.

- ***Biomass:*** New England gets significantly more electric energy from wood and biomass generating plants than wind projects. The *2006 CELT Report* shows the region having 915 MW of installed wood/biomass plants. These plants, in aggregate, contributed 6,739 GWh of electric energy in 2005. Most wood/biomass plants are stoker-type boiler systems that operate as baseload units. These units are challenged with respect to complying with emissions regulations and coordinating the transportation logistics for the numerous trucks delivering fuel. The ISO Generator Interconnection Queue shows three biomass/wood-waste plants (totaling 140.5 MW) proposed within New England.

  The state Renewable Portfolio Standards (RPS) (see below and Section 7) include wood/biomass plants as renewables resources, on the basis of vintage and whether they use sustainable fuels and advanced technology that reduces their overall environmental impact. Each plant's nitrogen oxides (NO_X) emission rate is also a criterion for being (or not being) approved as a renewable resource that can contribute to meeting the RPSs.

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[92] See http://www.treepower.org/EIA2004/main.html.

[93] Holt, N., "Gasification and IGCC—Design Issues and Opportunities," Slide 16 of the Electric Power Research Institute presentation at the Global Climate Change Energy Project (GCEP) Advanced Coal Workshop, Provo, Utah, March 15–16, 2005. See http://gcep.stanford.edu/pdfs/RxsY3908kaqwVPacX9DLcQ/holt_coal_mar05.pdf.

[94] A list of proposed generation and transmission projects that have requested to be interconnected to the New England Control Area is available at http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/status/.

- ***Other:*** Other renewable technologies include landfill gas, solar photovoltaic (PV), and fuel cells. Further development of LFG generation is possible, and one small project is proposed within the ISO Generator Interconnection Queue. Solar PV is also growing, with financial support from state clean energy fund incentives to reduce the relatively high capital costs of installing this technology. The region has many installations of PV technology, which typically is installed behind the meter, as tracked by the Massachusetts Distributed Generation (DG) Collaborative.[95] However, these amount to less that 1 MW.

  Fuel cells are also growing in use, with several new projects announced in New England. But they also require incentives to reduce their installation cost (greater than $4,000/kW). Worldwide, perhaps a total of 60 MW of stationary fuel cells are installed at customer sites. These usually are behind the meter and serve critical customer-based load requirements as well as provide heating, air conditioning, and ventilation.

Nuclear: The potential exists for New England's four operating nuclear plants to increase their contribution to the region's mix of fuels mainly through rating increases (uprates). The ISO's queue lists Millstone 2 as having completed a rating increase of 26 MW, while Pilgrim received one for 35 MW. Additionally, Seabrook, Millstone 3, and Vermont Yankee have submitted uprate requests to the Nuclear Regulatory Commission for a total of 260 MW.

Longer-range potential exists for increasing the use of nuclear energy through the development of improved advanced designs of nuclear plants, which is taking place through a collaborative effort by the Electric Power Research Institute (EPRI), the Nuclear Regulatory Commission (NRC), the U.S. Department of Energy (DOE), vendors, and others. A consortium of 12 members, called NuStart Energy, is seeking to demonstrate the feasibility of using a combined operating and construction license for building these new types of nuclear facilities.[96] Two sites in the South have been selected for this feasibility demonstration. As of June 30, 2006, no announcements have been made for actually building a new nuclear plant in the United States.

6.4.4.2 Role of New Regulations in Influencing Fuel Diversity

Directly or indirectly, a number of new state and regional regulations will encourage fuel diversity through incentives for installing new technology, although RSP06 did not analyze the economic affects of these regulations on existing generating units and customers.

Renewable Portfolio Standards: Five states in New England have RPSs, with New Hampshire being the lone exception. RPSs typically require load-serving entities to purchase a growing portion of their electric energy from certified renewable technologies. Connecticut recently enhanced its RPSs to allow combined heat and power (CHP) and energy efficiency as renewables (in its Class III category). CHP facilities, which produce both electricity and steam from a single fuel, save fuel by recovering

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[95] The Massachusetts Department of Telecommunications and Energy considers DG to be generation provided by relatively small installations directly connected to distribution facilities or retail customer facilities. These installations, which include those powered by renewable energy resources, alleviate or avoid transmission or distribution constraints or the installation of new transmission or distribution facilities. For example, small (2–4 kilowatt) solar photovoltaic systems installed by retail customers contribute to distributed generation. (MA DTE, DTE 02-38-B, *Investigation by the Department of Telecommunications and Energy on its Own Motion into Distributed Generation. Order on Joint Motion for Clarification,* December 13, 2004. See http://www.mass.gov/dte/electric/02-38/1213ordjm.pdf.)

[96] NuStart Energy members include Constellation Energy, Duke Energy, EDF International North America, Inc., Entergy Nuclear, Exelon Corp., FPL Group, Progress Energy, SCANA Corp., Southern Co., the Tennessee Valley Authority (TVA), GE Energy, and Westinghouse Electric Co. LLC.

the heat usually wasted in an electricity generator. CHP may supplement power-grid generation with more efficient on-site use of the same or similar fuel types.

Section 7.1 of this report more fully summarizes the RPS technologies and annual percentage requirements for each state. The intent of RPSs is to encourage the development of new renewable technologies. However, some existing supply-side resources have recently been certified as RPS compliant, potentially delaying the development of new renewable resources.

Regional Greenhouse Gas Initiative Requirements: The Regional Greenhouse Gas Initiative (RGGI) is a voluntary, seven-state commitment to mandate generating plants (25 MW or larger) in those states to cap their CO_2 emissions starting in 2009. The direct effect will be to encourage energy efficiency and the use of generators with lower CO_2 emissions to serve regional electric energy demands. These facilities include low- or zero-emitting supply-side resources, such as wind, biomass (considered CO_2 neutral), nuclear, and gas-fired combined cycle. While the latter technology has the lowest CO_2 emission rate of all fossil fuel plants, adding more power plants of this type would detract from, not enhance, fuel diversity in New England. IGCC plants could contribute to fuel-diversity goals if their CO_2 output were captured and sequestered. Any new coal plant without CO_2 capture would significantly contribute to the region's aggregate CO_2 emissions. Because nuclear facilities generate no air emissions, they can also contribute to meeting the region's growth in demand under a CO_2 emissions cap.

Massachusetts 310 CMR 7.29 CO_2 Regulations: Emission regulations in Massachusetts address limiting the amount of CO_2 emissions from six fossil fuel stations.[97] Starting in 2006, each facility has an annual CO_2 tonnage cap, generally based on the average CO_2 emissions from each facility for 1997 to 1999. Also, an annual CO_2 emissions-rate cap of 1,800 lb/MWh will take effect in 2008. A price-cap regulation allows the plants to purchase greenhouse gas (GHG) offsets from the nonelectric sector up to a capped price of $10 per ton.[98] The six plants are well below their tonnage caps, but a number of plants are above the emissions-rate cap. While these regulations are less severe than the RGGI caps, they will increase the overall operational energy costs of some plants with CO_2 rates above the 1,800 lb/MWh rate-cap limit.

State Regulatory Efforts to Enhance Fuel Diversity: The fourth type of regulation is the effort by states to enhance new local capacity and distributed generation. The *Connecticut Energy Independence Act* provides cost incentives to install new generation on the grid or distributed at customers' sites and promote energy-efficiency projects.[99] The Massachusetts Department of Telecommunications and Energy (MA DTE) is seeking to remove current hurdles to installing DG and has developed procedures to make applications for DG more streamlined for customer permitting.[100] From the second quarter of 2004 through the first quarter of 2005, about 70% of the applications made under this docket were for natural gas-fired distributed generators. It is unclear

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[97] Massachusetts Regulation 310 CMR 7.29 and 310 7.00 Appendix B as amended, *Final Greenhouse Gas Emission Implementation Amendments*, Final regulations were filed on September 15, 2006, and will be promulgated on October 6, 2006. See http://www.mass.gov/dep/public/press/0906ghg.htm.

[98] *Offsets* are reductions in greenhouse gas emissions in certain nonelectric sectors, including reductions in landfill gas emissions and sulfur hexafluoride (SF_6) leaks, gas end-use efficiency savings, and afforestation.

[99] Connecticut Public Act 05-01 (House Bill No. 7501), (June Special Session), *An Act Concerning Energy Independence*.

[100] See MA DTE Docket 2-38B, available at http://www.mass.gov/dte/electric/02-38/224order.pdf. MA DTE can be accessed at http://www.mass.gov/dte/index.htm.

whether this incentive for DG interconnections enhances or detracts from regional fuel diversity. Given the small total size (less than 13 MW) of these applications, this increase in natural gas use is not likely significant. Taken as a whole, these new regulations may, over time, be a positive force to encourage fuel diversity.

6.4.4.3 Market for Increasing Fuel Diversity

Enhancing fuel diversity is a solution to two distinct but related problems. One problem relates to short-term fuel security (i.e., natural gas supply concerns raised by the January 2004 Cold Snap). The second problem relates to the long-term availability and price of strategic fuels. Since New England electricity prices are highly dependent on natural gas prices, any significant reduction in the availability of natural gas could have profound consequences for New England. Each of these concerns can be addressed by the provision of market incentives, as described below, which will result in increased availability of existing units and investment in new alternative resources.

Potential Revenue Streams of Alternative Generation Resources: Investments in electricity production facilities based on specific fuel sources are influenced by many market and regulatory incentives. These incentives directly influence the region's fuel diversity. Some are external to the ISO, such as RPSs, which, on a regional level, increase the percentages of renewable power bought and sold through the marketplace and make the output from renewable resources more valuable. RGGI, also external to the ISO, is likely to make the production of electricity from carbon-emitting resources more expensive. On a national level, the *Energy Policy Act of 2005* (EPAct) provides financial incentives to encourage the development of nuclear power as well as promote new coal technologies, such as IGCC.[101]

The ISO does not subsidize or penalize producers for using any particular fuel types. Rather, the ISO, both in its current markets and in its proposed market enhancements, provides economic incentives to generation that produces electricity when it is most valuable to the region. These incentives arise naturally in the energy market. As demand increases, prices rise, giving suppliers strong financial incentives to produce electricity when it is needed most. One way to ensure this production is for a supplier to own a diverse portfolio of assets powered by different fuel sources. This would reduce the supplier's risk that it will not be able to produce electricity if the fuel supply were disrupted.

New Market Improvements that Benefit Fuel Diversity and Reliability: Today, a great deal of concern exists about high wholesale electricity prices, driven largely by high oil and natural gas prices. New England can be viewed as especially vulnerable to high oil and natural gas prices because of the region's overdependence on natural gas and a lack of fuel diversity. Currently, the markets are sending strong signals to invest in non-gas-fired generation. With the recent gas-price-induced increase in wholesale electricity prices, alternative generation resources have become more profitable, which increases incentives to invest in alternative sources of generation. A resource owner will be able to reduce its fuel-supply disruption risk by investing in a diverse portfolio of assets and being capable of producing electricity during periods of tight capacity and high prices.

By modifying the existing markets and developing new market rules and procedures, the groundwork has been laid to resolve some of the short-term, seasonal, fuel-supply concerns. The ISO has addressed several market issues with the implementation of ASM I (in October 2005) and ASM II, scheduled for implementation in the fourth quarter of 2006. ASM I targeted improvements to the

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[101] *Energy Policy Act of 2005*, Pub. L. No.109-58, Title XII, Subtitle B, 119 Stat. 594 (2005) (amending the *Federal Power Act*).

Regulation Market, with respect to the price of service, opportunity costs, and mileage payments.[102] The Real-Time Energy Market benefited from new market rules regarding fuel-price flexibility to manage or reflect volatile fuel costs. Also, external purchases are now able to set LMPs. ASM II will bring a locational requirement to the Forward Reserve Market, and demand-responses resources will be able to participate in the Day-Ahead Energy Market.

These incentives will be strengthened with the introduction of the performance incentives contained in the proposed Forward Capacity Market, now under development and scheduled to begin in the 2010 timeframe (see Section 4.1.3). The FCM, which is intended to provide net benefits to both generation and load, should encourage stakeholders to make more long-term financial commitments. One proposed feature of the FCM is to roll back the electricity market timelines for each December through February period, so that the results of the Day Ahead Energy Market and Resource Adequacy Assessment (RAA) are available by 10:30 a.m. on the day before the operating day.[103] This will inform gas-fired generators of their electricity market commitments so that they can procure and nominate gas in the first (timely) cycle. This shifting of deadlines should lead to the improved synchronization of the electricity and gas markets. In addition, performance metrics have been proposed to encourage fuel-procurement strategies that support increased unit availability during times of need. These incentives should translate into additional contracting for firm gas and dual-fuel operability or a combination of both benefits.

Another strategy to increase fuel diversity in the region is to import electricity generated by diverse fuels via long-term firm contracting with neighboring regions. In general, the greater NPCC footprint has a well-balanced fuel-supply portfolio. However, until the longer-term remedial activities inherent to the implementation of the FCM mature, the ISO will continue to manage short-term, seasonal fuel-diversity issues as required.

6.5 Summary of Key Findings

Some of the key messages and observations related to New England's fuel-diversity issues and short-, near-, and long-term activities to address these issues are summarized below.

- **Seasonal Availability and Reliability—**To assure the short-term seasonal availability of fuels and winter-peak reliability, New England's generators must bolster their ability to procure firm fuel supplies and delivery and manage potential natural gas and oil shortfalls during periods of extreme weather or other abnormal conditions. Participants can promote fuel diversity and system reliability by using existing electricity, oil, and natural gas infrastructure more efficiently. An essential long-term strategy to enhance seasonal availability is to expand the regional natural gas supply and delivery infrastructure, especially for LNG.
- **Dual-Fuel Capability—**In the near term, converting oil- or gas-fired generators into dual-fuel capable units should increase unit availability. Converting gas-only units that already hold air permits that allow for dual-fuel operation is the first priority. The ISO and regional stakeholders can review and modify, if needed, existing operating procedures and market rules to ensure that they encourage investment in expanding or adding sustainable dual-fuel capability and reliability-based fuel-procurement strategies (i.e., firm supply/delivery

[102] FERC Order ER05-795-001 can be accessed at http://www.iso-ne.com/regulatory/ferc/orders/2005/jun/ER05-795-000_6-6-05.doc.

[103] Refer to AMR05 for further details on this feature of the FCM and the RAA.

mechanisms).

- **Use of Alternative Resources—**For the near and long terms, the ISO and regional stakeholders, including state regulators and siting councils, must begin planning for the use of alternative resources to diversify the current mix of fuels. They can ensure market incentives exist to attract alternative energy sources and make “clean” baseload units commercially available. They can also promote the research and development of other technologies. Wind power, nuclear, new coal technologies, and additional Canadian imports of electricity must all be considered if New England is to move toward a more diversified fuel-supply portfolio. Because the wholesale price of electricity is representative of the true marginal cost of fuel, adding resources other than those fired by natural gas or oil generally can reduce risk in a supplier’s portfolio.
- **Compliance with Environmental Regulations—**Regional stakeholders must continue to work diligently to balance the need for environmental stewardship with the need to provide bulk power system reliability. They must make every attempt to meet the states’ Renewable Portfolio Standards and continue to monitor the proposed policies and regulatory framework of RGGI as it affects regional fuel diversity.
- **Asset Diversity—**The region is exposed to price volatility because of an overdependence on natural gas and oil to generate electricity. Suppliers that invest in a diverse portfolio of assets reduce the risk of not being able to produce electricity during periods of tight capacity and high prices. Having a diverse portfolio of resources also ensures that suppliers would be able to produce electricity during fuel-supply disruptions.

Section 7
Environmental Requirements Influencing New Resources

Many New England states require some percentage of the annual total electricity used within their borders to be fueled by renewable sources of energy. These requirements not only enhance fuel diversity, as discussed in Section 6, but also provide environmental benefits. Other environmental requirements in the region call for power plants to limit their CO_2 emissions, which will likely influence the type of investment in new regional facilities. This section discusses the environmental requirements influencing the need for "clean" new resources to generate electricity in New England. In addition to discussing Renewable Portfolio Standards and the Regional Greenhouse Gas Initiative (in more detail than Section 6), the section provides information on several other federal and state air regulations that aim to reduce power plant emissions of sulfur dioxide (SO_2), NO_X, and mercury.

7.1 Renewable Portfolio Standards

This section discusses the status and outlook for meeting Renewable Portfolio Standards in Maine, Massachusetts, and Connecticut, which currently have such standards in effect, and in Rhode Island, which will have RPSs in effect in 2007. Vermont is implementing regulations for its RPSs that became law in that state in 2005.

Load-serving entities in these states will need to provide an increasing amount of electricity from designated renewable technologies. Other ways for load-serving entities to meet the RPS requirements include buying Renewable Energy Certificates (RECs) from projects outside New England or paying an Alternative Compliance Payment (ACP) for any shortfall, which will fund future renewable projects.

7.1.1 Status of Meeting Renewable Portfolio Standards

Table 7-1 shows the RPS requirements for the individual New England states. The table lists the requirements for the specific renewable technologies permitted and the annual percentage of electric energy consumption that must be supplied by renewable resources.

Table 7-1
Summary of State Requirements for Renewable Portfolio Standards and Renewable Technologies Allowed

Technology	Connecticut Classes			Massachusetts	Maine	Rhode Island	Vermont
	I	II	III				
Solar thermal	✓	✓		✓	✓	✓	
Photovoltaic	✓	✓		✓	✓	✓	
Ocean thermal	✓	✓		✓	✓	✓	
Wave	✓	✓		✓	✓	✓	
Tidal	✓	✓		✓	✓	✓	
Wind	✓	✓		✓	✓	✓	✓
Biomass	Sustainable, low emission	✓		Low-emission, technology	✓	✓	✓
Hydro	< 5 MW	< 5 MW			✓	< 30 MW	< 80 MW
Landfill gas	✓			✓	✓		✓
Sewage plant waste							✓
Fuel cells	✓			w/ renewable fuels	✓	w/ renewable fuels	
Geothermal					✓	✓	
MSW		✓			w/ recycling		
Cogeneration, combined heat and power			✓[a]		✓		
Energy efficiency			✓				
Percent Requirement							
Year	**I**	**II or I**	**III**		[b]	[c]	
2006	2.0			2.5		-	
2007	3.5		1	3.0		3	
2008	5.0		2	3.5		3.5	
2009	6.0		3	4.0		4.0	
2010	7.0	3% in all years	4	5.0	30% in all years	4.5	Incremental growth from 2005 for all years
2011	7.0		4	6.0		5.5	
2012	7.0		4	7.0		6.5	
2013	7.0		4	8.0		7.5	
2014	7.0		4	9.0		8.5	
2015	7.0		4	10.0		10	
Use Generator Information System (GIS) renewable energy certificates?	Yes			Yes	Yes	Yes	Yes
Renewable energy certificates outside ISO New England	New York only until 2010			w/ deliverability		w/ deliverability	w/ deliverability

(a) CHP facilities can be used to offset generation on the grid with more efficient on-site use of fuel.
(b) By 2017, Maine must increase its share of renewable resources by 10% of the total capacity resources in that state as of December 31, 2007.
(c) Existing resources can make up no more than 2.0% of the total.

Connecticut had a requirement in 2004 that 1% of an LSE's electricity must be from Class I renewables, and, similarly, 3% must be from Class II sources. Connecticut recently enhanced its RPSs to include CHP and energy-efficiency projects in a Class III category. All the Connecticut LSEs met their required percentages in 2004, mostly by purchasing electricity generated by landfill gas (74.6%) for Class I and trash-to-energy sources (75.6%) for Class II.[104]

In 2004, Massachusetts, with only one RPS class, required 1.5% of the electricity generated by LSEs to be fueled by renewable resources. The LSEs met 60% of this requirement from generation. The LSEs also used the previous year's banked compliance credits and made an Alternative Compliance Payment of $13.6 million total for the other 35% of their requirement. Of the electricity generated by renewable sources, 84% was from New England projects, and 14% was from New York projects through the purchase of RECs. Landfill gas provided 60% of the RPS electricity generated in Massachusetts in 2004, and biomass plants provided 35%.[105]

Maine's requirement is for LSEs to provide 30% of the state's electricity from renewable sources, which the state has easily met since 2000. Maine recently revised its renewable resource requirement so that by 2017 the state must increase its share of renewable resources by 10% of the total capacity resources in that state as of December 31, 2007.[106] On the basis of 2006 capacity, this would require the state to increase the amount of electric energy generated by renewable fuel sources by about 260 MW.

7.1.2 Outlook for Meeting Renewable Portfolio Standards by 2010 and 2015

Table 7-2 projects the RPS electricity requirements for 2006, 2010, and 2015, on the basis of the ISO's 2006 forecasts for annual electric energy use by state and the RPS percentage requirements shown in Table 7-1. Table 7-3 shows the total RPS requirement for the four states (for 2006, 2010, and 2015) as a percent of the projected total of the electric energy use in New England.

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104 State of Connecticut Department of Utility Control, *DPUC Review of Renewable Portfolio Standards for Compliance for 2004. Draft Decision,* Docket No. 05-11-01, March 2, 2006.

105 Commonwealth of Massachusetts, Division of Energy Resources, *Annual RPS Compliance Report for 2004,* January 9, 2006.

106 Maine's renewable resource requirements are contained in *An Act to Enhance Maine's Energy Independence and Security*. See http://www.mainelegislature.org/legis/bills/LD.asp?LD=2041.

Table 7-2
Projected State RPS Requirements Based on the ISO 2006 Electric Energy Use Forecast (1,000 MWh)

State	2005	2006	2010	2015
Connecticut (Class I)[(a)]	493	660	2,428	2,617
Massachusetts	1,042	1,322	2,693	5,770
Rhode Island		0	405	925
Vermont		0	225	535
Total RPS requirements	**1,535**	**1,982**	**5,751**	**9,847**
Increase above 2005 requirements[(b)]		**447**	**4,216**	**8,312**

(a) The Connecticut Class II percent does not increase, and a new Connecticut Class III is not truly renewable. Therefore, these two classes are not included in the table.

(b) It was assumed that facilities in these states used existing renewable projects to meet the 2005 requirements.

Table 7-3
Projected Total RPS Requirements Based on the ISO 2006 Electric Energy Use Forecast

	2006	2010	2015
Projected electric energy use (1,000 MWh)	135,000	140,330	151,085
Total RPS as percent of New England electric energy use	1.1	4.1	6.5

Table 7-4 shows estimates of the electricity that the proposed renewable projects in the ISO's Generator Interconnection Queue (as of June 4, 2006) could provide per year on the basis of the typical assumed capacity factors for each project and assuming all projects were built as proposed. The ISO recognizes that the resources capable of meeting the RPS requirements are based on the certification of the resources within each state.[107] The ISO has estimated the potential for the proposed renewables in the queue to meet the growth in RPSs, assuming that the existing state-certified renewable projects will continue to meet current requirements and that the future growth in renewable resources will most likely come from grid-connected renewable projects in the ISO queue.

[107] These state-certified projects include generators connected to the grid, generators behind the meter, and generators in adjacent control areas.

Table 7-4
New England Renewable Energy Projects in the ISO Queue

Type (#) of Projects[(a)]	Size (MW)	Assumed Capacity Factor (%)	Estimated Annual Electricity Production (1,000 MWh)
Hydro (1)	8	25	18
Landfill gas (1)	7	70	43
Biomass (3)	141	70	865
Wind onshore (11)	462	25	1,011
Wind offshore (1)	462	38	1,538
Total (18)	**1,027**		**3,475**

(a) A list of proposed generation and transmission projects that have requested to be interconnected to the New England Control Area is available at http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/status/index.html.

Compared to the requirements for 2010, as shown in Table 7-2, the renewable projects in the queue would be deficient in meeting the RPS requirements by about 700 GWh (700,000 MWh). In 2015, the electricity generated by these projects would be deficient by about 4,800 GWh (4,800,000 MWh) in meeting that year's RPS requirements for the four states with RPSs. About 800 MW would be needed if this electric energy were supplied by a baseload project with a 70% capacity factor. Alternatively, onshore wind projects totaling about 2,900 MW with a 25% capacity factor would be needed.

Given the region's past experience with the attrition of projects in the queue, the projections in Figure 9-1 are most likely optimistic. Thus, the shortfall may be even greater than that shown by the comparison of Table 7-3 and Table 7-4, unless new renewable projects are proposed. In any case, the renewable projects help meet the new capacity requirements cited in Section 4 and Section 5.

To meet their RPS requirements, Massachusetts and Connecticut have been certifying existing renewable generators and, in some cases, requiring technology upgrades. These existing certified renewable generators will likely continue to provide compliance for the LSEs. However, they probably will not be able to meet the increased need for electricity or growth in RPS requirements, making new renewable projects in the region critical.

In summary, by 2015 the region will need significantly more renewable projects than those currently in the ISO's generator queue to meet the projected growth in the RPS requirements of Connecticut, Massachusetts, Rhode Island, and Vermont.

7.2 Emission Projections and Future Regulations

The ISO has developed a base projection of the SO_2, NO_X, and CO_2 emissions from New England generators on the basis of existing regulations.[108] This serves as a basis to examine the effects of

[108] The report of the emission projections and sensitivity analysis is available at http://www.iso-ne.com/trans/sys_studies/rsp_docs/rpts/2006/final_rsp06_air_emissions.pdf .

planning and implementing federal and state regulations in New England over the 10-year planning period. These new regulations will increase expenditures for fossil fuel generators, which may affect the operation and future reliability of these facilities in the market.

Two sets of regulations would limit CO_2 emissions from power plants. These are the Regional Greenhouse Gas Initiative and the Massachusetts 310 CMR 7.00 Appendix B and 310 CMR 7.29 regulations.

7.2.1 Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative is a seven-state commitment to cap CO_2 emissions from generating units (25 MW or larger) in those states starting in 2009.[109] The governors of the seven states, which include Maine, New Hampshire, Vermont, and Connecticut, signed a RGGI Memorandum of Understanding (MOU) on December 20, 2005.

7.2.1.1 Terms of the Memorandum of Understanding

The MOU is an agreement to stabilize CO_2 emissions from the affected generators at current levels from 2009 through 2014. This would be followed by a gradual reduction in emissions reaching 10% by 2019. Regional emissions from all of the MOU states would be capped at 121.3 million tons of CO_2 during the stabilization period. The total cap has been distributed among the seven RGGI states in accordance with Table 7-5. The cap for the four New England states is 26.5 million tons. If Massachusetts and Rhode Island were to join RGGI, the total nine-state RGGI cap would be 150.6 million tons.

Table 7-5
CO_2 Emission Budgets for RGGI States

State	Annual CO_2 Budget (short tons)
Connecticut	10,695,036
New Hampshire	8,620,460
Vermont	1,225,830
Maine	5,948,902
New York	64,310,805
New Jersey	22,892,730
Delaware	7,559,787
Seven-state total	**121,253,550**
Massachusetts	**26,660,204**
Rhode Island	**2,659,239**
Nine-state total	**150,572,993**

[109] Maryland recently passed legislation that requires that state to join RGGI in 2007 after completing an evaluation of RGGI's impacts.

Each state's CO_2 allowance budget will automatically decline by 2.5% per year from 2015 through 2018. Each state may allocate allowances from its CO_2 emissions budgets as it determines appropriate. All states have agreed to set aside a minimum of 25% of their allowances for consumer benefit, strategic energy purposes, or both. States may create allowance set-asides for new generators. The generators will be able to use offsets for up to 3.3% of their emissions obligations over their three-year compliance period. If CO_2 allowance prices rise above certain trigger prices, they will be able to use a higher percentage of offsets. Banking of allowances adds flexibility.

7.2.1.2 RGGI Model Rule

On March 23, 2006, the RGGI Staff Working Group released a draft *Model Rule* for public comment.[110] The final rule, issued August 15, 2006, will form the basis for individual states to implement the program through regulations or legislation. The aim of RGGI is to encourage the development and use of lower-emitting CO_2 resources to serve the region's electricity needs starting in 2009 and stay under the regional cap.

7.2.1.3 Evaluation of RGGI's Potential Impacts on the New England Bulk Electric Power System

How RGGI will evolve is still largely uncertain. Some uncertainties are as follows:

- States' implementation of the final *Model Rule*—CO_2 allowance allocations, set-asides, penalties, and other regulatory provisions
- Whether a scarcity of allowances would limit the operation of generators[111]
- Treatment of CO_2 "leakage"[112]
- Potential for states to join or drop out of RGGI
- Possibility of a federal greenhouse gas cap-and-trade program being established that would supersede RGGI[113]
- The interaction of RGGI with other cap-and-trade programs in the United States

Notwithstanding these uncertainties, the ISO has assessed the draft *Model Rule* and evaluated the potential impacts that the RGGI cap might have on the region's affected electricity generators for varying CO_2 allowance prices and adding alternative resources.[114]

Figure 7-1 shows the CO_2 emissions from the affected RGGI units for the existing system without any capacity additions, on the basis of RSP06 base-case assumptions, including those for imports. The figure shows that higher allowance prices reduce the emissions from the RGGI generators in New England so they would be under the New England RGGI cap. At the same time, however, the

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[110] The ISO's comments on the draft *Model Rule* can be accessed at http://www.rggi.org/stakeholder_comments_model_rule.htm.

[111] Any scarcity of allowances could restrict the operation of generators, since no economical CO_2 emission control technologies exist to alternatively reduce CO_2 emissions.

[112] Carbon dioxide *leakage* refers to increased CO_2 emissions from electric energy generated outside the RGGI region and imported to the region, offsetting, in part, the reduced CO_2 emissions by generators within the RGGI states.

[113] RGGI modeling showed that a federal cap covering the U.S. would result in higher CO_2 allowance prices.

[114] See the ISO's *Regional Greenhouse Gas Initiative Impacts on the New England Power System*, 2006, available at http://www.iso-ne.com/genrtion_resrcs/reports/emission/index.html.

emissions from New England's non-RGGI generators (mainly located in Massachusetts and Rhode Island) increase. This increase in CO_2 emissions, as well as any similar CO_2 increase from Canadian imports resulting from the RGGI cap, is regarded as leakage. A RGGI working group is evaluating options to control or limit leakage before the cap is implemented.

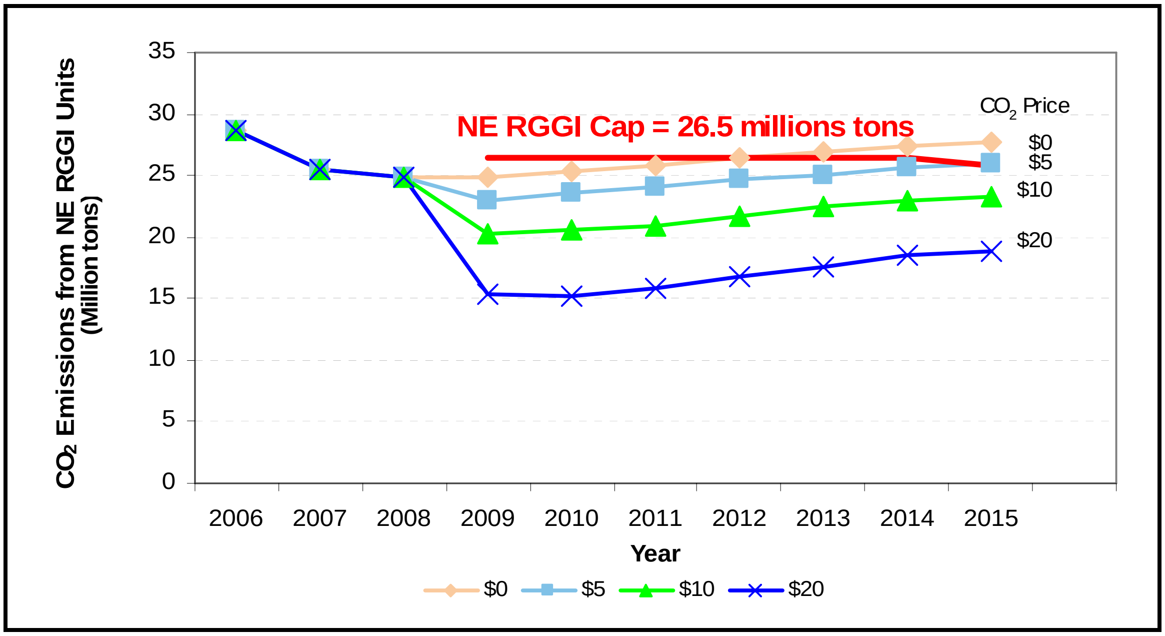

Figure 7-1: Annual CO_2 emissions from New England RGGI generators compared with CO_2 allowance price.

The ISO also considered the impacts of adding new resources to satisfy the growth in demand over the planning period on meeting the CO_2 cap. Cases were run assuming the addition of 1,000 MW of zero- or low-emitting resources in RGGI states, 500 MW in 2012, and another 500 MW in 2015. Alternatively, a QUEUE resource case was simulated that represented a 1,651 MW portfolio of projects in the ISO queue.[115] These cases, as follows, used the RSP06 base assumptions as the starting point:

- Base case for RSP06—no capacity added (BASE)
- Adding 1,000 MW of nuclear capacity (NUC)
- Adding 1,000 MW of IGCC capacity with no CO_2 capture and sequestration (IGCC0)
- Adding 1,000 MW of IGCC capacity with 90% CO_2 capture and sequestration (plant's net CO_2 emissions would be 10% of the no-capture case) (IGCC90)
- Adding 1,000 MW of natural gas combined cycle (NGCC)
- Adding a representative portfolio of resources from the ISO queue (1,651 MW) (QUEUE)

[115] The 1,651 MW of projects included the following: nuclear, 170 MW; wind, 497 MW; landfill gas, 15 MW; and natural gas/oil, 789 MW.

The cases also assumed that the owners/operators of the new capacity added could obtain the needed allowances from the states' allowance set-asides for new generators or from the allowances or offsets markets. Challenges in siting or licensing these resources were not considered. Figure 7-2 shows the results of these cases.

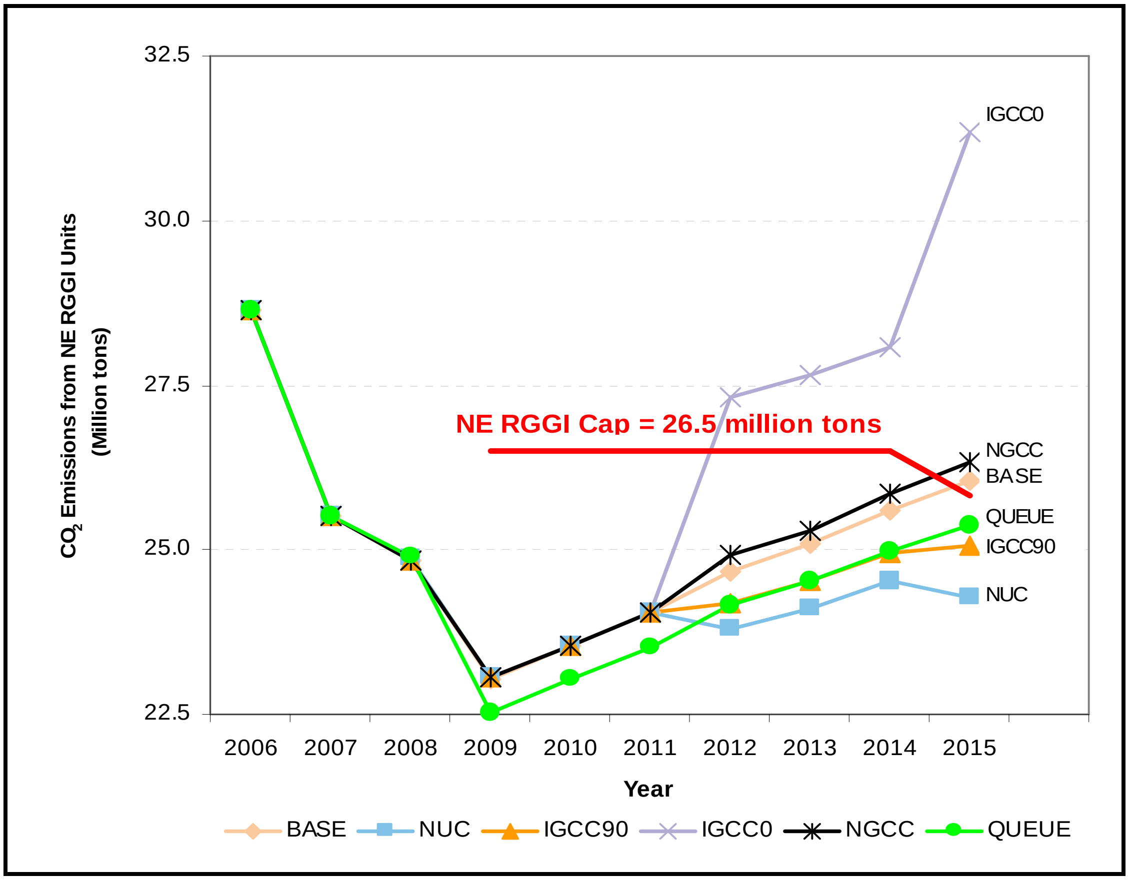

Figure 7-2: Impact of various new resource scenarios on meeting the New England RGGI CO_2 emissions cap for a CO_2 allowance price of $5 per ton.

The figure shows that, except for the IGCC case with no CO_2 capture and sequestration and the NGCC case for 2015, all of the cases with added capacity would allow the RGGI units to meet the cap through 2015, leakage notwithstanding. The case adding the portfolio of resources from the ISO queue (QUEUE) produces less CO_2 emissions than the case adding all new natural gas combined-cycle units (NGCC). This is because about 40% of the capacity in the QUEUE case would be generated by resources that have no CO_2 emissions (i.e., nuclear and wind projects). The NUCLEAR case provides the most reduction in CO_2 emissions by 2015—about 1.8 million tons from the RGGI generators and about 8 million tons from all New England generators.

The figure shows the importance of adding resources that have zero or low rates of CO_2 emissions per megawatt-hour to meet electric energy growth and the RGGI cap. This is especially so in the later years of the study, when the cap will be declining even more. By 2019, when the cap will be 10% lower at 23.9 million tons, no case will be below the cap.

Another result from the ISO analysis is that a RGGI cap affects the use of natural gas by less than 0.5%. This is because in the BASE case (no additions), the use of natural gas increases 35% over the 10-year planning period, as the plants that burn natural gas are the marginal units that increase their operation to meet the system's growth in electricity use. In the case of adding NGCC, gas use increases to 37% over the planning period, since these units are more efficient and offset some electric energy generated by existing oil units.

The analysis also shows that if Massachusetts and Rhode Island were to join RGGI, the generators affected by a cap in the six states (55.8 million tons), would not be able to meet the cap in the latter part of the 10-year planning period even with higher allowance prices (i.e., $20/ton). Problems would arise as early as 2010, even with the allowance price as low as $5 per ton.

These results, as well as the results of other cases examined, are described in more detail in the ISO report, *Regional Greenhouse Gas Initiative Impacts on the New England Power System*.[116]

An ISO consultant surveyed selected generators as to their likely RGGI compliance strategies. The responses showed that most would comply with the use of CO_2 allowances (allocated and auctioned) and risk management tools. Dual-fuel units may shift to using more gas. Some units might reduce or curtail their operation if allowance prices rose too high or their allowance costs could not be fully recovered through their existing bilateral contracts. The generators most at risk of not being able to continue operations under a RGGI CO_2 cap are those already financially marginal and facing compliance costs from RGGI in addition to other environmental regulations to be implemented over the next 10 years (see Section 7.2.3, below).

7.2.2 Massachusetts CO_2 Emissions Regulations

In 2001, Massachusetts issued regulations that cap the CO_2 emissions in tons from six older fossil fuel plants in the state (comprising 15 generating units) starting in 2006.[117] These regulations also cap the CO_2 emissions rate of these plants at 1,800 lb/MWh starting in 2008. The six plants are well below the tonnage cap, but most are above the emissions rate cap. To comply with both caps, the regulations allow the plants to purchase greenhouse gas offsets from the nonelectric sector up to a ceiling price of $10 per ton. While these regulations are less severe than the RGGI cap, they will increase the operating costs of the plants with CO_2 emission rates above the 1,800 lb/MWh limit.

The ISO's RGGI evaluation projects that the six Massachusetts plants affected by this regulation will stay under their cap of 27.8 million tons, but that 10 of the 15 units will exceed the emissions rate cap. To reflect this exceedance, the ISO evaluation for the RGGI cap also modeled the cost of offsets (the $10/ton price cap set in RGGI) needed for the Massachusetts 7.29 units to comply with the 1,800 lb/MWh rates. These dispatch cost adders were significantly less than the CO_2 costs for RGGI units. This made these units and the other units in Massachusetts and Rhode Island more economic to operate compared with RGGI units. These units would increase (leak) emissions, while the generators in the RGGI states would be affected by the RGGI cap.

[116] *Regional Greenhouse Gas Initiative Impacts on the New England Power System*, 2006, is available at http://www.iso-ne.com/genrtion_resrcs/reports/emission/index.html.

[117] These six plants are Brayton Point, Canal, Mt. Tom, Mystic, Salem Harbor, and Somerset.

7.2.3 Other Regulations Affecting Existing and New Generation

Other federal environmental regulations will have an impact on operating fossil fuel generators in New England and the associated costs of doing so during the planning period. The principal regulations include U.S. Environmental Protection Agency's (EPA's) *Clean Air Interstate Rule* (CAIR), *Clean Air Mercury Rule* (CAMR), and Regional Haze Program.[118] Together, these rules create a multi-pollutant strategy to reduce SO_2, NO_X, and mercury (from coal plants only) in stages through 2018. These reductions are needed to help meet the ozone standards over a 28-state region, essentially east of the Mississippi River, and reduce the mercury released into the environment. Massachusetts and Connecticut will implement state regulations in the next few years, which will require fossil fuel plants to reduce SO_2 and NO_X emissions.[119]

7.2.4 Cumulative Impacts of Compliance with Environmental Regulations

Compliance with these environmental regulations will reduce regional emissions but will also cumulatively increase the operating costs of the region's existing fossil fuel generators. Although the ISO cannot predict these costs, it is assessing the impacts that compliance could have on system operations and system reliability, such as to cause some financially marginal units to deactivate or retire. The ISO has no way of speculating about the effect of these regulations on individual generators; generator owners and operators will determine how they will comply with these regulations and address their increased operating costs.

Conservation can be a useful strategy for environmental compliance. In this case, the ISO's analyses of marginal emission rates show how reducing load and the amount of electric energy used in New England reduce emission rates.[120]

7.3 Summary of Key Findings

The renewable resource projects in the ISO queue appear to be insufficient to meet New England's RPS requirements over the planning period. Significant additional renewable projects are needed in the region during 2010 to 2015 to meet the RPS.

Generators in the region will need to comply with a RGGI CO_2 emissions cap and other new environmental regulations to be implemented over the next 10 years, which will impose additional capital costs, operating costs, or both. As a result, generators that are already financially marginal may be more at risk of deactivating or retiring from the system.

An ISO system analysis shows that the RGGI generators affected by the cap could meet the cap by 2015 at modest CO_2 allowance prices (simulated as $5/ton). However, to stay below the cap, resource additions with zero or low CO_2 emissions would be needed to serve electric energy growth in the RGGI states, especially after 2014 when the RGGI cap will be reduced. If Massachusetts and Rhode Island joined RGGI, zero- or low-CO_2 emitting resources could be required as early as 2010 to meet the cap, depending on allowance prices. The six plants affected by the Massachusetts 7.29 regulations

[118] The Regional Haze Program requires the improvement of visibility in 156 national parks and wilderness areas. See http://www.epa.gov/air/visibility/program.html.

[119] 310 CMR 7.29, *Emission Standards for Power Plants*, May 2004, and Connecticut Executive Order 19, implemented in Regulations of Connecticut State Agencies (RCSA) 22a-174-19a and 22a-174-22 (May 17, 2000).

[120] See http://www.iso-ne.com/genrtion_resrcs/reports/emission/index.html for more information on the ISO's *Marginal Emissions Rate Analyses.*

appear able to meet their tonnage caps, but some will need to purchase offsets to meet the 1,800 lb/MWh rate caps.

Section 8
Transmission Security and Upgrades

The bulk power system functions as a whole, with its components interacting in many varied and complex ways often in a tight balance. A poorly designed system change can affect this balance, from providing a negligible benefit to causing significant negative effects. Thus, all proposed system modifications, including transmission and generation additions or significant load reductions, must be carefully analyzed.

Much progress has been made over the past few years in analyzing the transmission system and developing solutions to address existing and projected inadequacies. From 2002 to June 2006, 127 projects have been placed in service for a total of $429 million in construction costs.[121] Five major 345 kV projects are in various stages of development in the region, with state siting approval either completed or underway. Two of these projects are expected to be placed in service by the end of 2006.

Section 8 discusses the basis for transmission security and the performance of the transmission system in New England. It addresses the need for transmission upgrades, including improvements to load and generation pockets, on the basis of known plans for the addition of resources. It also provides an update on the progress of the current major transmission projects in the region. Information regarding the detailed analyses associated with many of these efforts can be found in RSP05 and prior regional plans.[122]

8.1 Basis for Transmission Security

Conformance with the criteria used to assess transmission security and ensure that area transmission requirements are met provides for a robust system that serves a number of purposes. These purposes are as follows:[123]

- Provide for the secure dispatch and operation of generation
- Deliver numerous products and services:
    - Capacity
    - Electric energy
    - Operating reserves
    - Load-following
    - Automatic generation control
    - Immediate contingency response for sudden generator or transmission outage

Transmission systems also assist in the following tasks:

[121] The RSP06 *Transmission Projects Listing, July 2006 Update*, can be accessed at http://www.iso-ne.com/trans/sys_studies/rsp_docs/pres/indx.html.

[122] RSP05 can be accessed at http://www.iso-ne.com/trans/rsp/2005/index.html.

[123] Refer to the ISO's planning procedures, located at http://www.iso-ne.com/rules_proceds/isone_plan/index.html, for more information on the criteria for the transmission system.

- Improve the reliability of and access to supply resources
- Regulate voltage and minimize voltage fluctuations
- Stabilize the grid after transient impacts
- Use existing regional resources efficiently
- Reduce reserves required for the secure operation of the system
- Facilitate the scheduling of equipment maintenance

8.2 Transmission System Performance and Needs

The New England bulk power system serves a diverse region, which ranges from rural to dense urban, integrating widely dispersed and varied types of power supply resources to meet demand. The geographic distribution of New England's summer- and winter-peak loads is approximately 20% in the northern states, Maine, New Hampshire, and Vermont, and 80% in the southern states, Massachusetts, Connecticut, and Rhode Island. Although the northern land area is larger than the southern area, the greater development and power supply concentration in the south creates the relatively larger southern load and consequent transmission density.

The New England bulk transmission system comprises mostly 115 kV, 230 kV, and 345 kV circuits with transmission lines in the north generally longer and fewer in number than in the south. The New England area has nine interconnections with New York: two 345 kV ties, one 230 kV tie, one 138 kV tie, three 115 kV ties, one 69 kV tie, and one 330 MW HVdc tie.

Currently, New England and New Brunswick are connected through one 345 kV tie, with a second 345 kV tie planned.[124] New England also has two HVdc interconnections with Quebec: a 225 MW back-to-back converter at Highgate in northern Vermont and a +/– 450 kV HVdc line with terminal configurations that allow either a 690 MW connection at Monroe in New Hampshire or up to a 2.000 MW connection at Sandy Pond in Massachusetts.

The ISO develops its plans for the networked transmission facilities that provide regional network service to cost effectively address both local and broad system needs. All plans are reviewed to assure that they can be implemented without degrading the performance of the New England system, the NPCC region, or the remainder of the Eastern Interconnection.[125]

The age of equipment is a concern throughout much of New England. In addition to relatively old, low-capacity 115 kV lines, many of which have been converted from 69 kV operation, a number of aging 345/115 kV transformers and generating stations are connected to the 115 kV system. This increases the risk of the system experiencing extended equipment outages, which cannot quickly be repaired or replaced. This infrastructure, which was planned and implemented many years ago, is becoming increasingly inadequate.

[124] One exception is that Aroostook and Washington Counties in Maine are served radially from New Brunswick.

[125] The remainder of the Eastern Interconnection consists of the interconnected transmission and distribution infrastructure that synchronously operates east of the Rocky Mountains, excluding the portion of the system located in the Electric Reliability Council of Texas (ERCOT).

The complexities associated with operating the bulk power system is a major factor that drives the need to improve the transmission system, which can reduce or eliminate these complexities. Many of the transmission system projects underway in the region will facilitate the operation of those areas of the system currently complicated by generator dispatch, the use of special protection systems (SPSs), load levels, and facility outages, for example.

8.2.1 Northern New England

The northern New England area encompasses the Maine, New Hampshire, and Vermont transmission system. This section discusses the features of Northern New England's transmission system and the studies being conducted to address the area's transmission system needs.

8.2.1.1 Northern New England Transmission

The single 345 kV interconnection between New England and New Brunswick leads into a 345 kV corridor at Orrington, Maine, which spans hundreds of miles and eventually ties into Massachusetts. The transmission system through northern New England is relatively limited in capacity. Underlying the limited number of 345 kV transmission facilities are a number of relatively old and low-capacity 115 kV lines, some very long. These lines serve a geographically dispersed load as well as the concentrated load centers in southern Maine, New Hampshire, and northwestern Vermont. Figure 8-1 and Figure 8-2 show the distribution of northern New England's summer-peak load and generation, respectively. Figure 8-3 shows the area's summer-peak transmission flows.

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and may be accessed by calling

ISO New England Customer Service

at (413) 540-4220.

Figure 8-1: Northern New England summer-peak load distribution.

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ISO New England Customer Service

at (413) 540-4220.

Figure 8-2: Northern New England generation distribution.

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and may be accessed by calling

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at (413) 540-4220.

Figure 8-3: Typical northern New England summer-peak transmission flows.

The northern New England transmission system is weak and faces numerous transmission security concerns. The most significant issues facing the area have been to maintain the general performance of the long 345 kV corridor and the reliability of supply to meet demand. The region faces thermal and voltage performance issues and stability concerns and is reliant on several special protection systems that are subject to incorrect or undesired operation (see Section 11.3.6). Rapid load growth has raised particular concerns in northwestern Vermont; the southern and seacoast areas of New Hampshire and Maine; and the tri-state "Monadnock" area of southeastern Vermont, southwestern New Hampshire, and north-central Massachusetts. The system of long 115 kV lines with weak sources and high real and reactive-power losses is exceeding its ability to efficiently and effectively serve load as well as integrate generation. In many instances, the underlying systems of 34.5 kV, 46 kV, and 69 kV lines are also exceeding their capabilities, requiring upgrades and placing greater demands on an already stressed 115 kV system.

Northern New England's resource capability, plus tie lines, provides almost 10,000 MW of generation. Over the last several years, the addition of 3,000 MW of this generation in Maine and New Hampshire, in combination with the area's limited transfer capability, has significantly stressed the northern New England export capability and affected all northern New England resources. This has contributed to an increasing number of stability and voltage-related constraints. Additionally, the commitment and dispatch of a number of northern New England generating resources critically affects transfer capabilities, which creates complex interdependencies that complicate system operations. Equipment maintenance outages, high reactive-power losses, and limited dynamic reactive-power resources further contribute to the potential for stressed conditions in northern New England.

8.2.1.2 Northern New England Transmission System Studies

Study efforts are progressing in various portions of Maine, New Hampshire, and Vermont to address a number of 115 kV system concerns. Many of these studies have focused on defining short-term needs and developing solutions. While some longer-term analyses have been conducted, additional work is required to develop comprehensive solutions for this part of the system.

Maine. The system needs of the Bangor Hydro Electric and southern Maine areas have been identified. The 115 kV transmission lines proposed and under study should address Bangor concerns for the foreseeable future. Central Maine Power is proposing a 115 kV expansion in western Maine to address area voltage issues. Upgrades north of Augusta, including a new 115 kV substation, will address potential voltage concerns. Additional system reinforcements south of Orrington should be explored to address the residual issues, particularly related to high losses and northern-western Maine system performance. Reinforcements at 115 kV, including the addition of a new substation at Maguire Road in southern Maine, will help serve southern Maine load in the near and midterms. However, study results suggest that a new 345 kV source will most likely become necessary, which may connect a future 345 kV line to Three Rivers, South Gorham, or both areas. Additional studies are planned that will examine the alternatives and develop a preferred long-term solution.

New Hampshire. A number of studies of the New Hampshire portion of the system have been conducted. The midterm needs of northern and central New Hampshire will be addressed by closing the Y-138 tie with Maine (see below). A number of 115 kV transmission reinforcements are already under development in southern New Hampshire. Studies have indicated a midterm need for four additional 345/115 kV area autotransformers, most likely at Scobie, Deerfield, and near Newington. Longer-term studies are needed to determine the reinforcements necessary for supporting load growth in these areas. Transmission improvements in New Hampshire intended to address the local growth in demand will likely have the ancillary benefit of improving the overall performance of this transmission corridor. (See below for information regarding the impacts that changes in New Hampshire have on the performance of the transmission system in northern New England.)

Vermont. Study efforts to assess the needs of Vermont have also progressed. A set of transmission reinforcements, the Northwest Vermont (NWVT) Reliability Project, is designed to address the diminishing reliability of the broad northwestern portion of Vermont in the near and midterms. A number of solutions continue to be studied to address concerns in southern Vermont, including subtransmission concerns, specifically between Bennington and Brattleboro. A longer-term analysis being conducted by the Vermont Electric Power Company (VELCO) is confirming concerns highlighted in prior analyses. The results suggest a need for some combination of further expansion of the 230 kV or 345 kV lines. The alternatives for this reinforcement will be studied in conjunction with other future needs in northern New England.

Monadnock region. The Monadnock region encompasses a three-state area of southeastern Vermont (Brattleboro to Bellows Falls and Ascutney), southwestern New Hampshire (from Keene north to Claremont), and north-central Massachusetts (from Pratts Junction to the northern border with New Hampshire). In addition to supplying localized load, the transmission facilities in this region are critical for supplying a wider area, including most of Vermont and northern New Hampshire. A new 345/115 kV substation at Fitzwilliam, New Hampshire, and a number of 115 kV upgrades are being pursued to address existing and midterm voltage and thermal performance concerns. Studies indicate that future transmission system reinforcements will most likely be needed in this area.

8.2.1.3 Northern New England Transmission System Performance Improvement Studies

In addition to conducting the above studies, the ISO is identifying upgrades that will address voltage and stability issues and the thermal performance of key northern New England transmission corridors. These analyses are assessing options to increase the transfer capabilities of the northern New England interfaces and reduce operational interdependencies of specific generator outputs and the related transfer capability of the system. The sections of the system most notably affected by these analyses are as follows:

- Surowiec–South interface
- Maine–New Hampshire interface
- Northern New England Scobie and 394 interface
- North–South interface

The ISO has identified alternatives that address these transmission system performance issues, either individually or in combination. Some of these alternatives, as described in the sections above, have been pursued to address more subregional reliability issues but also have the ancillary benefit of improving the performance of these transmission corridors. The alternatives are as follows:

- **Closing the Y-138 line.** This project, actively being pursued to address central New Hampshire reliability needs, will also provide some limited improvement to the Surowiec–South and Maine–New Hampshire voltage and thermal performance problems. The proposed project plan was approved in January 2006.
- **Eliminating critical Deerfield 345 kV contingencies resulting from the operational failure of key circuit breakers.** This project was designed and implemented to eliminate a critical contingency at the Deerfield substation and curb the potential reduction in the thermal

capability of the Maine–New Hampshire interface. This potential reduction emerged as an issue this year because of load growth. A series circuit breaker, which initially was part of other future changes at the Deerfield substation, was placed in service in May 2006 to address this situation.

- **Looping Section 391 of the Buxton–Scobie 345 kV line into the Deerfield 345 kV substation.** This project would reduce the complexities and interdependencies of the generator output and voltage limits of the Surowiec–South and Maine–New Hampshire interfaces. It could also help improve the thermal-transfer capability of these interfaces.
- **Eliminating critical Buxton 345 kV contingencies resulting from the failure of key circuit breakers.** This project would eliminate critical contingencies that contribute to complex steady-state and stability limitations of the Surowiec–South and Maine–New Hampshire interfaces.
- **Upgrading 115 kV facilities and adding transformers near the southern Maine–New Hampshire border.** These upgrades could address load growth in the coastal area of New Hampshire and southern Maine and help mitigate potential thermal overloads and voltage concerns near the Maine–New Hampshire border during peak-load or shoulder peak-load periods.
- **Adding capacitor banks in western Maine and at Maxcy's.** These additions could improve the Maine–New Hampshire voltage limits and support local voltage requirements.
- **Redesigning the SPS at Maxcy's and Bucksport.** This will eliminate a number of concerns, including poor transient-voltage response in the local area, inadvertent operation, the limited margin for coordination with the normal line-protection equipment, and a discontinuity in the protection provided by the existing system.
- **Adding a 500–600 MVAR static compensator to provide dynamic voltage control at the Deerfield 345 kV substation.**[126] This project would reduce the complexities and interdependencies of the generator output and voltage limits of the Maine–New Hampshire interface and could increase the Maine–New Hampshire and northern New England Scobie and 394 interface stability limitations.
- **Adding a major north–south reinforcement (such as a Scobie–Tewksbury 345 kV line).** Studies are ongoing to examine reinforcements for the 345 kV transmission corridor connecting northern and southern New England, links that are vital to both areas. Significant reinforcement will be necessary to sustain existing levels of north–south transfers at the higher Boston import levels that will be attainable with the Boston-area improvements (see below). Load growth has already illustrated the diminished ability of the key north–south 345 kV facilities to sustain historic transfer levels.
- **Adding a new substation north of Augusta.** This project includes reactive compensation and adds a number of 115 kV transmission lines to address voltage concerns in the area.

8.2.1.4 Northern New England Transmission System Summary

The ISO must evaluate the alternatives discussed above to determine which to implement to address New England's reliability needs. The system changes associated with closing the Y-138 line and addressing southern New Hampshire's needs will also help mitigate thermal and voltage concerns

[126] *MVAR* stands for "megavolt-ampere reactive."

about key area facilities in western Maine. Once the ISO evaluates the base reliability upgrades, it can evaluate the critical interface capabilities. It also can more fully assess the incremental needs and benefits of the other alternatives and recommend the most beneficial ones to pursue. The ISO expects to complete these tasks in 2006.

Eliminating constraints and improving the technical performance of this transmission corridor will become increasingly important as the demand for capacity and fuel diversity in the region increases. While current system conditions might not suggest a need for major system reinforcement, this may change in time. Analyses performed to assess the future security of the transmission system are beginning to indicate further reliability needs within Maine and New Hampshire that may require additional and more significant transmission system reinforcements. These longer-term analyses will continue beyond 2006.

8.2.2 Southern New England

The southern New England area encompasses the Massachusetts, Rhode Island, and Connecticut transmission system. This section discusses the features of southern New England's transmission system and the studies being conducted to address this area's transmission system needs.

8.2.2.1 Southern New England Transmission

The 345 kV facilities that traverse southern New England comprise the primary infrastructure that integrates southern New England, northern New England, and the Maritimes Control Area with the rest of the Eastern Interconnection. This network serves the majority of New England demand, integrating a substantial portion of the region's resources. Figure 8-4 and Figure 8-5 show the distribution of southern New England's summer-peak load and generation, respectively. Figure 8-6 shows the area's summer-peak transmission flows.

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and may be accessed by calling

ISO New England Customer Service

at (413) 540-4220.

Figure 8-4: Southern New England summer-peak load distribution.

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at (413) 540-4220.

Figure 8-5: Southern New England generation distribution.

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Figure 8-6: Typical southern New England summer-peak transmission flows.

The southern New England system serves the majority of load in New England, which is denser than in the north. The area faces thermal, low-voltage, high-voltage, and short-circuit concerns, the most significant being to maintain the reliability of supply to serve load and develop the transmission infrastructure to integrate generation throughout this area. In many areas, an aging low-capacity 115 kV system has been overtaxed and is no longer able to serve load and support generation.

Upgrades to the bulk power system are currently being planned and developed to ensure that the system can meet its current level of demand and prepare for future load growth (see Section 9).

8.2.2.2 Southern New England Transmission System Studies

Study efforts in southern New England have been progressing to address a wide range of system concerns. Recent major efforts have focused on the load areas with the most significant risks to reliability and threats to the bulk power system, particularly the Boston area and southwestern Connecticut. However, efforts have also been undertaken concurrently to address the reliability of other parts of the system. While many of the major efforts have primarily focused on near and midterm concerns, longer-term analyses have also been performed, particularly for the 115 kV system. A significant study effort is still necessary to address all of the near and midterm needs of this area and to develop longer-term comprehensive solutions.

Massachusetts. A number of studies have addressed the Boston and northeastern Massachusetts areas. The short-term NEMA/Boston upgrades were placed in service in the 2001 to 2002 timeframe. The first phase of the NSTAR 345 kV Reliability Project is scheduled to be in service in 2006; the Ward Hill substation reinforcements have already been placed in service. Studies are almost completed to support the addition of a Wakefield substation in the North Shore area, an upgrade that should support area reliability for a longer-term period. Additional reactors have also been placed in service at North Cambridge and Lexington to address high-voltage control. Studies are ongoing to assess the long-term requirements for low- and high-voltage control.

Located to the west of the Boston area, the central Massachusetts transmission system is instrumental in integrating imports from the +/– 450 kV HVdc Phase II interconnection to Hydro-Québec and distributing them to the 345 kV system as well as to the lower-voltage systems. The long-range study of this area resulted in the plan to develop the Wachusett 345/115 kV substation.

Preliminary studies are being conducted to address thermal and voltage concerns in the Cape Cod area because of projected load growth. The previous addition of the Canal–Bourne autotransformer significantly improved the performance of the area's transmission system. The recently completed, second supply to Nantucket and the capacitor additions now provide firm load service to the island. Remedying the adverse system response to the loss of the 345 kV double-circuit canal crossing is currently being studied. Additional voltage support, possibly dynamic in nature, will be determined in a future analysis.

Recent operating experience has identified the need to develop procedures for committing units in lower southeastern Massachusetts. The procedures assure that adequate generation has been committed to address second-contingency protection for the loss of two major 345 kV lines. This situation resulted in significant reliability costs in early 2006. Studies are in progress to address this problem as well as other area reliability concerns.

Study results show that system improvements are needed to support the reliability of the far western Massachusetts area. Two capacitor banks have been installed in 2006, one at the Pleasant 16B substation and one at the Woodland 17G substation. The capacitors eliminate the dependence on Woodland Road Unit #10 but not the Pittsfield generating facility. Studies are being conducted at present to evaluate options to solve the reliability problems in the area.

Massachusetts and Rhode Island. The 115 kV system in the Bridgewater–Somerset–Tiverton areas of southeastern Massachusetts and Rhode Island has some emerging reliability concerns and will be studied in the near future.

Rhode Island. Studies of the Southwest Rhode Island (SWRI) area have identified the need for 115 kV upgrades to address long-term reliability and allow Line 1870's special protection system to retire.

Connecticut. The Southwest Connecticut Reliability Study identified needed reinforcements for the southwestern Connecticut area. Construction is currently in progress for both phases (1 and 2) of the Southwest Connecticut Reliability Project (see below). Studies indicate that additional longer-term area reinforcements may be necessary, particularly in the New Haven area. The planned Norwalk–Glenbrook 115 kV cable circuits should provide long-term reinforcement of the Stamford area.

A number of other Connecticut reliability issues are currently being examined or addressed. Studies are examining alternatives to address low voltages on the 115 kV system in the Naugatuck Valley. Alternatives are being evaluated that can improve reliability in the Groton/Mystic area. The new Haddam 345/115 kV station has been added to improve reliability to the Middletown area, although operating studies suggest that a second 345/115 kV transformer will be needed to maintain longer-term reliability. Study work has not yet begun in association with this second transformer. Additional efforts have developed the Killingly 345/115 kV substation to address reliability in the eastern Connecticut area; studies will be conducted to evaluate the future need for a second 345/115 kV transformer. Study work is also being completed to support the construction of a 345/115 kV substation in the Manchester/Barbour Hill area and to determine whether one or two 345/115kV autotransformers are necessary.

Load growth in the Hartford area is also diminishing area reliability; if local generation is out of service in this area, contingencies could lead to the thermal overload of local transmission lines. Although detailed study work to identify critical timing and develop a well-defined solution has not yet begun, preliminary studies suggest that eliminating the Hartford issues would likely require additional new 345/115 kV transformation, either through the direct addition of a 345/115 kV transformer or the addition of a 345 kV tie and a 345/115 kV autotransformer.

Southern New England region. The ISO continues to analyze the short- and long-term needs of the bulk power system and transmission reinforcements for the southern New England region. Recently conducted regional planning studies had identified a number of different emerging reliability issues, which regional stakeholders had initially pursued solving independently. As described in RSP05, these analyses, which cover a large portion of New England load, had identified many interrelationships among the transmission reinforcement projects in the region, such as for the Springfield area, Rhode Island, and for the Connecticut–Rhode Island–Massachusetts 345 kV bulk supply. As a result, the widespread problems were studied comprehensively to ensure that solutions could be coordinated and would be regionally effective.[127]

The main objective of these studies has been to improve the integration of load-serving entities in Massachusetts, Rhode Island, and Connecticut with generating facilities connected to the 345 kV system; enhance the grid's ability to move power from east to west and vice versa; and identify and resolve reliability issues. The projects are also being developed to address concerns about the area's

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[127] The comprehensive analysis of system needs in the southern New England region was formally known as the Southern New England Transmission Reinforcement (SNETR) plan. As part of this effort, on August 7, 2006, the ISO issued a draft report, *Southern New England Transmission Reliability Needs Analysis.* The report is posted on the ISO's password-protected PAC Web site, which can be accessed by contacting ISO Customer Services at (413) 540-4220.

thermal and voltage violations. These projects will be implemented over a period of years depending on need.

The studies are investigating the following specific problems and concerns:

- The need for additional 345/115 kV transformation capacity in Rhode Island
- Transmission constraints in Rhode Island, especially with out-of-service transmission facilities
- The inability of Rhode Island to access generation on the 345 kV system
- The consequences for eastern New England of the loss of the West Medway (MA) 345 kV station
- The reliability of service in the Springfield area, which depends on the availability of local generation
- Numerous contingency thermal overloads on the Springfield 115 kV system
- The dependence of the Springfield area on the Ludlow–Manchester–North Bloomfield 345 kV line
- The dependence of Connecticut imports on Springfield–North Bloomfield capabilities
- Connecticut’s inadequate infrastructure to move power through the state
- The inadequacy of major ties between Connecticut and Massachusetts and Rhode Island
- The limited ability to use Lake Road capacity to serve Connecticut load concurrent with existing Connecticut import capability

Ongoing studies are examining possible 345 kV and 115 kV reinforcements for these key issues, which could result in a wide range of project components. As is typical, an overriding goal of the analyses is to determine the most regionally cost-effective set of solutions that could provide the maximum benefits and address the problems that have been defined. This comprehensive analysis has preliminarily suggested that many of the problems and solutions remain independent and can and should be pursued separately. Preliminary results also suggest that some of the solutions are codependent and should be pursued collectively.

The most practical alternatives to simultaneously improve the SEMA/RI, East–West, and Connecticut-import interface capabilities appear to be 345 kV reinforcements. The studies to examine these alternatives are considering line-loading and voltage, stability, and torsional-reclosing issues. Some of the alternatives first formulated are no longer being considered because they have been deemed to be physically impractical or infeasible or have failed to address area needs.

Each alternative plan includes transmission solutions to address the transmission security needs of the Rhode Island and Springfield areas, as well as mitigate Connecticut East–West constraints. The final plan will likely include a number of upgrades scheduled for in-service dates potentially ranging from 2008 to 2016. On the basis of the analysis to date, a number of upgrades are required in the Springfield and Rhode Island areas in the short term (2008–2009) timeframe. Further analysis of the 2010 system is currently being conducted to finalize the midterm transmission solutions. Upgrades are being prioritized on the basis of the severity of the conditions under which the upgrades are required. The report of the entire study work is scheduled for completion by fall 2006.

8.3 Major Transmission Projects

Significant progress has been made for improving the transmission system, as identified in previous RSP reports. Major projects nearing construction or recently started include the following:

- **Northeast Reliability Interconnect Project—**comprises a new 144-mile, 345 kV transmission line connecting the Point Lepreau substation in New Brunswick to Orrington Substation in northern Maine and supporting equipment. The line, 84 miles of which are in Maine, is designed to increase transfer capability from New Brunswick to New England by 300 MW and will help improve area stability and voltage performance, as well as provide additional benefits beyond immediate needs. The planned in-service date for this project is the end of 2007.
- **Northwest Vermont Reliability Project—**improves reliability of the northwestern area of Vermont. The project consists of a new 36-mile, 345 kV line, a new 28-mile, 115 kV line, additional phase-angle regulating transformers (PARs), two dynamic voltage-control devices, and static compensation. The planned in-service dates for various components of this project range from late 2006 through 2007.
- **NSTAR 345 kV Transmission Reliability Project—**addresses Boston-area reliability problems and increases the Boston-import transfer capability by approximately 1,000 MW. This project includes the construction of a Stoughton 345 kV station and the installation of three new underground 345 kV lines: one 17-mile cable to K Street Substation and one 11-mile cable to Hyde Park Substation, by 2006, and a second 17-mile cable to K Street Substation in 2007.
- **SWCT Reliability Project—**addresses operating constraints and impediments to generation interconnection and improves the area's near- and midterm reliability and infrastructure. Phase 1 includes a 20-mile 345 kV circuit from Bethel to Norwalk, planned to be in service in 2006. Phase 2 includes a 70-mile 345 kV circuit from Middletown to Norwalk, planned to be in service in 2009.

8.4 Transmission Improvements to Load/Generation Pockets

The performance of the transmission system is highly dependent on imbedded generators operating to maintain reliability in several smaller areas of the system. Consistent with ISO operating requirements, the generators may be required to provide voltage support or to avoid overloads of transmission system elements. Reliability may be threatened when only a few generating units are available to provide system support, especially when considering normal levels of unplanned or scheduled outages of generators or transmission facilities. This transmission system dependence on local-area generating units typically results in relatively high reliability payments associated with out-of-merit unit commitments.

Transmission solutions are needed for the areas where developers have not proposed adding new wholesale electricity market resources to relieve transmission system performance concerns. The ISO is studying many of these areas, and transmission projects are being planned for some areas, while other areas already have projects under construction to mitigate dependence on the imbedded generating units. The following sections describe several of the areas that currently depend on generating units for maintaining reliability and the status of the transmission projects that will reduce the need to run these units.

8.4.1 Major Load Pockets with Generating Units Needed for Maintaining Reliability

The following areas need generators for local reliability support:

- Western Maine
- Massachusetts—the Boston area, the North Shore area, southeastern Massachusetts, western Massachusetts, and the Springfield area
- Connecticut—all generation in the state, in particular, the Middletown area, the Norwalk–Stamford area, and the southwestern Connecticut area

8.4.1.1 Western Maine

Western Maine has generation that has been frequently designated as daily second-contingency generation (see Section 5.1). Studies have been planned to examine transmission alternatives to mitigate this situation.

8.4.1.2 Boston Area

Several units in the Boston area are frequently designated as daily second-contingency units. New Boston Unit #1, approved for deactivation at the end of 2006, has been needed for local reliability support for the Boston downtown area along with Mystic Units #7, #8, and #9. NSTAR is implementing the NSTAR 345 kV Reliability Project to serve future load growth and improve the reliability of this area. With the completion of Phase I of the project (two 345 kV cables) in 2006, New Boston Unit #1 will no longer be required for reliability.

In late 2005 and early 2006, two shunt reactors were installed—one at the North Cambridge 345 kV station and the other at the Lexington 345 kV station. These reactors will help reduce the high-voltage conditions that exist during light-load periods. The goal is to at least reduce, if not eliminate, the need to run local generation specifically for reactive compensation during these periods. The costs associated with running the local generation for this purpose have become relatively high, bringing attention to a significant concern. In addition to continuing to examine further short-term improvements, the ISO is working with NSTAR to complete a long-term reactive study that is determining future VAR requirements for the Boston area. These studies, which should be completed at the end of 2006, are assessing the ability to adequately control voltages and maintain 345 kV system stability over a wide range of operating conditions.

8.4.1.3 North Shore

In the North Shore area, Salem Harbor Units #1 to #4 have been critical for supporting the reliable operation of this area. The North Shore upgrades project (including Ward Hill Substation) helps relieve this area of its near-term need to depend on the Salem Harbor units for reliability. Studies of additional longer-term modifications to this area, including the Wakefield Junction station, should be completed by the third quarter of 2006.

8.4.1.4 Southeastern Massachusetts

In the southeastern part of Massachusetts, the Canal units have been run to control the high-voltage conditions that exist during light-load period and to provide for transmission security during intermediate and peak hours. Studies have not been finalized to determine transmission alternatives to mitigate the dependence on the Canal unit.

8.4.1.5 Western Massachusetts

Altresco is located in an extremely weak part of the system. The Berkshire autotransformer, Bear Swamp autotransformers, and Altresco units make up the primary supply for the Pittsfield area.

Without these facilities, the area relies on a 115 kV transmission system that cannot adequately provide voltage support in the area under certain conditions. Studies of alternative transmission solutions are underway and should be completed by the end of 2006.

The Woodland and Pleasant capacitors have been in service since June 2006, so that Woodland Road is no longer needed to support low-voltage conditions in the Pittsfield area.

8.4.1.6 Springfield Area

Two generators in the Springfield area, West Springfield Unit #3 and Berkshire Power, have frequently been designated as daily second-contingency units. These generators, in addition to West Springfield Units #1 and #2, are also needed to support local reliability during peak hours and to avoid overloads in violation of operating requirements. Studies of alternative transmission solutions are underway for the Greater Springfield area as part of the study of southern New England (see Section 8.2.2.2). The ultimate solutions will provide for load growth and reduce dependence on the operation of these local units. They also may allow for the eventual retirement of the older of these units.

8.4.1.7 Connecticut

All existing generation in Connecticut is required to ensure reliable service until new resources are added or transmission improvements are made in this area. Imports into Connecticut are constrained by both thermal and voltage limits for contingency events. As part of the study of southern New England (Section 8.2.2.2), studies of alternative transmission solutions to improve the supply to Connecticut and the area’s import capability are in progress and should be completed in fall 2006.

8.4.1.8 Middletown Area

Four 115 kV lines and three generators connected to the 115 kV system—Middletown Unit #2 (117 MW), Middletown Unit #3 (236 MW), and Middletown Unit #10 (17 MW)—supply the Middletown, Connecticut, area. Unit #10, 38 years old, is the newest of these units. Middletown Unit #4 (400 MW) is connected to the 345 kV line without transformation to the 115 kV system, so it does not support the local load in the area.

ISO Operations has flagged Middletown Units #2 and #3 as daily second-contingency units that provide critical voltage support to the local 115 kV area. These units help avoid low voltages that would result from single- or double-circuit outages in the area. The most effective solution for providing for future load growth, reducing dependence on the operation of these Middletown units, and potentially allowing the future retirement of the units was found to be building a new 345/115 kV Haddam Substation and implementing other area improvements. The substation and a single 345/115 kV autotransformer have been placed in service; additional 115 kV reinforcements are forthcoming. These changes will significantly reduce the dependence on the Middletown units and will improve the ability to perform maintenance on these units and area transmission. Study work for this area has not yet been scheduled for determining the requirements to add a second autotransformer and alter the line configuration in the area, the later of which could necessitate the alteration of an SPS at the Millstone plant.

8.4.1.9 Norwalk-Stamford Area

The Norwalk–Stamford, Connecticut, area (part of the Greater SWCT area) has been highly dependent on area generation to maintain reliable operation for the general operation and maintenance of the 115 kV system. This generation consists of Norwalk Harbor Unit #1 (162 MW), Unit #2 (172 MW), and Unit #10 (17 MW), and Cos Cob Units #10, #11, and #12 (18 MW each). The two

Norwalk Harbor units have been frequently designated as daily second-contingency units. Phase 1 of the planned SWCT 345 kV Reliability Project will provide for load growth, reduce dependence on the operation of these local units, and may eventually allow for the retirement of these units (see Section 8.3).

8.4.1.10 Southwest Connecticut Area

The ISO has designated many units in the SWCT area, excluding the Norwalk–Stamford area, as daily second-contingency units that must operate because of the limitations of the transmission system in the area. These units are Bridgeport Energy, Bridgeport Harbor Units #2 and #3, Devon Units #11 to #14, Milford Units #1 and #2, and Wallingford Units #1 to #5. The capacity deficiency in this area and the weakness of the existing transmission system have been the basis for the SWCT Reliability Project, Phase 2, which will help reduce the dependence on these units. Measures to relieve capacity deficiencies, such as those included in the SWCT RFP for Emergency Capability Resources (see Section 5.2.1), can provide some relief during OP 4 conditions until the Phase 2 project is built, but these measures are only temporary. Phase 2 (with Phase 1) will also allow for the interconnection of new generation in this area. Other transmission solutions were examined during the process to finalize the current 345 kV project. Phase 1 and Phase 2 reinforcements of the SWCT Reliability Project appear to be on schedule for operation in 2006 and 2009, respectively.

8.4.2 Transmission Plans to Mitigate the Need for Reliability Agreements and Other Out-of-Merit Operating Situations

This section provides information on situations that have resulted in units qualifying for or receiving reliability payments, whether under a Reliability Agreement or for second-contingency or voltage-control purposes. It also lists the reason for the payment and the planned mitigation measures.

Table 8-1 lists by SMD load zone the units that have received or are pursuing Reliability Agreements in 2006. Table 8-2 lists the SMD load zones that contain units not under contract but that did receive annual payments in excess of $1,000,000 in 2005. (A number of other units have received relatively insignificant payments.) Second-contingency and voltage-control payments in SEMA were approximately $12.2 million and $5.8 million, respectively, for the first quarter of 2006. This suggests a projected increase in annual reliability payments for SEMA in 2006 as compared with the annual costs for 2005.

Table 8-1
Generating Units Under or Pursuing Reliability Agreements

Owner/Unit	2005 CELT Summer Capability (MW)	Annualized Fixed-Revenue Requirement	Reliability Requirement	Mitigating Transmission Solutions[a]
NEMA/Boston				
Exelon—New Boston Unit #1	350	$30,000,000	NEMA/Boston capacity and transmission reliability (thermal and voltage)	NSTAR 345 kV Transmission Reliability Project (Phase I)
Dominion—Salem Harbor (one-time project; not standard agreement)	743	$3,375,000[b]	North Shore area and NEMA/Boston transmission reliability (thermal)	North Shore upgrades and NSTAR 345 kV Transmission Reliability Project
Mirant—Kendall Steam Units #1–#3 and Jet Unit #1	73	$7,920,000	Local-area transmission reliability support (thermal)	East Cambridge Substation
Boston Gen— Mystic Units #8 and #9	1,398	$238,253,254	NEMA/Boston capacity and transmission reliability (thermal and voltage)	NSTAR 345 kV Transmission Reliability Project (Phases I and II)
Western Central MA				
ConEd— West Springfield Unit #3	101	$8,292,690	Local-area transmission reliability support (thermal)	Southern New England analyses—Springfield Area Transmission System Reinforcement Study
Berkshire Power	230	$30,199,855	Local-area transmission reliability support (thermal)	Southern New England analyses—Springfield Area Transmission System Reinforcement Study
Pittsfield Gen—Altresco	141	$36,529,015	Local-area transmission reliability support (voltage)	(1) Second Berkshire autotransformer; study to be commenced in 2006. (2) Pleasant and Woodland capacitors; in service, June 2006
Connecticut				
NRG—Devon Units #11–#14	121	$19,692,116	Connecticut-area capacity and SWCT transmission reliability (thermal and voltage)	(1) SWCT Reliability Project (2) Southern New England analyses
NRG— Middletown Units #2–#4	770	$49,611,273	Middletown Unit #4—Connecticut-area capacity Middletown Units #2, #3—area transmission reliability (thermal and voltage)	(1) Southern New England analyses (2) Haddam/Middletown Reliability Project (3) Second Haddam autotransformer
NRG—Montville Units #5, #6, #10, and #11	494	$28,696,612	Connecticut-area capacity and transmission reliability (thermal and voltage)	Southern New England analyses
Milford Power Units #1 and #2	493	$81,622,635	Connecticut-area capacity and SWCT transmission reliability (thermal and voltage)	(1) SWCT Reliability Project (2) Southern New England analyses
PSEG—New Haven Harbor	448	$47,368,806	Connecticut-area capacity and transmission reliability (thermal and voltage)	Southern New England analyses
PSEG—Bridgeport Harbor Unit #2	130	$19,012,116	SWCT transmission reliability (thermal and voltage)	(1) SWCT Reliability Project (2) Southern New England analyses
Bridgeport Energy	451	$57,825,915	Connecticut-area capacity and SWCT transmission reliability (thermal and voltage)	(1) SWCT Reliability Project (2) Southern New England analyses
PPL—Wallingford Units #2–#5	176	$30,720,000	Connecticut-area capacity and SWCT transmission reliability (thermal and voltage)	(1) SWCT Reliability Project (2) Southern New England analyses

(a) Mitigating solutions should help reduce problems and their associated costs but may not necessarily fully eliminate them.

(b) This is a one-time payment, not an ongoing annual cost.

Table 8-2
SMD Load Zones with Generating Units That Are Not Under Reliability Agreements but Have Received Significant Reliability Payments[(a)]

Unit Location	2005 Second-Contingency Payments	2005 Voltage-Control Payments	Reliability Requirement	Mitigating Transmission Solutions[(b)]
NEMA/Boston	$37,772,507	$24,296,072	NEMA/Boston transmission reliability (thermal and voltage)	(1) NSTAR 345 kV Transmission Reliability Project (Phases I and II) (2) Boston voltage study (in progress)
SEMA	$126,198	$11,627,711	SEMA transmission reliability (thermal and voltage)	SEMA voltage study to be scheduled
CT	$34,593,509	$1,008,031	SWCT transmission reliability (thermal and voltage)	SWCT Reliability Project

(a) Major units receiving more than $1 million in reliability payments for 2005.

(b) Mitigating solutions should help reduce problems and their associated costs but may not necessarily fully eliminate them.

8.5 Summary of Key Findings

Transmission upgrades identified in previous RSP reports are progressing, although additional improvements are needed to address overall system transfers, serve major load pockets, and reduce dependence on generating units. Much progress has been made toward completing these improvements through the significant 345 kV projects described in this section. Additional transmission system needs have been identified, and studies are underway to address system performance issues.

Other transmission improvements around the region are required to reliably serve load pockets while reducing dependence on localized generation. These areas include Western Maine, Boston, the North Shore, SEMA, WMA, Springfield, Greater Connecticut, Middletown, Norwalk–Stamford, and SWCT.

Section 9
Needed Transmission-Import Capability for Major Load Pockets and Preferred Locations for Generator Interconnections

Various types of analyses must be conducted to develop and maintain a reliable transmission system. As addressed in Section 8, detailed transmission security analyses often drive transmission-expansion efforts and help to balance the interrelationship between reliably serving load pockets and executing larger inter-area transfers. System impact studies of potential generating resources also affect transmission plans. These studies identify the need for additional transmission associated with an interconnection, which also must be coordinated with overall system-expansion plans.

Another way to show the need for transmission improvements is by evaluating the transmission-import capability of smaller regions. This type of deterministic screening analysis estimates a *load margin*, the difference between the subarea load and the sum of subarea resources plus the existing capability of the transmission system to import power. A positive load margin indicates that the subarea may have an adequate combination of generating resources and transmission-import capability. A negative load margin suggests that the area is a candidate for additional resources, transmission improvements, or load reduction to eliminate the shortfall, or that load might need to be shed post-contingency. Resources available in these load pockets or imports into these subareas could help meet capacity needs.

This section discusses the results of determining the amount of transmission-import capability several major load pockets in New England might need during the planning period. These results identify where and when transmission improvements should be considered and the minimum possible amounts of new resources or demand response that could mitigate the need for transmission upgrades. The section also provides guidance on the preferred locations for and technical challenges of interconnecting new resources, the status of generator projects in the ISO Interconnection Queue, and the potential for these new resources to mitigate the need for transmission upgrades.

9.1 Transmission-Import Needs for Major Load Pockets

The ISO evaluated the adequacy of the transmission-import capability into BOSTON, Greater Southwest Connecticut, and Greater Connecticut. The analyses determined whether the transmission-import capability and internal resources within each subarea will be sufficient to meet the area's minimum transmission needs over the study period (2007 to 2015). Each analysis thus identified the minimum amount of new resources that would need to be added or the minimum amount of load that would need to be reduced to mitigate the need for major transmission upgrades.

In conducting these evaluations, the ISO used the 90/10 forecast for each load pocket in accordance with ISO transmission planning practice. Because the transmission capability in smaller regions or load pockets is typically more limited, these areas have fewer options for taking emergency actions and protecting against situations that could cause cascading outages. Thus, for analyzing these areas, assuming high-stress conditions (i.e., 90/10 loads) is appropriate.

In determining the minimum requirements for reliably serving major load pockets, the analyses accounted for the largest contingency and made adjustments for capacity expected to be unavailable. The analyses considered typical subarea resource outages expected at the time of system peak and, consistent with ISO criteria, resource and transmission contingencies, including second transmission contingencies. In cases where the second transmission contingency is more severe than the largest resource contingency (a credible outage that could occur for a protracted period), a certain amount of post-contingency load shedding may be permissible. This is because the likelihood of a second transmission contingency is relatively low, and the event is typically of short duration.

These analyses do not account for the desired operating characteristics of the local resources, which are covered in the requirements for the locational Forward Reserve Market (see Section 5.1.2). They also do not reflect the results of the detailed transmission planning analyses necessary to ensure transmission security (see Section 8). The transmission-security analyses typically identify the need for more extensive improvements than those identified by the load-margin analyses presented in this section.

The results of these deterministic analyses of subarea load margins and those of the probabilistic analyses of subarea LOLEs, as discussed in Section 4.2, may show that different amounts of local resources are needed. These approaches are complementary and provide different perspectives on the performance of different components of the bulk power system (also see Section 11.3.3).

9.1.1 BOSTON

Table 9-1 shows the calculation of the projected load margin for the BOSTON area. As shown in the table, under the assumed capacity resource and load situation, the BOSTON area has sufficient resources through summer 2015 to meet the 90/10 peak-load forecast. The area can also sustain the largest resource or the second-contingency loss of the most critical transmission facility.

This analysis does not illustrate the ability of the network to withstand extreme contingencies, such as the loss of multiple 345 kV lines at the same time possibly because of a storm, the loss of a major substation, or the loss of a major fuel source to the Boston area. Refer to Section 11.3.8 for information on an ISO initiative that is exploring the ability of the network to withstand these types of events.

Table 9-1
Projected Load Margin for BOSTON, Summer 2007–2014, 90/10 Loads (MW)

Capacity Situation (Summer MW)	2007	2008	2009	2010	2011	2012	2013	2014	2015
Load (90/10 forecast)	5,850	5,960	6,090	6,210	6,350	6,470	6,570	6,660	6,740
Largest resource contingency	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Total requirement[(a)]	**7,050**	**7,160**	**7,290**	**7,410**	**7,550**	**7,670**	**7,770**	**7,860**	**7,940**
Capacity	3,587	3,587	3,587	3,587	3,587	3,587	3,587	3,587	3,587
Assumed unavailable capacity	(212)	(212)	(212)	(212)	(212)	(212)	(212)	(212)	(212)
Mystic Units #8 and #9 Capacity >1,200 MW	(160)	(160)	(160)	(160)	(160)	(160)	(160)	(160)	(160)
Total net capacity[(b)]	**3,215**	**3,215**	**3,215**	**3,215**	**3,215**	**3,215**	**3,215**	**3,215**	**3,215**
2007 import limit	4,600	4,600	4,600	4,600	4,600	4,600	4,600	4,600	4,600
NSTAR 345 kV Transmission Reliability Project Phase II[(c)]	–	300	300	300	300	300	300	300	300
Total available resources[(d)]	**7,815**	**8,115**	**8,115**	**8,115**	**8,115**	**8,115**	**8,115**	**8,115**	**8,115**
Load margin for resource contingencies[(e)]	765	955	825	705	565	445	345	255	175
Additional transmission unavailable[(f)]	(100)	0	0	0	0	0	0	0	0
Load margin for transmission contingencies[(g)]	**665**	**955**	**825**	**705**	**565**	**445**	**345**	**255**	**175**

(a) "Total requirement" is the needed capability of the bulk power system to serve the 90/10 peak load while accounting for the loss of the largest generating resource contingency.

(b) "Total net capacity" is the amount of generation in the area minus assumed outages and the current operating restrictions on Mystic Units #8 and #9 available to meet the area need. This number assumes no retirements or deactivation of existing resources and includes New Boston Unit #1 (350 MW), which is scheduled to be deactivated in December 2006.

(c) The addition of Phase II of NSTAR Transmission Reliability Project, due to be in service by the end of 2007, would make the second transmission contingency less severe than the largest resource contingency, as indicated by the zero value for "additional transmission unavailable."

(d) "Total available resources" equals the sum of total net capacity, transmission import capability, and the added import capability provided by the NSTAR 345 kV Transmission Reliability Project Phase II.

(e) "Load-margin resource contingencies" represent the "total requirement" minus "total available resources."

(f) "Additional transmission unavailable" refers to the difference between the "load margin for transmission contingencies" and the "load margin for resource contingencies," in cases where transmission contingencies are more severe than the largest resource contingency.

(g) "Load margin for transmission contingencies" equals the "load margin for resource contingencies" minus "additional transmission unavailable."

The analysis for the BOSTON area assumed forced outages will be at an expected level, adequate resources will be available in New England to meet the reliability criterion, and no generating units will retire in the area. However, a lack of development of new resources, coupled with unit retirements within BOSTON, would decrease the load margin by the same amount as the size of the lost resource and advance the need to improve transmission, add resources, or both.

The positive load margin in the BOSTON area is the direct result of the NSTAR 345 kV Transmission Reliability Project (see Section 8.3) and the ability to import more power, especially from the south. This suggests that additional major transmission improvements are not likely needed to serve BOSTON in the short term. However, transmission modifications may be required to maintain necessary levels of transfer on the North-South interface while also reliably serving Boston (see Section 8.2.1.3).

9.1.2 Greater Southwest Connecticut

Similar to the results for BOSTON, Table 9-2 shows the needs for transmission imports for Greater Southwest Connecticut for the 90/10 peak-load forecast. As shown by the positive load margin throughout the study period, Greater Southwest Connecticut would have enough import capability and resources over the planning period to meet its forecasted peak load and sustain the loss of the largest resource or most critical transmission facility. This analysis assumed the current level of resources in Greater Southwest Connecticut will be available; adequate resources will be available in New England to meet the resource adequacy criterion; and the SWCT Reliability Project has been implemented. Major new transmission projects beyond the SWCT Reliability Project will not likely be required to support imports to SWCT over the short term.

Any changes in the resource availability within or outside Greater Southwest Connecticut (i.e., retirements or additions) or a change in the timing of the SWCT Reliability Project could affect these results. For example, under 90/10 peak-load conditions, a delay of the Southwest Connecticut Reliability Project Phase 2 would result in approximately 110 MW of load being at risk for resource contingencies in Greater Southwest Connecticut by summer 2010.

Table 9-2
Projected Greater Southwest Connecticut Load Margin, Summer 2007–2015, 90/10 Loads (MW)

Capacity Situation (Summer MW)	2007	2008	2009	2010	2011	2012	2013	2014	2015
Load (90/10 forecast)	3,900	3,975	4,070	4,160	4,265	4,350	4,415	4,465	4,515
Largest resource contingency	451	451	451	451	451	451	451	451	451
Total requirement[(a)]	**4,351**	**4,426**	**4,521**	**4,611**	**4,716**	**4,801**	**4,866**	**4,916**	**4,966**
Capacity	2,383	2,383	2,383	2,383	2,383	2,383	2,383	2,383	2,383
Assumed unavailable capacity	(234)	(234)	(234)	(234)	(234)	(234)	(234)	(234)	(234)
Total net capacity[(b)]	**2,149**	**2,149**	**2,149**	**2,149**	**2,149**	**2,149**	**2,149**	**2,149**	**2,149**
2007 import limit	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350	2,350
SWCT Reliability Project Phase 2 (increase to SWCT import limit)	-	-	-	1,300	1,300	1,300	1,300	1,300	1,300
Total available resources[(c)]	**4,499**	**4,499**	**4,499**	**5,799**	**5,799**	**5,799**	**5,799**	**5,799**	**5,799**
Load margin for resource contingencies[(d)]	148	73	(22)	1,188	1,083	998	933	883	833
Additional transmission unavailable[(e)]	0	0	0	(749)	(749)	(749)	(749)	(749)	(749)
Load margin for transmission contingencies[(f)]	**148**	**73**	**(22)**	**439**	**334**	**249**	**184**	**134**	**84**

(a) "Total requirement" is the needed capability of the bulk power system to serve the 90/10 peak load while accounting for the loss of the largest generating resource contingency.

(b) "Total net capacity" is the amount of generation in the area minus assumed outages available to meet the area need. The values assume no existing resources retire or deactivate and do not include SWCT Gap RFP resources.

(c) "Total available resources" equals the net capacity plus the sum of the transmission import capability and the added import capability provided by the SWCT Reliability Project Phase 2.

(d) "Load-margin resource contingencies" represent the "total requirement" minus "total available resources."

(e) "Additional transmission unavailable" refers to the difference between the "load margin for transmission contingencies" and the "load margin for resource contingencies," in cases where transmission contingencies are more severe than the largest resource contingency.

(f) "Load margin for transmission contingencies" equals the "load margin for resource contingencies" minus "additional transmission unavailable."

9.1.3 Greater Connecticut

Under the 90/10 peak-load forecast shown in Table 9-3, Greater Connecticut could experience a negative load margin for resource contingencies of 175 MW during the summer 2007. This load at risk would grow to approximately 510 MW by 2009 and to 1,440 MW by 2015, assuming no capacity was added or unit attritions took place. This suggests that increasing the Connecticut import limit should be considered, as well as providing Connecticut load with greater access to capacity in Greater Connecticut.[128]

[128] Projects are being investigated as part of the studies of southern New England (see Section 8.2.2.2).

Table 9-3
Projected Greater Connecticut Load Margin, Summer 2007–2014, 90/10 Loads (MW)

Capacity Situation (Summer MW)	2007	2008	2009	2010	2011	2012	2013	2014	2015
Load (90/10 forecast)	7,770	7,920	8,105	8,285	8,485	8,670	8,805	8,920	9,035
Largest resource contingency	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Total requirement[(a)]	**8,970**	**9,120**	**9,305**	**9,485**	**9,685**	**9,870**	**10,005**	**10,120**	**10,235**
Capacity	6,797	6,797	6,797	6,797	6,797	6,797	6,797	6,797	6,797
Assumed unavailable capacity	(501)	(501)	(501)	(501)	(501)	(501)	(501)	(501)	(501)
Total net capacity[(b)]	**6,296**	**6,296**	**6,296**	**6,296**	**6,296**	**6,296**	**6,296**	**6,296**	**6,296**
2007 import limit	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500
Total available resources[(c)]	**8,796**	**8,796**	**8,796**	**8,796**	**8,796**	**8,796**	**8,796**	**8,796**	**8,796**
Load margin for resource contingencies[(d)]	(174)	(324)	(509)	(689)	(889)	(1,074)	(1,209)	(1,324)	(1,439)
Additional transmission unavailable[(e)]	(80)	(80)	(80)	(80)	(80)	(80)	(80)	(80)	(80)
Load margin for transmission contingencies[(f)]	**(254)**	**(404)**	**(589)**	**(769)**	**(969)**	**(1,154)**	**(1,289)**	**(1,404)**	**(1,519)**

(a) “Total requirement” is the needed capability of the bulk power system to serve the 90/10 peak load while accounting for the loss of the largest generating resource contingency.

(b) “Total net capacity” is the amount of generation in the area minus assumed outages available to meet the area need. The values assume no existing resources retire or deactivate and do not include SWCT Gap RFP resources.

(c) “Total available resources” equals to total net capacity plus the import limit.

(d) “Load-margin resource contingencies” represent the “total requirement” minus “total available resources.”

(e) “Additional transmission unavailable” refers to the difference between the “load margin for transmission contingencies” and the “load margin for resource contingencies,” in cases where transmission contingencies are more severe than the largest resource contingency.

(f) “Load margin for transmission contingencies” equals the “load margin for resource contingencies” minus “additional transmission unavailable.”

The evaluation of the transmission-import needs for Greater Connecticut shows an immediate need for resources, transmission improvements, or both. The resources procured through the Southwest Connecticut Emergency Capability RFP (approximately 250 MW), individually or combined with additional demand response, conservation, energy efficiency, or short-term transmission solutions, will be needed through 2008. Greater Connecticut will need transmission improvements or approximately 510 MW of additional resources by 2009 to meet the 90/10 peak-load forecast. Continuing to add resources in Connecticut in amounts greater than the forecasted growth in demand could help defer the need for some major transmission improvements.

9.2 Generator Interconnection

Interconnecting new generating resources is an integral part of developing an adequate and reliable bulk power system. When new resources are properly placed, particularly where they can provide incremental load-serving capability, they can improve the performance of the system and reduce dependence on generators within load/generation pockets.

As a minimum requirement, generation in New England must be interconnected in a manner that does not diminish the capability of the system to serve load. While this is in accord with FERC policy and the ISO's tariff, interconnecting generation pursuant to minimum interconnection standards may not provide incremental capacity. Thus, minimally interconnected resources may not provide significant incremental reliability benefits or necessarily offset economic inefficiencies. Generation owners and other transmission customers may elect to pay for expansion of the power system to enhance their ability to provide or access various market products to address these types of situations. Regional transmission planning efforts have been successful in working toward practical and cost-effective integration of available generation.

In Section 4, Table 4-6 describes the effectiveness of adding resources in various locations to satisfy resource adequacy criteria. In general, the farther south new resources are located in New England and the closer they are to major load centers, the greatest impact they will have on improving resource adequacy.

This section provides some broad and general guidance for interconnecting generation at various electrical locations on the basis of transmission system constraints. Locations where generation interconnection may be more technically challenging are highlighted. Being technically challenging does not imply that interconnection is impossible; it suggests that substantial system reinforcements may be necessary to complete the interconnection or to make the capacity more fully and incrementally available to serve load. This section also highlights where generation might be more capable of incrementally serving load and thus more able to serve load growth.

Generators interested in interconnecting with the system must submit Interconnection Requests to the ISO.[129] This section summarizes the size and location of proposals for new generating units as of June 4, 2006. A number of Interconnection Requests are currently active.

9.2.1 Constraints for Interconnecting New Generation Resources

Considering the technical design and performance of the power system, generation should generally be located near load. This typically reduces losses and exposure to a wide range of system problems, including those related to voltage, stability, and simultaneous "parallel-path" thermal loading. However, if too many resources are located too close together, even when near load, congested capacity issues and short-circuit problems can arise.

All generation additions and significant load reductions must be carefully analyzed. Ideally, the resources should be "right sized," which minimizes the extent of required transmission upgrades. Determining the correct size for a new resource is also necessary where existing generating units may be repowered with a higher capability. At some point, the transmission system will likely need expansion to integrate incremental amounts of generation to serve growing load, even when the generation is geographically very close to the load.

On the basis of recent studies and general observation, in many areas of New England, adding relatively large incremental generation without significantly enhancing the associated transmission creates some basic transmission constraints. Issues with interconnecting generation in various areas of the region are described below. The list is by no means comprehensive and is not without exception:

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[129] A list of proposed generation and transmission projects for which the ISO has received requests for interconnecting to the New England Control Area is available at http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/status/.

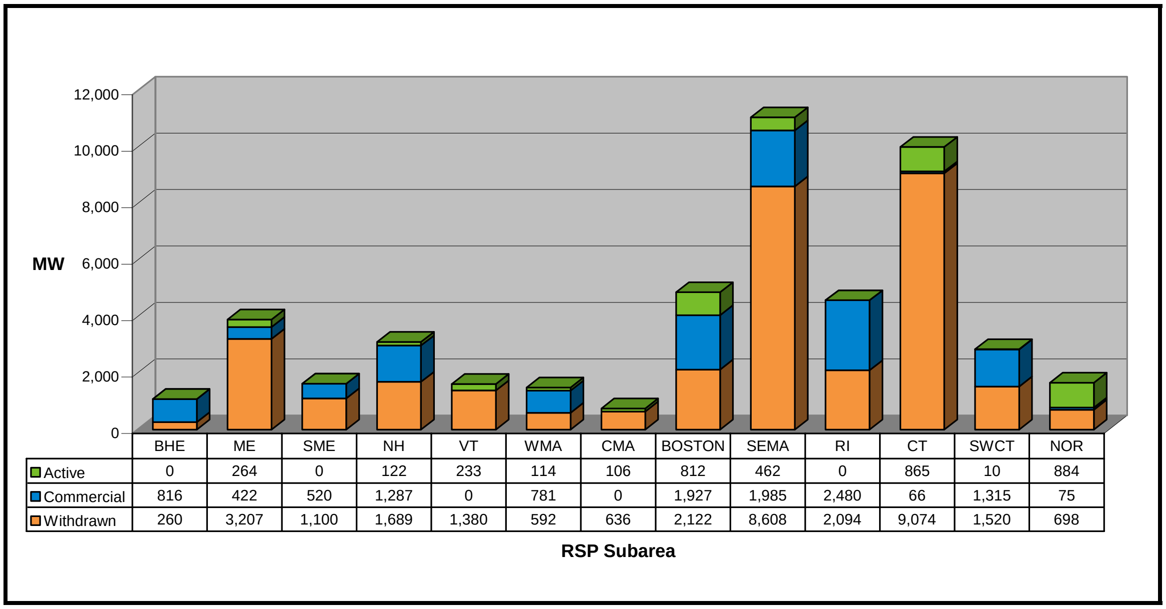
- **Maine**
  - Generation added in western Maine has a tendency to aggravate significant reactive power losses, resulting in complex voltage and stability concerns. Adding smaller units closer to load and major 345/115 kV transformation stations is preferred.
  - Generation added in northern Maine tends to aggravate real and reactive power losses and stability performance when operating in conjunction with existing resources, including potential imports from New Brunswick.
- **New Hampshire and Vermont**
  - Generation added to the 345 kV network in New Hampshire would likely result in locked-in capacity north of the New Hampshire–Massachusetts border. Expanding the 345 kV system south to Massachusetts would be a logical action for taking full advantage of such new resources.
  - Generation added in northwestern Vermont could be helpful in the future. However, adding generation that is too large could create loading and voltage problems that would require mitigation.
  - In northwestern Vermont, new generation at carefully selected locations on the 115 kV network and at lower voltages can potentially provide incremental load-serving capability.
- **North Shore, Massachusetts**
  - Too much generation added in the North Shore could potentially reduce North–South transfer capability and the ability to move power into downtown Boston.
- **Downtown Boston**
  - As in many other urban areas with short high-capacity transmission lines and local generation, adding generation in the downtown Boston area presents challenges related to high levels of short-circuit currents. This issue is currently being studied, and more detailed information will be provided in the future.
- **Western Suburbs of Boston**
  - While some substations in this area have short-circuit capability concerns, additional opportunities for interconnection may exist.
- **Central Massachusetts**
  - New generation at carefully selected locations on the 345 kV and 115 kV networks in this area and at lower voltages can potentially provide incremental load-serving capability. Operating generation at certain locations might not be possible while concurrently importing power from Hydro-Québec at Sandy Pond.
- **Western Massachusetts/Springfield**
  - Adding generation in this area may aggravate or create different loading problems, when considering the operation of new generation in conjunction with existing resources. This area is currently under study for major transmission reinforcements.

- **Southeastern Massachusetts/Rhode Island**
  - New generation at carefully selected locations on the 115 kV network in this area and at lower voltages can potentially provide incremental load-serving capability.
  - Some of the generation located on parts of the 345 kV network in this area, away from the West Medway–West Farnum–Brayton Point loop, can potentially provide some incremental load-serving capability, especially after the completion of the NSTAR 345 kV Reliability Project (see Section 8.3).
- **Central Connecticut**
  - The 345 kV system in this area appears to be able to support incremental generation, particularly following the completion of the Middletown–Norwalk 345 kV transmission facilities. The interconnection design could influence the incremental reliability value of the interconnection.
  - New generation at carefully selected locations on this area's 115 kV network and at lower voltages can potentially provide incremental load-serving capability.
  - Adding some amount of incremental capacity in the Middletown area may be possible; however, the specific size and location of this capacity will influence its incremental load-serving value.
- **Eastern Connecticut**
  - Adding some amount of incremental capacity in this area may be possible; however, generation added east of the Connecticut River that is too large will create constraints between eastern and western Connecticut.
- **Western/Southwestern Connecticut**
  - Prior to the completion of the SWCT Reliability Project (Section 8.3), particularly the Middletown–Norwalk 345 kV facilities, a limited amount of new generation on the 115 kV network and at lower voltages might be able to provide incremental load-serving capability without exceeding short-circuit capabilities in the area. This generation must be properly sized and sited at carefully selected locations in the Norwalk–Stamford area and in northwestern Connecticut.
  - Locating new generation near the Southington and Frost Bridge substations is preferred, since this would provide additional supply near SWCT without having an impact on short-circuit concerns within the area. Following the completion of the Middletown–Norwalk 345 kV facilities, the 345 kV loop from Norwalk through Southington appears likely to become a more effective location for adding incremental load-serving capacity.
  - After the SWCT Reliability Project is complete, SWCT will be more able to support new generation. However, generator size and its specific location on the network will still influence the incremental load-serving value of this generation.

9.2.2 Generating Units in the ISO Interconnection Queue

Figure 9-1 shows the capacity of the 37 active generation-interconnection requests in the ISO Generator Interconnection Queue, presented by RSP subarea, as of June 4, 2006. Most of the active proposed capacity additions are in the NOR, CT, and BOSTON Subareas. As a part of Greater Connecticut, NOR is a preferred location for adding new resources. This area has the most capacity under active development, including two relatively large projects that make up over 80% of the

884 MW proposed for this area. The one proposed project in SEMA, a major wind project, would also provide benefits of improved fuel diversity and reduced environmental emissions (see Section 7).



	BHE	ME	SME	NH	VT	WMA	CMA	BOSTON	SEMA	RI	CT	SWCT	NOR
Active	0	264	0	122	233	114	106	812	462	0	865	10	884
Commercial	816	422	520	1,287	0	781	0	1,927	1,985	2,480	66	1,315	75
Withdrawn	260	3,207	1,100	1,689	1,380	592	636	2,122	8,608	2,094	9,074	1,520	698

Figure 9-1: Capacity of generation-interconnection requests by RSP subarea.

Note: All capacities are based on the project ratings in the ISO Generator Interconnection Queue as of June 4, 2006.

Since the first publication of the Generator Interconnection Queue in November 1997, through June 4, 2006, 35 generating projects out of 158 total generator applications have become commercial.[130] Together, these projects have yielded over 11,600 MW of new capacity in the region. The 37 active projects in the queue total 3,871 MW. Of this total, 575 MW received approval in the past year per Section I.3.9 of the ISO's tariff and have been fully coordinated on a systemwide basis and with neighboring control areas (see Section 11).[131] The withdrawn proposals show the potential for generator development throughout New England.

Since the queue's inception, 84 proposed projects have been withdrawn, suggesting uncertainty associated with the capacity market. Combined with price caps in the energy markets, this uncertainty has failed to provide sufficient incentives for the continued investment in new generation in New England.[132] The recent FERC-approved Forward Capacity Market Settlement Agreement and the Forward Reserve Market are designed to provide the incentives needed to build new resources and locate them where they are most needed.

[130] Many projects have been proposed but have been discontinued because of problems faced during their development related to financing, licensing, insufficient market incentives, or other issues. Refer to http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/status/index.html for specific information on interconnection projects.

[131] For information on the part of the ISO's tariff related to reviewing participants' proposed plans, see http://www.iso-ne.com/regulatory/tariff/sect_1/Section_I_General_Terms_and_Conditions.pdf.

[132] See AMR05 for information on these price caps.

Another indication of the potential to add generation can be seen from the responses to the ISO's December 1, 2003, Gap RFP for Southwest Connecticut Emergency Capability. The responses yielded approximately 850 MW of proposed new generation in the Greater Southwest Connecticut load pocket in addition to demand-response and conservation projects. Not all projects were judged viable.

9.3 Summary of Key Findings

Beginning with the *2001 Regional Transmission Expansion Plan* (RTEP01), the ISO has identified BOSTON, SWCT, and Greater Connecticut as critical subareas.[133] The addition of the NSTAR Transmission Reliability Project and the SWCT Reliability Project have addressed the short-term need for major transmission projects in these areas. A loss of resources in these areas, possibly due to retirements, could advance the need for longer-term transmission improvements. This is particularly true for BOSTON.

Greater Connecticut needs transmission improvements, resource additions, or a combination of both. Without improvements that would increase the import limits into Greater Connecticut, a minimum of 510 MW of new resources or load reduction would be required in Greater Connecticut by 2009, growing to 1,440 MW by 2015. The addition of these resources or load reductions would contribute to reliable system operation and potentially defer the need for transmission improvements for reliability.

Generation can most likely be interconnected in any area of New England with the proper system modifications, and transmission enhancements can be designed to overcome most technical limitations to maximize the reliability value of that generation. Southern New England, especially Greater Southwest Connecticut, is the generally preferred location for adding new generating units, subject to system impact studies that address technical issues. Upon completion of the SWCT Reliability Project, adding generation to the northern and western sections of the 345 kV loop in southwestern Connecticut will likely be the most favorable option. New capacity in the BOSTON area would be beneficial but is subject to technical constraints. An examination of proposed generation projects in the ISO Generator Interconnection Queue suggests the potential for developing needed resources in generally favorable locations of the system.

[133] The ISO's *2001 Regional Transmission Expansion Plan*, October 19, 2001, can be accessed at http://www.iso-ne.com/trans/rsp/2001/index.html.

Section 10
Cost-Impact Analyses of Capacity, Electric Energy, and Transmission Upgrades

The demand for electricity in New England is forecast to grow at a compound annual growth rate of 1.9% over the next 10 years, as discussed in Section 3. This growth in demand will necessitate investing in new generation and transmission for reliably operating the grid. If electricity-usage trends and economic growth continue as expected, substantial investments in generation and transmission infrastructure will be required over the next decade.

To help policy makers understand the benefits and consequences of the available choices for meeting system needs because of the growth in electricity use, this section provides estimates of consumer, production, and capacity costs and wholesale electricity prices for a range of resource-expansion scenarios. The costs of demand growth without system expansion are calculated. These results are compared with alternate scenarios that include adding relatively inexpensive baseload resources and demand-reduction measures. The costs of planned transmission expansion required to support the forecasted growth in demand are also discussed. The results show that electric energy costs can be reduced in a number of ways, including the implementation of aggressive energy-efficiency and demand-side management programs, as well as investment in baseload generating resources with low marginal production costs.

10.1 Capacity and Electric Energy Cost-Impact Scenarios

Several events and circumstances have raised concerns about New England's dependence on natural gas for producing electricity. These include the regional development of large amounts of capacity fueled by natural gas since the introduction of the markets, coupled with limited spot-gas availability during the winter (January 2004 Cold Snap) and the fall 2005 hurricane-related increases in natural gas prices. Policy makers and observers have asked not only how New England can reduce the reliability risks associated with interruptions in natural gas delivery, but also how the region can reduce its exposure to natural gas price volatility.

As discussed in Section 6, the risk associated with volatile natural gas prices may be reduced in a number of ways, which fall into two broad categories. One category is to build low-cost generation. The other is to reduce peak loads to avoid the need to invest in new infrastructure. Electric energy costs could be reduced by displacing high-cost resources with low-cost resources, by reducing the need to build and pay for additional infrastructure, or by a combination of both.

Current market signals appear to provide a strong incentive for building relatively low-cost generation using available technology. Currently, renewables, coal, and possibly even nuclear power appear to be cost-effective options for new generation. While the increased incentive to build is clear, less recognized is the impact that adding baseload resources could have on market prices. Because the lowest-priced resources are selected first for commitment and dispatch, adding an inexpensive resource necessarily displaces the otherwise marginal units, lowering electric energy prices throughout the region. This effect can be significant. To illustrate the potential effects on the wholesale electric energy market of moving the resource mix away from gas- and oil-fired resources, the ISO analyzed the costs of adding baseload generation (other than natural gas or oil fired) that has low marginal production costs.

Reducing peak loads reduces the need to add generation and transmission infrastructure, which lowers costs. Current load profiles require substantial investments for serving load during only a handful of hours each year. Reducing demand in that handful of hours can have a disproportionate impact on future infrastructure needs. Giving customers the opportunity to respond to accurate wholesale electric energy price signals can provide market incentives for them to reduce demand during these times, such as through energy efficiency, load management, distributed generation, and real-time demand response.[134] State-sponsored and merchant programs that assist consumers in more efficiently using resources on the customer side of the meter would enable such consumers to respond to price signals and lower their electricity bills. To illustrate the potential effects of reducing the consumption of electricity, the ISO analyzed the effects of demand reduction on the wholesale electric energy market.

10.1.1 Approach to Conducting the Scenario Analysis

The analysis estimated the electric energy market impact of each alternate scenario using actual loads and offer data for 2005. For each hour of the year, a modeled market price was calculated by stacking the supply offers in order and identifying where supply and demand intersect. This intersection point determined the hourly price.[135] Separate model runs were then executed, with a single change to the input data corresponding to a change in either resources or demand. For example, a baseload resource was added to the supply curve each hour, or a certain amount of energy efficiency was assumed. The prices from these runs were compared with the baseline-calculated prices to estimate the market effect of the various modeled actions, conditional on 2005 fuel prices, actual 2005 resources and availability, and 2005 hourly loads.

The analysis did not consider uncertainties in future fuel prices, retirements of existing generation, or the addition of other new generation, which could affect the degree of reduction in marginal electric energy prices. It also assumed that wholesale electric energy costs or savings are fully passed to consumers. Transmission constraints were not modeled.

The impacts to the capacity market were calculated from the total capacity cost for New England, assuming that the Forward Capacity Market were in place. The net cost of capacity was assumed to be $5/kW-Month ($7.50/kW-Month in the Forward Capacity Auction net of peak-energy rents).[136] Capacity requirements were estimated to change linearly with peak-load growth. Reductions in peak-load growth through demand-response, energy-efficiency, and other measures reduced costs by $5/kW-Month because of reduced capacity needs. The analysis assumed that revenues from the FCM, coupled with revenues from the sale of electric energy and ancillary services, would be sufficient to induce new baseload units; no change was assumed in the annual capacity cost to consumers.

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[134] A more sophisticated analysis of the potential benefits of revealing real-time prices to consumers is available in the workshop presentation, *Simulating the Benefits of Improved Linkages between Wholesale and Retail Electricity Markets*, by Peter Cappers, Bernie Neenan, and Henry Yoshimura. Presented at the Rutgers Advanced Workshop in Regulation and Competition, May 18–19, 2006.

[135] The baseline model results were about 4.7% lower than actual LMPs for 2005, suggesting that the model does a reasonable job of simulating actual market results.

[136] *Peak energy rents* are energy market revenues earned by a "proxy unit," initially with a heat rate of 22,000 Btu/kWh, as defined in Section II, Part V.B the Settlement Agreement. These calculated revenues will be deducted from payments to capacity resources under the FCM. See Devon Power LLC, *Order Accepting Proposed Settlement Agreement*, Docket Nos. ER03-563-030 and ER03-563-055, 115 FERC ¶61,340 (June 16, 2006).

Thus, the scenarios used 2005 electric energy market data and results as indicators for future years. It was assumed that in the future the capacity market will clear at the cost of new entry. Because the future capacity market is still under development, using 2005 capacity-market results was not appropriate.

The following scenarios were modeled:

1) Addition of a 1,000 MW baseload resource with low marginal production costs, such as a nuclear unit

2) Addition of a 1,000 MW new-technology coal generator that submits offers at levels similar to current coal resources in New England, assuming that only this type of coal technology (compared with other coal technologies) could be permitted and sited in the region

3) Assumption of a 5% increase in load over all hours without adding generation

4) Assumption of 5% on-peak conservation (a 5% reduction of load from 7:00 a.m. to 11:00 p.m. on weekdays)

5) Addition of 500 MW of load response activated during on-peak hours when prices exceeded $150/MWh

6) A 10% decrease in natural gas prices over all hours

7) A 10% increase in natural gas prices over all hours

10.1.2 Scenario Analysis Results

Table 10-1 provides model estimates of the changes in wholesale electric energy prices and capacity costs for various scenarios. These results are estimates based on a number of simplifying assumptions and, while indicative of likely effects, should be viewed as having a significant error band. Changes in annual wholesale electric energy prices are shown as percentages and as changes in the total annual consumer electric energy cost.

Table 10-1
Summary of Scenario Results for ISO's Electricity Market (2005 $)[a]

Scenarios	% Change in Annual Wholesale Electricity Price	Change in Total Annual Consumer Costs[b]	Change in Total Annual Production Costs[c]	Change in Total Annual Capacity Costs[d]
		(millions)		
1) Add baseload[d]	-5.70%	-$600	-$470	-
2) Add coal[d]	-5.60%	-$590	-$300	-
3) 5% load growth	5.80%	$600	$420	$90[e]
4) 5% load reduction	-4.70%	-$490	-$360	-$90[e]
5) Load response	-0.02%	-$2	-$0.5	-$30[e]
6) Gas prices -10%	-7.10%	-$740	-$180	-
7) Gas prices +10%	6.80%	$710	$180	-

(a) The analysis does not consider uncertainties in future fuel prices, retirements of existing generation, or the addition of other new generation, which could affect the degree to which marginal electric energy prices are reduced. Transmission constraints also were not modeled.

(b) "Change in total annual consumer costs" is calculated by multiplying the average estimated annual change in hourly prices by annual consumption. Total wholesale electricity costs in 2005 were assumed to be approximately $10.4 billion.

(c) "Total annual production costs" are calculated by subtracting total annual production costs under each scenario from total annual production costs under the 2005 base assumption.

(d) The analysis assumed that revenues from the FCM coupled with other revenues from energy sales and ancillary services would be sufficient to induce new baseload units; no change was assumed in the annual capacity cost to consumers.

(e) Using an ICR of 30,000 MW (approximately the 2005 requirement) at a $5/kW-Month net capacity cost results in a base capacity cost of $1.8 billion/year.

These estimates are intended to be representative of the effects of such actions and investments. Changes in actual consumer costs could vary widely from these estimates. For example, relatively few high-priced hours existed in 2005, the base year in the modeling analysis. An increased number of high-priced hours in future years would increase the calculated savings from load-response programs.

The modeling results suggest that consumer and production costs can be substantially reduced through market investment in relatively low-cost baseload resources and reductions in consumer demand. Consumer costs can be reduced both because of decreased electric energy prices and decreased capacity requirements. It is assumed that market signals will be sufficiently strong for investing in low-cost baseload resources without any additional market incentives or costs. This assumption is based on potential new entrants in the ISO's Generator Interconnection Queue and publicly expressed interest in developing non-gas-fired baseload resources throughout the country. Thus, it is also assumed that capacity costs will not change as new baseload resources displace existing, higher-cost resources.

10.1.3 Scenario Analysis Conclusions

This analysis indicates that without building generation, implementing energy-efficiency or demand-response measures, or conducting a combination of all measures, capacity and infrastructure costs will continue to rise. Fuel prices, primarily for natural gas, will continue to be an important driver of total electricity costs. With the current mix of resources, moderate changes in natural gas prices can have a large effect on the cost of supplying electricity to consumers.

If building new baseload resources with low marginal production costs were economic and these resources were built, the addition of these resources would result in a large decrease in the price of electric energy. Although this analysis did not address the siting of new generation, this is a major issue. Conservation and energy efficiency can produce large savings in both electric energy and capacity costs. Load response, as modeled, has a minimal effect on annual electric energy prices but can significantly reduce capacity costs.

10.2 Transmission System Investment

Since the early 1990s, the capital investment in regional transmission was for integrating many of the larger New England power plants and the Phase II HVdc interconnection to serve load. This investment resulted in developing a fully operable system with a 345 kV network originally intended to serve approximately 20,000 to 25,000 MW of New England load. The surpassing of these load levels, in conjunction with the generation expansion that has occurred over the past several years, has driven the need to significantly upgrade the 345 kV network as well as many 115 kV facilities.

Transmission system costs are largely fixed and do not vary with line usage. These fixed costs include the capital costs for required infrastructure and the annual personnel and organizational costs for system operations and maintenance. All transmission costs are paid for by transmission customers, allocated regionally, locally, or by direct assignment for elective charges.

The tables in this section provide the estimated costs associated with five of the major transmission projects either underway or proposed in New England (see Section 8). These projects include the NSTAR 345 kV Reliability Project (Phases I and II), the SWCT Reliability Project (Phases 1 and 2), the Northeast Reliability Interconnect, and the NWVT Reliability Project. Other major projects are not included in these tables because sufficiently accurate cost projections are not yet available. The cost estimates are based on best available engineering estimates of project costs and reflect only the construction and financing costs of the projects. They do not include annual maintenance costs, which are generally small relative to construction costs.

Table 10-2 provides estimated annual revenue requirements based on 18% of the capital costs included in Table 10-1. These costs are based on approximate historical annual transmission costs incurred by transmission owners.[137] The highest-cost project is the SWCT Reliability Project Phase 2, expected to cost $234 million per year. Table 10-3 shows the total estimated capital costs of each project; these are proportional to the costs provided in Table 10-2. Again, the SWCT Reliability Project Phase 2 is the most expensive project, with an expected cost of approximately $1.3 billion.

[137] The ISO tariff, Schedule 9, describes these annual revenue requirements.
See http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/section2_of_rto_tariff.pdf.

Table 10-2
Estimated Annual Revenue Requirements for Major Transmission Projects in New England

Year in Service	Projects[a]	Expected	Low	High
2005	Miscellaneous[b]	$25,774,882	$23,197,394	$28,352,370
2006	NSTAR 345 kV Reliability Project Phase I	$40,608,000	$36,547,200	$44,668,800
	SWCT Reliability Project Phase 1	$64,260,000[c]	$57,834,000	$70,686,000
	Miscellaneous[b]	$47,419,020	$42,423,588	$52,576,002
2007	NSTAR 345 kV Reliability Project Phase II[d]	–	–	–
	Northeast Reliability Interconnect Project	$19,782,000	$17,803,800	$21,760,200
	NWVT Reliability Project	$23,814,000	$21,432,600	$26,195,400
	Miscellaneous[b]	$13,661,280	$9,913,680	$21,452,643
2008	Miscellaneous[b]	$74,980,620	$54,538,965	$110,933,055
2009	SWCT Reliability Project Phase 2	$234,360,000	$175,770,000	$292,950,000
	Miscellaneous[b]	$26,732,880	$19,374,660	$38,831,490
2010	Miscellaneous[b]	$14,940,000	$10,710,000	$25,380,000
2011	Miscellaneous[b]	$3,258,000	$2,443,500	$4,887,000
2012	No information currently available	–	–	–
2013	No information currently available	–	–	–
2014	No information currently available	–	–	–
2015	Miscellaneous	$11,520,000	$8,460,000	$18,360,000

(a) The table does not include 78 projects for which costs have not yet been estimated and seven projects for which the in-service year has not yet been finalized. The estimated total annual revenue requirements for these projects range from $16,022,250 (low) to $24,543,000 (expected) to $51,124,000 (high).

(b) “Miscellaneous” projects include all other projects for which annual revenue requirements and timing have been estimated and specified in the July 2006 *Transmission Project Listing.*

(c) The $64 million annual revenue requirement includes $21.4 million for Local Network Service (LNS) annual revenue requirements assumed as part of Phase I of the Southwest Connecticut Reliability Project.

(d) The estimated annual revenue requirement reported for this phase of the project is included in Phase I of the NSTAR 345 kV Reliability Project.

Table 10-3
Estimated Capital Costs for Major Transmission Projects in New England

Year In Service	Projects[a]	Expected	Low	High
2005	Miscellaneous[b]	$143,193,788	$128,874,409	$157,513,167
2006	NSTAR 345 kV Reliability Project Phase I	$225,600,000	$203,040,000	$248,160,000
	SWCT Reliability Project Phase 1	$357,000,000[c]	$321,300,000	$392,700,000
	Miscellaneous[b]	$263,439,000	$235,686,600	$292,088,900
2007	NSTAR 345 kV Reliability Project Phase II[d]	–	–	–
	Northeast Reliability Interconnect Project	$109,900,000	$98,910,000	$120,890,000
	NWVT Reliability Project[e]	$132,300,000	$119,070,000	$145,530,000
	Miscellaneous[b]	$75,896,000	$55,076,000	$119,181,350
2008	Miscellaneous[b]	$416,559,000	$302,994,250	$616,294,750
2009	SWCT Reliability Project Phase 2	$1,302,000,000	$976,500,000	$1,627,500,000
	Miscellaneous[b]	$148,516,000	$107,637,000	$215,730,500
2010	Miscellaneous[b]	$83,000,000	$59,500,000	$141,000,000
2011	Miscellaneous[b]	$18,100,000	$13,575,000	$27,150,000
2012	No information currently available	–	–	–
2013	No information currently available	–	–	–
2014	No information currently available	–	–	–
2015	Miscellaneous[b]	$64,000,000	$47,000,000	$102,000,000
Total		**$3,339,503,788**	**$2,669,163,259**	**$4,205,738,667**

(a) The table does not include 78 projects for which costs have not yet been estimated and seven projects for which the in-service year has not yet been finalized. The estimated total capital costs for these projects range from $89 million (low) to $136 million (expected) to $284 million (high).

(b) "Miscellaneous" projects include all other projects for which capital costs and timing have been estimated and specified in the July 2006 *Transmission Project Listing.*

(c) The $357 million capital cost includes $119 million for LNS costs assumed as part of the SWCT Reliability Project Phase 1.

(d) The estimated capital cost reported for Phase II NSTAR 345 kV Reliability Project is included in Phase I project costs.

(e) In 2005, $3 million went into service. It was assumed that $74.8 million would be in service in 2006 for a total project cost of $210.1 million.

10.3 Conclusions on Resource and Transmission System Investment

The continued growth in demand will drive the need to build additional generating resources and increase transmission investment. Each of these actions can raise regionwide consumer costs by hundreds of millions of dollars annually. A 5% growth in demand could raise electric energy costs by approximately $600 million annually and capacity costs by $90 million annually. Transmission costs are expected to increase by over $500 million per year when all projects are built.

These costs can be reduced by a combination of investments in resources with relatively low production costs, energy efficiency, and demand-side management. Building a 1,000 MW baseload resource that has low marginal production costs can reduce consumer energy costs by nearly $600 million per year. Reducing on-peak demand by 5% can reduce consumer costs by nearly $500 million per year. Such investments might result in delaying or scaling back some transmission-expansion projects, further reducing costs. Achieving these results will require coordinated and sustained efforts by policy makers to allow the siting of baseload resources and provide price signals and efficiency programs that lead to significant and ongoing reductions in demand.

Section 11
Status of National, Interregional, and Systemwide Initiatives

The ISO is participating in numerous national, interregional, and systemwide initiatives with DOE, the Northeast Power Coordinating Council, and other control areas in the United States and Canada. The aim of these projects, as described in this section, is to ensure that planning efforts are coordinated to enhance the widespread reliability of the electric power system. The systemwide initiatives are also investigating ways to improve planning efforts in New England and apply advanced technology solutions. These are significant efforts that do not coincide with the RSP cycle.

11.1 National Initiatives of the *Energy Policy Act of 2005*

The *Energy Policy Act of 2005* (amending the *Federal Power Act*) mandates DOE and FERC to ensure the reliability of the transmission infrastructure through system expansion and the implementation of enforceable standards.[138] The EPAct includes provisions related to the federal siting of transmission facilities, called National Interest Electric Transmission Corridors (NIETC), and the establishment of a national Electric Reliability Organization (ERO). The ISO has submitted several filings and initiated other actions on the basis of these provisions and will continue to coordinate key issues with stakeholders.

11.1.1 DOE Study of National Interest Electric Transmission Corridors

The aim of Section 1221 of the *Energy Policy Act* is to ensure the timely siting of needed transmission infrastructure and attention to other issues involving national concerns (e.g., economic growth and security).[139] To further this goal, the act delegates specific yet very different tasks to DOE and FERC.

Through a new Section 216(a)(2) of the act, DOE must designate geographic areas as National Interest Electric Transmission Corridors. These NIETCs are areas that experience, for example, transmission capacity constraints or congestion that adversely affect consumers. Through new Section 216(b) of the act, FERC has the authority to implement several provisions. One provision is to permit construction of specific transmission projects within designated NIETCs, such as if state authorities lack the power to permit the project or consider its interstate benefits or, under certain circumstances, if state authorities fail to authorize the project. Under new Section 216(h)(9)(C) of the EPAct, the U.S. Secretary of Energy must regularly consult with, among others, transmission organizations (i.e., ISOs, RTOs, independent transmission providers, or other FERC-approved transmission organizations). DOE is currently establishing the process and criteria for NIETC designation and is expected to designate the initial NIETC by the end of 2006.

[138] *Energy Policy Act of 2005*, Pub. L. No.109-58, Title XII, Subtitle B, 119 Stat. 594 (2005) (amending *the Federal Power Act* to add a new Section 216).

[139] *Federal Power Act* §216(a)(2).

11.1.2 Electric Reliability Organization Overview

The *Federal Power Act* directed FERC to establish one Electric Reliability Organization.[140] The statutory responsibilities for the ERO include establishing and enforcing standards for the North American bulk power system and periodically publishing reliability reports. The ERO may also perform other, nonstatutory, responsibilities. The North American Electric Reliability Council has filed an application with the commission to be designated the ERO, which is expected to be initiated in the first half of 2007.

11.2 Interregional Coordination

In addition to being part of the federal-level programs affecting the electricity industry, the ISO is participating in the ISO/RTO Council (IRC), an association of the nine functioning North American Independent System Operators and Regional Transmission Organizations. The ISO is also actively participating in NPCC interregional planning activities and a number of other activities designed to reduce seams issues with other ISOs and RTOs.

11.2.1 IRC Activities

Created in April 2003, the ISO/RTO Council works collaboratively to develop effective processes, tools, and standard methods for improving competitive electricity markets across North America. In fulfilling this mission, the IRC balances reliability considerations with market practices that encourage the addition of needed resources. This results in each ISO/RTO managing efficient, robust markets that provide competitive and reliable electricity service.

One IRC activity has been to assist DOE in establishing the process and criteria for NIETC designation. In comments filed on March 6 and April 14, 2006, the IRC submitted its views to DOE on its Notice of Inquiry to establish NIETC.[141]

While the IRC members have different authorities, they have many planning responsibilities in common because of their similar missions to independently and fairly administer the respective wholesale electricity markets in the various regions. Each ISO/RTO leads the planning effort among its participants through an open stakeholder process. This ensures a level playing field for developing infrastructure that is efficiently driven by competition and that meets all reliability requirements.

The ISO/RTO Planning Committee prepared a 2006 report, *ISO/RTO Electric System Planning*, which addresses current ISO/RTO practices, plans, and planning issues.[142]

11.2.2 Northeast Power Coordinating Council

The Northeast Power Coordinating Council is one of a number of power system planning bodies in the United States. It has about 40 members from the utility and public sectors in five control areas, as follows:

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[140] The status of NERC as the ERO can be found at http://www.nerc.com/about/ero.html. The ISO's filings to FERC on the ERO can be found at http://www.iso-ne.com/rules_proceds/nerc_npcc/ero_docs/index.html.

[141] See http://www.oe.energy.gov/DocumentsandMedia/1221_041106.pdf (for comments received as of March 9, 2006) and http://www.oe.energy.gov/DocumentsandMedia/Addendum_050206.pdf (for comments received through May 1, 2006).

[142] This report, published February 10, 2006, is posted at http://www.iso-ne.com/pubs/spcl_rpts/2006/irc_pc_planning_report.pdf.

- The Maritimes (including the New Brunswick System Operator, Nova Scotia Power Inc., the Maritime Electric Company Ltd., and the Northern Maine Independent System Administrator, Inc.)
- New England (ISO New England)
- New York (NYISO)
- Ontario (IESO)
- Québec (Hydro-Québec TransÉnergie)

The council was established not only to prevent major blackouts from occurring, but also to ensure the continued reliability of the electrical network in the northeastern United States and some of the interconnected Canadian provinces. To meet these objectives, the council has established criteria, guidelines, and procedures that address the security and adequacy of the interconnected bulk power supply system.

With the pending formation of the ERO, the structure and responsibilities of NPCC will change. NPCC will file with FERC as a "regional entity" with authority delegated by the ERO to propose and enforce reliability standards. In addition, NPCC plans to provide non-ERO services to its members, including the coordination of studies. ISO New England is committed to the goals and methods of the NPCC organization. The ISO remains determined to plan and operate the New England system in full compliance with NPCC criteria, guidelines, and procedures, and to participate in NPCC interregional studies and planning initiatives.

11.2.2.1 Compliance with NPCC Criteria and Standards

NPCC reliability criteria are specific and mandatory and address a wide variety of factors related to maintaining the reliability and security of the bulk power system. The criteria and standards address the following activities:

- Designing and operating interconnected power systems
- Monitoring the performance of a control area's interconnection frequency
- Meeting customer demands for electricity
- Handling frequency disturbances
- Operating during emergencies
- Shedding load
- Restoring system operations
- Designing, maintaining, and testing system protection equipment
- Maintaining operating reserves
- Rating transmission and generation facilities
- Reviewing and approving system documentation

Through its Reliability Compliance and Enforcement Program, the NPCC assesses and enforces the control areas' compliance with these criteria. In turn, each control area assesses and enforces its market participants' compliance to these criteria. As the administrator of New England's compliance program, ISO New England surveys its participants and has the ability to issue sanctions for noncompliance. The ISO's participants have complied with all NPCC planning requirements and have fully cooperated with the ISO during these efforts. All participants must continue to cooperate because standards are periodically revised or added.

11.2.2.2 Planning for Interregional Resource Adequacy

NPCC initiates studies of its control areas and coordinates member-system plans to facilitate interregional improvements to reliability. The council evaluates control area assessments, area resource reviews, and interim and comprehensive reviews of transmission. The studies also include short-term assessments to assure that developments in one region do not have significant adverse affects on other regions. The NPCC Task Force on Coordination of Planning (TFCP) reviews the adequacy of the NPCC systems to supply load, considering forecasted demand, installed and planned supply and demand resources, and required reserve margins. The review is accomplished in accordance with the NPCC *Guidelines for Area Review of Resource Adequacy* (Document B-8), on the basis of the schedule set forth in the NPCC Reliability Assessment Program.[143] As an active member of NPCC, ISO New England fully participates in NPCC's coordinated interregional studies with its neighboring control areas.

Recognizing the diversity of the Northeast, the NPCC assisted NERC in gathering data to assess the resource adequacy of its five control areas.[144] The results of this study show that among the five NPCC areas, the Maritimes and Québec are winter-peaking systems. Ontario has historically experienced its annual peak demand in the winter. However, in three of the last five years, Ontario's annual peak demand occurred during the summer due to extreme weather conditions. On the basis of normal weather conditions, Ontario is forecast to become a summer-peaking area in 2007. The New York and New England areas continue to be summer-peaking systems. Owing to the mix of winter- and summer-peaking control areas, the wider NPCC region has reserves to share among the control areas during the peaks. Thus, when each of its control areas meets the one-day-in-10-year LOLE resource planning criterion, the resource adequacy of the entire NPCC region is ensured.

Figure 11-1 illustrates the summer installed capacity margins for the five NPCC control areas through 2014 and the actual data from 2004.[145] As illustrated, New England, New York, and Ontario have the lowest margins for the forecast period. Since the Maritimes and Québec areas are winter-peaking systems, summer installed-reserve margins are significantly higher than the other areas within NPCC.

[143] The document is available at http://www.npcc.org/PublicFiles/Reliability/CriteriaGuidesProcedures/B-08.pdf.

[144] NERC, *2005 Long-Term Reliability Assessment,* September 2005; available at http://www.nerc.com/~filez/rasreports.html.

[145] The installed capacity margin is calculated as [(Planned Capacity Resources/Summer Peak Demand) – 1].

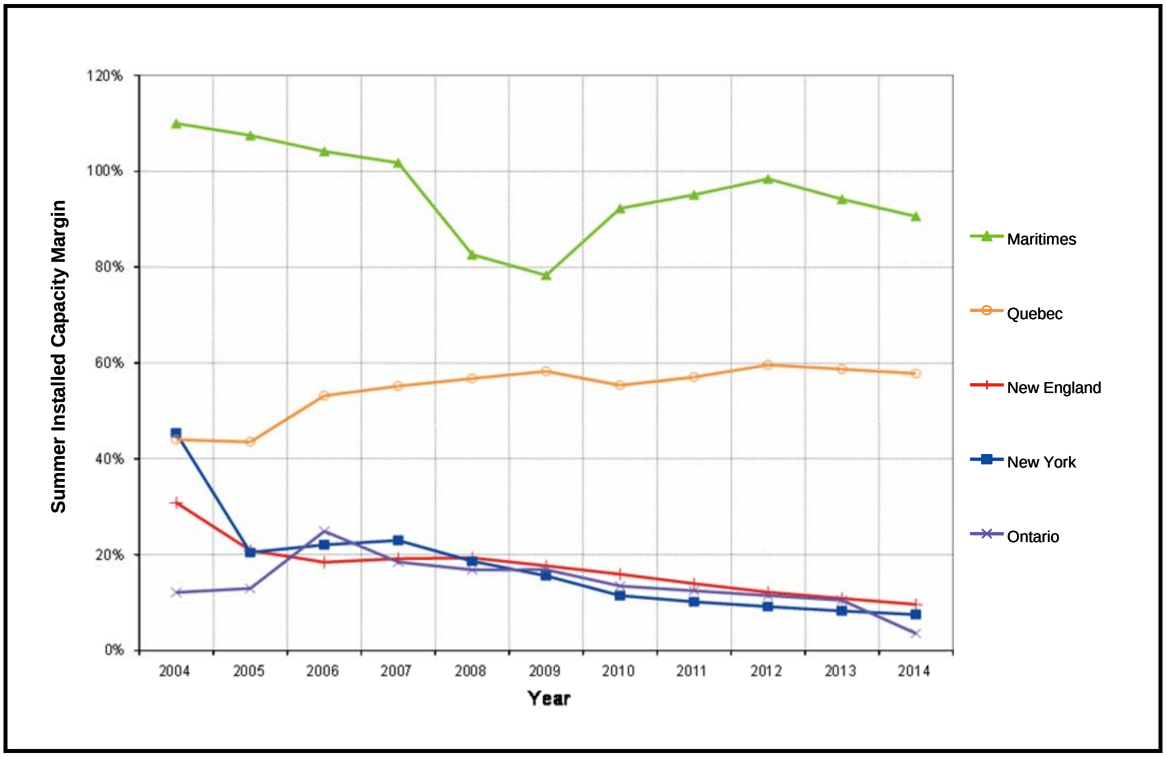

Figure 11-1: Summer installed capacity margins for the NPCC control areas.

Source: NERC, Electricity Supply and Demand Database, 2005 (http://www.nerc.com/~esd/)

According to self assessments by the Ontario, New England, and New York Control Areas, and reported in NERC's *2005 Long-Term Reliability Assessment*, these areas must secure resources to maintain compliance with the NPCC resource adequacy criterion starting in the 2009/2010 timeframe. The Maritimes is projected to meet the resource adequacy criterion through 2014, except for the 2008/2009 year, during which the refurbishment of the 635 MW Point Lepreau nuclear generating station is planned. Hydro-Québec is expected to meet the NPCC resource adequacy criterion through 2014/2015.

These studies indicate that by 2009 the amount of capacity ISO New England will be able to receive from neighboring areas will decrease. NPCC is also reviewing the interconnection benefits available to each of the NPCC areas for 2007 to 2011. The results of this review are not yet available.

11.2.3 Northeastern ISO/RTO Planning Coordination Protocol

ISO New England, NYISO, and PJM follow a Planning Protocol to enhance the coordination of planning activities and address planning seams issues among the interregional control areas. Hydro-Québec TransÉnergie, IESO, and New Brunswick Power participate on a limited basis to share data and information. The key elements of the protocol are to establish procedures that accomplish the following tasks:

- Exchange data and information to ensure the proper coordination of databases and planning models for both individual and joint planning activities conducted by all parties
- Coordinate interconnection requests likely to have cross-border impacts
- Analyze firm transmission service requests likely to have cross-border impacts
- Develop the Northeast Coordinated System Plan
- Allocate the costs associated with projects having cross-border impacts consistent with each party's tariff and applicable federal or provincial regulatory policy

To implement the protocol, the group formed the Joint ISO/RTO Planning Committee (JIPC) and an open stakeholder group called the Inter-Area Planning Stakeholder Advisory Committee (IPSAC).[146] JIPC has issued the *2005 Northeast Coordinated System Plan* (NCSP05) and plans to issue a draft version of the *2006 Northeast Coordinated System Plan* (NCSP06) in fall 2006. IPSAC has discussed the scope of work and draft results of NCSP06. The report will summarize each interregional control area plan and assessment and discuss the following interregional control area issues:

- Resource adequacy
- Fuel diversity
- Cross-border impacts of transmission security, including consideration of loss-of-source contingencies in New England
- Environmental regulations

Loss-of-source contingencies in excess of 1,200 MW could have an adverse impact on the neighboring New York and PJM systems. Studies that examine the possibility of increasing this 1,200 MW limit, possibly through the addition of system improvements, are being conducted. The potential benefits of a higher loss-of-source limit include increased imports from Canada over the HVdc Phase II interconnection, fewer reductions in dispatch of larger nuclear units and Mystic Units #8 and #9, and the allowance of large new generating units.

All planning activities appear to be well coordinated, as shown by the system impact studies and system assessments that more accurately and thoroughly account for neighboring systems. IPSAC has discussed the need for further work, and the JIPC will continue to coordinate study efforts.[147]

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[146] See http://www.interiso.com for more information on IPSAC.

[147] Further information on inter-ISO activities can also be found at the IPSAC Web site.

11.2.4 New England States Committee on Electricity

The six New England States are proposing to form a *regional state committee* to be known as the New England States Committee on Electricity (NESCOE). As defined by FERC, a regional state committee is a forum for state representatives to participate in the RTO's or ISO's decision-making process.[148] NESCOE's aim is to promote policies that result in the regional provision of electricity at the lowest possible price over the long term consistent with the need to maintain reliable service and environmental quality. NESCOE will be a not-for-profit corporation directed by committee with representatives appointed by the governor of each state.

The states have developed a NESCOE Term Sheet for their proposal and are preparing to file the proposal with FERC.[149] The term sheet specifies that NESCOE will focus on resource adequacy and system planning and expansion and conduct a number of tasks, as follows:

- Recommend policies and comment on proposed changes to the market rules and ISO tariff related to resource adequacy, demand response, and energy efficiency within the existing ISO and NEPOOL stakeholder processes
- Provide input on the ISO's annual proposed Installed Capacity Requirement
- Work with regional policy makers to encourage the use of a diverse mix of fuels, including renewable fuels, for electricity generation; customer participation in demand-response programs; and the implementation of cost-effective energy-efficiency programs and retail pricing that aligns with wholesale market pricing
- Recommend policies for ensuring the regional availability of resources that supports electricity reliability
- Where feasible and cost-effective, recommend polices that eliminate persistent and costly congestion over transmission lines and enable the interconnection of generation resources
- Study and evaluate approaches to siting interstate transmission lines on a regional basis
- Work with the Planning Advisory Committee to provide input to the Regional System Plan.

On September 8, 2006, the NEPOOL Participants Committee voted to approve the term sheet.[150]

When NESCOE is formed, the ISO will work with representatives of the committee though the ISO planning process and the PAC to develop the RSPs. The ISO will also continue to work with other representatives of the New England states, primarily through the PAC but also through designated

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[148] FERC, *Wholesale Power Market Platform* (SMD Notice of Proposed Rulemaking White Paper), FERC Docket No. RM01-12-000 (April 28, 2003).

[149] Previous filings related to NESCOE are on file with FERC in Docket No. EL04-112.

[150] For more information on the NESCOE Term Sheet, see http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/prtcpnts/mtrls/2006/sep82006/supplemental_notice_sept8.pdf.

representative organizations, such as the New England Conference of Public Utilities Commissioners (NECPUC) and the New England Governors' Conference (NEGC).

11.3 Systemwide Initiatives

The ISO is also involved in a number of systemwide initiatives designed to improve the reliability and security of New England's bulk power system. These projects are assessing the potential performance of the system 10 years in the future and reviewing methodologies to forecast load and capacity and the performance of special protection systems. Several additional projects are investigating the advanced monitoring and control of the grid and methods to improve voltage support and control.

11.3.1 Imports from Eastern Canada

The eastern Canadian premiers and Canadian utilities have announced a strategy to build significant new hydro resources (4,000 MW to 6,000 MW) by 2015 with the intent to sell power to Ontario and New England during the summer months. Making use of the seasonal load diversity referenced above (see Section 11.2.2.2), some of these provinces would expect to purchase power from the northeastern United States during the winter months. This plan would diversify electric energy supplies for New England and potentially reduce costs to New England electric energy customers.

The ISO will work with stakeholders to develop a comprehensive transmission plan that can accommodate additional transfers between New England and eastern Canada. Close coordination with neighboring systems will be required to ensure reliable system performance between the control areas.

11.3.2 Horizon Year Study/10-Year Planning Assessment

The performance of the New England bulk power system in 2016 must be assessed, consistent with NPCC criteria and in compliance with NERC planning standards. For this effort, the ISO will develop conceptual solutions to address bulk power system deficiencies identified for that period. This 10-year conceptual plan should help establish a basis, direction, and list of priorities for conducting more detailed analyses and developing more refined system plans.

11.3.3 Review of Methodologies to Forecast Load and Requirements for Installed Capacity

In August 2005, the ISO and the region's stakeholders and regulators began to review the methodology used to calculate the region's Installed Capacity Requirement. This review was initially intended to revise the prompt-year ICR. However, the focus of the review was changed to the calculation of the ICR three years in advance to support the expected implementation of the Forward Capacity Market (see Section 4.1.3).

An important aspect of the ICR review is the long-term load forecast. This review occurred during spring and summer 2006. The ISO plans to revise the process to determine the long-term ICRs, and file it with the FERC in the fourth quarter of 2006.

11.3.4 Residential and Workplace Energy-Efficiency Campaign

In summer 2006, the ISO launched a pilot campaign in Massachusetts and Connecticut designed to raise awareness about how to more efficiently use electricity in homes and in the workplace.[151] The

[151] For additional information about this initiative, see http://www.takecharge-ne.org/.

campaign, called *Take Charge New England*℠, provides consumers with information about how decreasing the demand for electricity, especially peak demand, not only lowers wholesale electricity costs, but also prevents the need to add costly power system infrastructure. Through a dedicated Web site; public service announcements on television, radio, and billboards; and a series of events with corporate and government partners and sponsors, consumers have access to tips on how to be active managers of their electricity use. The aim is for consumers to be able to manage electricity costs and preserve electricity resources. Massachusetts and Connecticut were selected for the pilot because these states use the most electricity in New England.

11.3.5 Transmission Planning Practices

As discussed in Section 4, probabilistic analyses have been used to determine local sourcing requirements (the amounts of capacity required in subareas). Deterministic methods have been used to analyze area transmission requirements and identify the conditions under which the transmission system does not meet criteria, expressed as load margins (see Section 9). When evaluating the current practices for assessing the resource adequacy and transmission security of various areas of the New England system, these two approaches may yield different, apparently inconsistent, results. These two approaches are complementary, however, and provide different perspectives on the performance of different components of the power system. Efforts are underway to develop improved means to illustrate this complementary nature and resolve what might appear to be conflicting results. This issue, coupled with the evolving role of the ERO, will necessitate a review of transmission planning practices.

11.3.6 Review of Special Protection Systems

According to NPCC, special protection systems are designed to detect abnormal system conditions and take corrective action other than isolating the faulted elements. These actions include changing load, generation, or the configuration of the system to maintain system stability, acceptable voltages, or power flows.[152] An SPS can be an economical means of improving system response to a given set of conditions without large-scale expansion of the transmission system. New England has effectively used 30 NPCC-approved SPSs over the years.

Including an SPS in a system design requires very careful consideration. It must operate properly when required, and it must not operate when system conditions are such that the SPS response would not be beneficial to the system. As the system evolves, an SPS may become ineffective or operate under conditions that have not been anticipated, resulting in reliability problems.

With the continued expansion of the transmission system throughout New England, some SPSs are being eliminated, and others are being relied on less. In conjunction with transmission owners, and as required by NPCC and as part of its New England Area Review, the ISO periodically reviews the performance and qualification of special protection systems. Applications for all potentially new SPSs are reviewed pursuant to ISO New England Planning Procedure No. 5-5, *Special Protection Systems Application Guidelines.*[153]

[152] See NPCC Document A-07, *NPCC Glossary of Terms*, February 6, 2006, at http://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/a-07.pdf.

[153] This procedure can be accessed at http://www.iso-ne.com/rules_proceds/isone_plan/PP5-5_R1.doc.

11.3.7 Advanced Monitoring and Control of the Transmission Grid

DOE's and Canada's final report on the blackout that occurred in both countries on August 14, 2003, determined that the primary cause of cascading events that took place on that day was inadequate system understanding and situational awareness.[154] Reliability coordinators and transmission operators did not have access to critical transmission system configuration information as the events unfolded during the afternoon of August 14, which limited the system operators' understanding of the state of the bulk power system. If the system operators had understood the state of the system, they and others could have taken actions to prevent the eventual cascading.

To understand and minimize the possibility of a similar event taking place in New England, the ISO is evaluating the data-communication infrastructure and substation controllability of the existing power system. The results of this evaluation will be used to develop recommendations for improving the reliability of data acquisition and ensure that system operators are able to respond and disconnect customer load, if necessary.

11.3.8 Requirements for Local Generation in Large Load Centers

The reliability of large load centers may require local generation to protect against contingencies that are beyond normal criteria. This may require special storm-watch or other procedures that could promote the use of fast-start resources. ISO will work with stakeholder groups to develop suitable system requirements and to update market rules as may be required.

11.3.9 Application of Advanced Technology Solutions

The ISO keeps abreast of new and evolving technologies. New England has already employed such technologies as flexible alternating-current transmission systems (FACTS) and HVdc. Other technologies being considered include superconducting synchronous condensers (SuperVAR), clutches on turbogenerator sets to allow synchronous-condenser operation mode (not yet addressed in the ISO's tariff), and voltage-source converter HVdc. These advanced technology applications allow for improved control of the power network or provide dynamic voltage support. New England is also monitoring the testing of high-capacity ceramic-core overhead conductors in New York and is considering appropriate opportunities to apply these conductors to make more efficient use of existing rights of way. The additional use of dynamic ratings for conductors will also be examined.

11.3.10 Role of Distribution Power Factor in Voltage Support and Control

Transmission owners are responsible for monitoring the load power factor of all connected distribution loads. They also must add or remove transmission and distribution reactive resources to meet the area's voltage requirements consistent with ISO Operating Procedure 17, *Load Power Factor Correction* (OP 17). This can be critical to controlling both low- and high-voltage situations. The ISO is working with stakeholders to examine ways to improve voltage support and control by improving the coordination between the transmission and distribution systems.

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[154] Natural Resources Canada and U.S. Department of Energy, *The August 14, 2003 Blackout One Year Later: Actions Taken in the United States and Canada to Reduce Blackout Risk*. Report to the U.S.-Canada Power System Outage Task Force. August 13, 2004.

11.4 Summary of National, Interregional, and Systemwide Initiatives

Resource adequacy is a common concern for the Northeast, with retirements a potential concern. While New England will benefit from the improved coordination of planning activities, consumer campaigns to reduce demand, and possible increased imports from outside control areas, these measures will not be able to fully solve the capacity and fuel-diversity issues raised in RSP06. In the longer term, additional seasonal diversity power transactions with the eastern Canadian provinces will benefit both areas and generate the need for a comprehensive transmission plan to move power between the regions.

ISO New England's planning activities are closely coordinated with those of neighboring systems as well as with the federal government. The ISO has achieved full compliance with all required planning standards and has successfully implemented the northeastern ISO/RTO Planning Protocol, which has further improved interregional planning among control areas. Sharing capacity resources, particularly during periods of fuel shortages, may become increasingly necessary. Thus, identifying the impacts that proposed generating units and transmission projects can have on neighboring systems is beneficial.

Several ISO initiatives are underway to improve planning and apply advanced technologies to enhance system reliability.

Section 12
Conclusions

Through the publication of the *2006 Regional System Plan* and the issuance of the current *Transmission Project Listing*, the ISO has met the requirements of its FERC tariff to issue an annual RSP. With broad input from regional stakeholders, this plan assesses New England's bulk power system and identifies system improvements required for reliably serving load throughout New England for the next 10 years. The plan will also build on the significant progress the ISO, regional stakeholders, state regulators, elected officials, market participants, and transmission owners have made over the past several years in improving the reliability of the system as a result of the ongoing planning process.

One of the main accomplishments over the last several years has been to recognize the need for new transmission infrastructure. Since 2002, 127 new projects have been completed, representing over $400 million in new transmission investment. Several major 345 kV reinforcement projects have been under construction in 2006, with two projects scheduled for completion by the end of the year. These projects, along with others on the *Transmission Project Listing*, will bring significant reliability benefits to the system while providing a platform to support an efficient and effective power market.

Over the past three years, the region has faced two different, yet significant, challenges related to the availability of fuels used to generate electricity. The January 2004 Cold Snap and the Gulf Coast hurricanes of 2005 each had a major impact on the price and availability of natural gas in the region. Several market participants have recognized the need for a more stable, reliable fuel supply in the winter months and have converted nearly 1,500 MW of capacity from gas-only to dual-fuel capability. While additional efforts are still needed, these measures have significantly contributed to reliably operating the system through winter peak-demand conditions. In addition, new market rules and operating procedures have been developed to provide necessary market and operations information during times of extremely cold weather. ISO Operations personnel are now routinely in contact with their operations counterparts in the gas industry to identify maintenance requirements and share critical system information for supporting reliable operations in times of system stress.

Market outcomes are also slated to improve the types of resources added to the system and the amount of resources added. The approved locational Forward Reserve Market is designed to provide incentives to add new generation and demand-response peaking resources in critical load pockets to support local reliability needs and more efficient market outcomes. The Forward Capacity Market is being designed to provide incentives for meeting regional capacity needs and encourage resources to perform when system needs are most critical.

Although significant progress has been made, RSP06 has identified that the region must develop new resources and transmission improvements to serve the long-term 1.9% annual average growth in demand forecasted for this period. While maximum emphasis is needed on promoting energy efficiency and reducing peak demand, new generation resources are also needed.

This section provides the ISO's conclusions about the planning process, new and alternative resources, fuel diversity, and transmission.

12.1 Status of the Planning Process

The successful operation of the system during the 2006 peak-load periods demonstrated, in part, how proper planning of the system can help ensure adequate capacity and transmission capability. RSP06 and related planning studies continue to benefit from the open stakeholder planning process on a regional and interregional basis. Stakeholders, members of the PAC in particular, provide valuable input on the RSP, including the scope of work, draft results, and final draft plans, which are ultimately subject to ISO/RTO approval.

The ISO is undertaking a number of planning-related initiatives to improve the planning process with the aim of improving the electric power system in New England and in the broader region overall. ISO's participation in NERC, regional reliability councils, and working groups with other ISO/RTOs ensures that the ISO's plans are well coordinated with those of neighboring systems. Continuous planning by the ISO is necessary given the uncertainties of load, electric energy growth, generator performance, fuel prices, and other assumptions and unforeseen events.

12.2 Need for Resources

The New England electric power system needs resources by 2009, and this need will grow. By 2015, the region will need about 4,300 MW, assuming that neighboring control areas can provide 2,000 MW of tie-line benefits to meet resource adequacy criteria. Planned improvements to the market, such as the Forward Capacity Market and Phase II of the Ancillary Services Market project, will provide the incentives for developing the desired quantities, locations, and operating characteristics of system resources, as summarized below:

- The addition of resources in transmission-constrained areas, such as Greater Connecticut, will provide the most system benefit by improving system security and reducing costs to customers.
- The addition of fast-start and demand-response resources in transmission-constrained subareas could reduce the use of more costly resources that provide operating reserves and serve peak load.
- The interconnection of generators near relatively high concentrations of demand especially Greater Southwest Connecticut, is generally preferred.
- An increase in energy efficiency, conservation, and demand response could also help New England meet a portion of its resource needs. In addition to reducing environmental emissions, reducing peak loads would result in the more efficient use of existing system infrastructure, delaying the need to add new resources.

12.3 Need for Fuel Diversity

The region's 40% dependence on natural gas to generate electricity is a serious reliability risk to New England customers, especially during winter peak-demand periods. The following actions are needed to improve the reliability of the system and reduce exposure to price volatility:

- Increase the availability of generators fueled solely by natural gas by converting units to dual-fuel (oil) capability. Alternatively, increase the amount and economic retention of firm gas contracts.

- To improve the region's fuel diversity for the long term, increase renewable generating resources and consider adding new coal and nuclear technologies.
- Add a 1,000 MW low-cost baseload resource with low marginal production costs to lower wholesale electric energy costs and consumer costs. These plants would also improve system reliability.

12.4 Need for Alternative Resources

The development of clean, renewable resources, as well as energy efficiency, conservation, and demand response, can help meet the resource needs of the system consistent with environmental regulations. These measures can also improve the diversity of the fuel supply and defer transmission improvements.

12.5 Need for Transmission

Transmission improvements are needed throughout New England to ensure the reliability of service to New England's major load centers as well as contribute to market efficiency throughout the region. A transmission improvement plan has been developed that coordinates major power transfers across the system, service to large and small load pockets, and requirements with neighboring control areas. Improving the transmission system to reduce system operating complexities, which add risk to maintaining reliability, are important in such areas as northern New England. To comply with transmission security criteria, all projects in the 10-year *Transmission Project Listing* must be completed throughout New England as planned. The ongoing review and modification of the *Transmission Project Listing* will continue to reflect projected changes in the system.

List of Acronyms and Abbreviations

Acronym/Abbreviation	Description
ACP	Alternative Compliance Payment
AEP	American Electric Power
AMR05	*2005 Annual Markets Report*
ARR05	*2005 Annual Reliability Report*
Appendix H	Appendix H of *Market Rule 1*, *Operations during Cold Weather Conditions*
ASM I	Ancillary Services Market Phase I
ASM II	Ancillary Services Market Phase II
BHE	Northeastern Maine Subarea
BOSTON	RSP subarea of Greater Boston, including the North Shore
C&LM	conservation and load-management
CAGR	compound annual growth rate
CAIR	*Clean Air Interstate Rule*
CAMR	*Clean Air Mercury Rule*
CELT Report	*Forecast Report of Capacity, Energy, Loads, and Transmission*
CHP	combined heat and power
CMA/NEMA	RSP subarea that comprises central Massachusetts and northeastern Massachusetts
CMR	*Code of Massachusetts Regulations*
CO	carbon monoxide
CO_2	carbon dioxide
CT	RSP subarea that includes northern and eastern Connecticut
DARD	dispatchable asset-related demand
DG	distributed generation
Document B-8	NPCC *Guidelines for Area Review of Resource Adequacy*
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
DRR Pilot	Demand-Response Reserve Pilot Program
DSM	demand-side management
EBB	electronic bulletin board
EGOC	Electric/Gas Operations Committee
EIA	Energy Information Administration (U.S. DOT)
EPAct	*Energy Policy Act of 2005*
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERO	Electric Reliability Organization
FACTS	flexible alternating-current transmission system
FCM	Forward Capacity Market

Acronym/Abbreviation	Description
FERC	Federal Energy Regulatory Commission
FRM	Forward Reserve Market
GA	Georgia
Gap RFP	Southwest Connecticut Gap Request for Proposal
GCEP	Global Climate Change Energy Project
GHG	greenhouse gas
Greater Connecticut	RSP study area that includes the RSP subareas of NOR, SWCT, and CT
Greater Southwest Connecticut	RSP study area that includes the southwestern and western portions of Connecticut and comprises the SWCT and NOR Subareas
GWh	gigawatt hour
H_2	hydrogen
HQ	Hydro-Québec Control Area
HQICC	Hydro-Québec Installed Capacity Credit
HQ–NE	Hydro-Québec–New England
HVdc	high-voltage direct current
ICAP	installed capacity
ICR	Installed Capacity Requirement
IESO	Independent Electricity System Operator (Ontario, Canada)
IGCC	integrated coal-gasification combined cycle
IPSAC	Inter-Area Planning Stakeholder Advisory Committee
IRC	ISO/RTO Council
ISO	Independent System Operator of New England; ISO New England
JIPC	Joint ISO/RTO Planning Committee
kV	kilovolt(s)
LA	Louisiana
LDC	local distribution company
LFG	landfill gas
LLC	limited liability company
LMP	locational marginal price
LNG	liquefied natural gas
LNS	Local Network Service
LOLE	loss-of-load expectation
M	Maritimes Control Area
MA	Massachusetts
MA DTE	Massachusetts Department of Telecommunications and Energy
MD	Maryland
ME	1) State of Maine 2) RSP subarea that includes western and central Maine and Saco Valley, New Hampshire 3) Maine SMD Load Zone
MMBtu	million British thermal units

Acronym/Abbreviation	Description
MOU	Memorandum of Understanding
MVAR	megavolt-ampere reactive
MW	megawatt(s)
MWh	megawatt hour(s)
N-1	first-contingency loss
N-2	second-contingency loss
NCPC	Net Commitment-Period Compensation
NCSP05	*2005 Northeast Coordinated System Plan*
NCSP06	*2006 Northeast Coordinated System Plan*
NECPUC	New England Conference of Public Utilities Commissioners
NEGC	New England Governors' Conference
NESCOE	New England States Committee on Electricity
NGA	Northeast Gas Association
NGCC	natural gas combined-cycle
NEL	net energy for load
NEMA	1) Northeast Massachusetts Subarea 2) Northeast Massachusetts SMD Load Zone
NEMA/Boston	Combined SMD load zone that includes Northeast Massachusetts and the Boston area
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NH	1) State of New Hampshire 2) RSP subarea that comprises northern, eastern, and central New Hampshire; eastern Vermont; and southwestern Maine 3) New Hampshire SMD Load Zone
NIETC	National Interest Electric Transmission Corridor
NNE	northern New England
NOR	RSP subarea that includes Norwalk and Stamford, Connecticut
NO_X	nitrogen oxide(s)
NPCC	Northeast Power Coordinating Council
NRC	Nuclear Regulatory Commission
NRI	Northeast Reliability Interconnection
NWVT	Northwest Vermont
NY	New York Control Area
NYISO	New York Independent System Operator
ODR	other demand resource
OP 4	ISO Operating Procedure No. 4, *Action during a Capacity Deficiency*
OP 8	ISO Operating Procedure No. 8, *Operating Reserve and Regulation*
OP 17	ISO Operating Procedure No. 17, *Load Power Factor Correction*
OP 19	ISO Operating Procedure No. 19, *Transmission Operations*
OP 21	ISO Operating Procedure No. 21, *Actions during an Energy Emergency*

Acronym/Abbreviation	Description
OPS	Office of Pipeline Safety (U.S. DOT)
PAC	Planning Advisory Committee
PAR	phase-angle regulating transformer
PJM	PJM Interconnection LLC, the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and the District of Columbia
pnode	pricing node
Pub. L.	public law
PV	solar photovoltaic
RAA	Resource Adequacy Assessment
RCSA	Regulations of Connecticut State Agencies
REC	Renewable Energy Certificate
RI	1) State of Rhode Island 2) RSP subarea that includes the part of Rhode Island bordering Massachusetts 3) Rhode Island SMD Load Zone
RFP	Request for Proposal
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
RSP	Regional System Plan
RSP05	*2005 Regional System Plan*
RSP06	*2006 Regional System Plan*
RTEP01	*2001 Regional Transmission Expansion Plan*
RTO	Regional Transmission Organization
SEMA	1) RSP subarea that comprises southeastern Massachusetts, and Newport, Rhode Island 2) Southeastern Massachusetts Load Zone
SMD	Standard Market Design
SME	Southeastern Maine Subarea
SNE	southern New England
SNETR	Southern New England Transmission Reinforcement
SO_2	sulfur dioxide
SF_6	sulfur hexafluoride
SPS	special protection system
Stat.	statute
SuperVAR	superconducting synchronous condenser
SWCT	Southwest Connecticut; Southwest Connecticut Subarea
SWRI	Southwest Rhode Island
TFCP	NPCC Task Force on Coordination of Planning
TMNSR	10-minute nonsynchronized (nonspinning) reserves
TMOR	30-minute operating reserves
TO	transmission owner

Acronym/Abbreviation	Description
Transmission Tariff	*Open Access Transmission Tariff*
TVA	Tennessee Valley Authority
U.S.	United States
VELCO	Vermont Electric Power Company
VT	1) State of Vermont 2) RSP subarea that includes Vermont and southwestern New Hampshire 3) Vermont SMD Load Zone
WCMA	West Central Massachusetts SMD Load Zone
WMA	Western Massachusetts Subarea
WMP06	*2006 Wholesale Markets Plan*
WMP07	*2007 Wholesale Markets Plan*
WSCC	winter seasonal claimed capability
WSP	Winter Supplemental Program