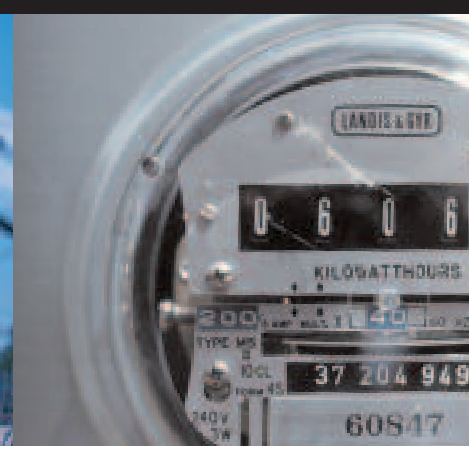
2004

SUMMARY REPORT

REGIONAL TRANSMISSION EXPANSION PLAN



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ISO New England Inc.

RTEP04 SUMMARY REPORT

Approved by the ISO New England Board of Directors

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October 21, 2004

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Overview

ISO New England is pleased to present its Regional Transmission Expansion Plan report for 2004 (RTEP04). This report presents a regional *system* expansion plan that addresses all aspects of planning to ensure the reliable and efficient operation of the New England bulk electric power system and wholesale electricity marketplace.

RTEP04 is the result of a yearlong regional planning effort that examined the bulk electric power system throughout New England. RTEP04 improves on RTEP03 with the following enhancements:

> More comprehensive description of transmission projects.

> Detailed examination of the resource requirements of the system and load pockets[1] in the framework of operable capacity.

> Analysis that provides information on the amount, location, and timing of required resources.

> Inclusion of historical market data and observations.

By identifying system needs, the planning assessment provides information to the wholesale electricity marketplace so that efficient market solutions can be developed to solve power system problems. Such market responses may be investment in generating units, merchant transmission facilities, or demand response programs. RTEP04 also identifies regulated transmission solutions that may be required to ensure reliability and wholesale market efficiency if adequate market solutions do not develop in a timely manner.

[1]Load, or demand, is the amount of electric power required or drawn by electricity users from a power system at any given point in time. A load pocket is an area with limited import capability and/or a lack of local generation to support the load, or demand.

RTEP04 Conclusions

Reliability, while important everywhere, is a serious concern in the load pockets of Boston, Northwest Vermont, and the State of Connecticut. In particular, the load pocket of Southwestern Connecticut is at a critical stage and requires ISO New England to take emergency measures to maintain reliable electric supply during periods of high demand. Reliability is at risk in load pockets due to a number of factors, including:

> Continued growth in electricity use.

> Generating unit retirements.

> Continued transmission bottlenecks.

> Inadequate development of new resources, i.e. new or repowered generation and demand response programs.

Resource reliability could also become a major system-wide issue for New England in two to four years, especially if the region continues to experience the factors noted above. Moreover, heavy reliance on natural gas-fired generators that are subject to interruptions of fuel supply poses potential reliability issues for the winter peak load periods.

Timely completion of transmission projects is critical to preserving and improving reliability region-wide and is key to solving reliability problems in load pockets. Siting or construction delays of critical 345 kilovolt (kV) projects will exacerbate reliability problems, particularly in load pockets, as there is only a limited window of opportunity to repower or redevelop existing generating units in these areas.

Implementing the actions identified in RTEP04, including continued enhancements of infrastructure and market design, will address New England's reliability concerns.

Key RTEP04 Findings

RTEP04 is ISO New England's most comprehensive effort to provide a plan for ensuring system reliability and promoting market efficiency. Major issues addressed include generating resource sufficiency and types needed, transmission adequacy, inter-area coordination, economic issues, and distributed resources. The following are the key findings of the RTEP04 report.

Reliability of Load Pockets

RTEP04 analyzes whether sufficient generating resources are available to meet both peak demand and reserve requirements necessary for system reliability. Results support the need to address serious resource deficiencies in the load pockets of Southwestern Connecticut, the State of Connecticut, Boston, and Northwest Vermont. The major concerns in these areas are continued load growth, potential retirement of several generating units, limited transmission capability into those areas, and limited amounts of planned alternative resources.

Southwestern Connecticut is the most critical load pocket in New England, with current resource deficits that will continue until Phase I of the Southwest Connecticut Reliability Project[2] is in service. ISO New England addresses the current deficit by using resources acquired from the Request for Proposal (RFP) for Southwest Connecticut Emergency Capability[3]. Similarly, the State of Connecticut is resource-tight now and has to rely on emergency actions when there is insufficient capacity to meet demand. This situation is far from the accepted norms of system planning. Unfortunately, this circumstance will continue until the Southern New England Reinforcement Project is in service, which is currently planned for 2008.

Today, Boston has a margin of capacity; however, approximately 1,300 megawatts (MW) of generation has applied for deactivation or retirement, which has been approved for approximately 220 MW by ISO New England. The completion of two key transmission projects, the NSTAR 345 kV Transmission Reliability Project and the North Shore upgrades, currently scheduled for 2005-2008, will improve the Boston Import capability by providing access to additional regional resources.

[2]Detailed transmission projects are defined in section 14 of the RTEP04 Technical Report.

[3]The RFP for Southwest Connecticut Emergency Capability secured resources that will provide approximately 125 megawatts of additional capacity beginning June 1, 2004 and up to 255 MW by the summer of 2007 from demand response resources, including both emergency generation and reductions in electricity use, and from conservation resources. The agreements obtained through the RFP are intended to help fill a reliability gap until a long-term solution to Southwest Connecticut's reliability problem is in place.

Each of these load pockets requires the timely completion of major 345 kV transmission upgrades to reliably serve load and allow the development of new resources. If these transmission projects are not completed, bulk power system reliability will suffer. However, even with planned transmission upgrades, additional resources or repowering of existing resources will be needed within the load pockets to offset potential retirements and meet growing demand. Therefore, ISO New England is creating additional market incentives to promote the development of new resources in the load pockets, including a Locational Installed Capacity (Locational ICAP)[4] market and Ancillary Services[5] markets that reflects the need for operating reserves by location.

System-wide Resource Reliability

Currently, the most critical reliability issues in New England are in the load pockets, while the overall regional system has surplus capacity. However, this surplus is expected to be short-lived as electricity use continues to grow. The New England supply outlook shifts from tight to deficit conditions over the next two to four years.

New England has come to the end of its building boom for new power supply sources. Moreover, some existing generating units needed for system reliability are in jeopardy. There is a potential for over 1,600 megawatts of generator deactivations or retirements. Several of these generating units are located in critical load pockets. Attrition is largely due to age, increased environmental compliance requirements, economic or financial considerations, or a combination of these factors. ISO New England is addressing capacity shortfalls in part through market enhancements, including LICAP and Ancillary Services markets, coupled with emergency actions if needed.

In addition, New England's high dependence on gas-fired generation poses a major risk to ensuring adequate generating unit availability during the winter period, as demonstrated by study results and experience during the January 2004 Cold Snap[6]. More than 9,500 MW of capacity, nearly all gas-fired, have been added in the region since 1999. New England now has approximately 11,540 MW of gas-capable capacity (units that use gas as the primary fuel), of which more than 6,730 MW relies solely on gas ("gas only" sources). This leaves the region vulnerable to perturbations in gas supply, including price fluctuations, delivery constraints, and competition from other uses, such as home

[4]Locational ICAP is a market that promotes reliability in New England by approximately valuing capacity located in areas with limited access to power supplies and encourages investments in new infrastructure where it is needed within the New England region.

[5]Ancillary Services markets provide incentives for investment in operating reserve capacity, such as quick-start generation.

[6]The bitter cold temperatures during January 14-16 put a tremendous amount of stress on New England's electricity and natural gas systems. Constraints on the natural gas pipelines had an impact on the ability of gas-fired generators to operate. ISO New England's report on the Cold Snap can be found on its website at http://www.iso-ne.com/special_studies/.

heating. RTEP04 results show that Boston, Southwestern Connecticut, and Central Massachusetts/ Northeast Massachusetts are the areas most vulnerable to generation shortages resulting from natural gas fuel supply and delivery interruptions. Recent ISO New England actions will make additional capacity available during the winter and improve the reliability situation.

Transmission Projects

The transmission projects described in RTEP04 are needed to maintain bulk power system reliability or to improve wholesale electricity market efficiency. As the system continues to evolve, the need for transmission projects is reevaluated.

RTEP04 includes 246 regulated transmission projects throughout New England, with a total cost ranging from $1.5 billion to $3 billion over the next ten years. The actual costs will depend on the final design of the upgrades. Thirty-nine of the 246 projects are new to this year's plan. Since the publication of RTEP03, 25 projects have been completed.

The timing of key transmission projects serving the load pockets is critical to ensure system reliability and to allow sufficient time to repower existing generation sites or to develop new resources. These projects include the:

- Southwest Connecticut Reliability Project.
- Southern New England Reinforcement Project.
- NSTAR 345 kV Transmission Reliability Project.
- Northwest Vermont Reliability Project.

In addition to addressing critical projects within New England, RTEP04 also addresses an interconnection project with the New Brunswick Control Area. The Northeast Reliability Interconnect Project will provide additional opportunities for capacity and energy diversity exchange with New Brunswick, improved reliability of the transmission system, reduced transmission losses, and lessened dependence on complex special protection systems.

Inter-Area Planning/Coordination

Coordination of inter-regional planning is essential to ensure long-term reliability of the interconnected power system and enhance market efficiency. Improved coordination has been achieved through participation in the North American Electric Reliability Council (NERC), Northeast Power Coordinating Council (NPCC), and interactions with neighboring Control Areas.

Additionally, ISO New England, New York ISO, and PJM Interconnection have signed a protocol that provides a structure to develop inter-area plans and improve overall coordination of planning among the Control Areas. Independent Electricity Market Operator, Hydro-Québec TransÉnergie, and New Brunswick will also participate in the inter-area coordination of planning activities. Initiation of a Northeastern Coordinated System Plan is scheduled for the fall of 2004.

Economic Assessments

The development and implementation of an improved capacity market structure aimed at appropriately valuing resources is essential to maintaining and improving reliability system-wide—particularly in Southwestern Connecticut, the State of Connecticut, and Boston—and to improving wholesale electricity market efficiency. RTEP04 provides historical market information and economic assessments of the future system, as well as the amount, general location, and timing of resources required for these areas.

Distributed Resources[7] and Renewable Portfolio Standards

Distributed resources can play an important role in fostering both system reliability and market efficiency.

While Maine has excess renewable[8] resources to meet its Renewable Portfolio Standard (RPS), Connecticut, Massachusetts, and Rhode Island will require growth in renewable resources. Current plans for renewable projects within New England appear, as a whole, insufficient to meet the projected RPS requirements for 2010.

[7]Distributed resources include demand response and distributed generation. Demand response is the reduction in electricity consumption in response to high real-time wholesale electricity prices or stress on the reliability of the electricity grid. Distributed generation consists of small generators located near or within customer consumption points.

[8]Renewable resources are energy sources that are replenishable by natural forces. They typically include solar energy, wind power, ocean thermal, tidal power, and biomass fuels. States use slightly different definitions for RPS purposes.

Required Actions

The following key actions, encompassing improvements in infrastructure and processes, are required to ensure system reliability and promote market efficiency over the next ten years.

Infrastructure

> Pursue the transmission projects identified in RTEP04, including the Southwest Connecticut Reliability Project, Southern New England Reinforcement Project, NSTAR 345 kV Transmission Reliability Project, Northwest Vermont Reliability Project, and the Northeast Reliability Interconnect Project.

Processes

> Monitor the reliability situation, especially in load pockets. Continue to implement necessary emergency actions and encourage development of new generating and demand-side resources.

> Provide market incentives and promote federal and state policies to encourage the development of resources in load pockets. These market reforms include the development of a Locational ICAP market and the implementation of Ancillary Services markets that reflect the need for operating reserves by location. Market reforms need properly to value the ability to provide energy when needed and thereby provide incentives for the development and utilization of dual fuel capability of existing, new, or repowered generation, and of distributed and renewable resources.

> Examine new methodologies, tools, and market improvements to enhance system reliability and market efficiency. This includes enhancing the methods currently used to calculate resource requirements (Objective Capability) to better consider operational reliability.

> Mitigate, prior to the winter of 2004/2005, reliability concerns regarding over-reliance on gas-fired units by:

1. Establishing an Electric/Gas Operations Committee (EGOC) to improve near-term operations planning and coordination of maintenance of both the electric and gas pipeline systems in anticipation of cold snap conditions. Communication protocols will be consistent with the New England Power Pool (NEPOOL) Information Policy.

2. Developing a new Operating Procedure for cold snap periods. Such a procedure would trigger:

   > Eliminating or canceling "Economic Outages."

   > Switching dual fueled units to alternative fuels on a timely basis.

   > Modifying unit commitment processes to enhance coordination between the electric and gas market nomination timelines.

These actions are expected to improve the availability of gas units by up to 2,000 MW compared to the 2004 Cold Snap experience.

> Implement the Northeast Planning Protocol. This includes issuing a joint Northeast Inter-Area System Plan in 2005 and coordinating the planning of generation interconnections near Control Area borders.

The major highlights of the RTEP04 study are discussed above. More detailed information is presented in the RTEP04 Summary Report and the RTEP04 Technical Report.

An open stakeholder process provided invaluable input to RTEP04. The Transmission Expansion Advisory Committee (TEAC) is composed of a wide variety of representatives from the electric power industry, natural gas industry, and regulatory agencies. ISO New England appreciates the continued support by stakeholders in the RTEP process and welcomes any suggestions or comments.

1.0 Introduction

1.1. About ISO New England

Created in 1997, ISO New England is a not-for-profit corporation responsible for the day-to-day reliable operation of New England's bulk electric power generation and transmission system. It provides oversight and fair administration of the region's wholesale electricity markets and management of a comprehensive regional bulk electric power system planning process.

The Federal Energy Regulatory Commission (FERC) established ISO New England as one of several regional independent system operators (ISOs) to aid in restructuring the wholesale electric power industry into a market system. In 2004, ISO New England gained conditional FERC approval as a Regional Transmission Organization (RTO), which will strengthen its independence and operational control in New England.

ISO New England is independent of any financial interest in the region's wholesale electricity marketplace, and its Board of Directors and employees have no financial ties to market participants.

ISO New England serves Connecticut, portions of Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.

1.2. The RTEP Process

1.2.1. Planning the System

To produce and deliver electricity reliably and economically, a bulk electric power system must accommodate a wide range of system conditions and contingencies. These include continuously varying levels of electricity use, differing amounts and patterns of electrical generation as determined by availability and market prices, and various planned and unplanned generation and transmission outages.

Wholesale electricity markets, such as those operated by ISO New England using Standard Market Design (SMD), are intended to provide economic signals that promote optimal investment in generating units, merchant transmission facilities, and demand response programs to operate the power system efficiently and reliably. Regular system analysis is needed to integrate power system solutions into a cohesive system plan that meets New England's overall load growth needs while ensuring both regional reliability and market efficiency well into the future. This system plan also includes regulated transmission improvements.

1.2.2. Defining the RTEP

ISO New England's Regional Transmission Expansion Plan (RTEP) is a comprehensive assessment comprised of numerous studies and analyses of the region's bulk electric power system that identifies the location and nature of projected system needs. ISO New England assesses the region's bulk electric power grid annually by conducting studies pertaining to the adequacy of generation and transmission resources to meet forecasted demand; economic factors such as congestion costs; the degree of fuel diversity in the region; air emission impacts; and the impact of distributed resources such as demand response and distributed generation.

ISO New England also identifies system problems by conducting technical transmission planning studies with input and analytical assistance from the transmission owners. The transmission plan is updated annually as a part of the planning process to reflect both market responses and changes in system or market conditions. Examples are load growth, resource additions and retirements, timing of transmission upgrades, and regulatory developments that have a potential to impact system performance. All identified transmission solutions are needed to ensure reliability and market efficiency.

1.2.3. How the RTEP Process Works

ISO New England conducts and directs the studies that comprise the RTEP with input and review from the Transmission Expansion Advisory Committee (TEAC). The TEAC is open to any interested party and is composed of a wide variety of regional stakeholders, including market participants (such as generator owners, marketers, load serving entities and transmission owners), governmental representatives, state agencies, representatives of local communities, and consultants.

The TEAC meets regularly throughout the year. ISO New England posts the meeting minutes and presentations on its website. Seven TEAC meetings have been held throughout New England during the RTEP04 process. ISO New England solicits input through a public meeting conducted each year by the ISO New England Board of Directors before it approves the annual plan.

2.0 The Four Pillars: Assuring Reliability Through Markets and Regulated Transmission Investments

One of ISO New England's primary goals is to support the continued reliability of the region's power system using economically efficient competitive wholesale markets and necessary transmission investments. The adoption of markets in New England has yielded real benefits through continued power system reliability. Since the markets were implemented in 1999, the region's capacity has grown by more than 9,500 megawatts, or 40 percent. Demand, however, also grew during that time. Assuming no addition of resources, current generating capacity in New England is forecast to become tight in the next two to four years. If load grows faster than planned or more generation retires, the risk to region-wide reliability will become greater.

In several critical areas of New England, including Southwestern Connecticut, the State of Connecticut, Boston, and Northwest Vermont, the demand for power has outstripped the ability of the existing transmission and installed generation infrastructure to reliably meet local demand. Because the existing transmission infrastructure in these areas limits the amount of power that can be imported from other areas of the region, and local generation is not sufficient, these "load pockets" have reliability problems today. These problems may have an adverse impact on the entire region.

The availability of resources located within load pockets is critical—not only to serve energy demand, but also to provide contingency coverage, transmission support, and flexibility for scheduling construction and maintenance outages. In these load-pocket regions, generators are unable to retire, and ISO New England must enter into special reliability agreements with these generators to ensure resource adequacy.

To further compound the problem, transmission constraints prevent the export of electric power from areas with excess resources, such as Maine and Rhode Island, creating "bottled generation" conditions in those areas. Without access to the marketplace, these constrained units are at risk of retirement. This could occur at a time when the overall system is projected to be short of capacity.

2.1. The Four Pillars

To continue to realize the benefits of competitive markets over the long term, reliable system operation requires a foundation of four elements. ISO New England focuses its efforts on improving and encouraging the development of these "Four Pillars":

> Efficient wholesale market structure.

> Adequate generation.

> Active participation by demand in the markets.

> Reliable transmission system that moves power to where it is needed.

2.2. Efficient Wholesale Market Structure

In March 2003, ISO New England implemented SMD, a major redesign of the region's wholesale electricity markets. SMD provides a structure with efficient and transparent rules and procedures for how electric power is bought and sold; provides efficient pricing and dispatch of wholesale electricity; and sends signals for conservation and investment in generation and transmission in congested areas. The result is overall enhancement of power system reliability. SMD also has begun the process of aligning the region's market structure with those of other Northeastern markets to facilitate trade.

The following wholesale markets either currently exist or are under development.

2.2.1. Energy Market

Under SMD, the energy market consists of eight load zones, each with a unique Locational Marginal Price (LMP). The LMP system reflects the real-time and day-ahead costs of energy, losses and congestion within each load zone. The initial implementation of SMD has been successful, and New England's wholesale electric energy market is highly competitive. Experience to date with SMD indicates that, because of the offer cap on the energy market and the difficulty in properly pricing energy in conditions of shortage, the energy market alone may not be sufficient to send proper price signals to support reliable operation of existing generation and investment in new generation. ISO New England is developing additional electricity markets to value capacity and ancillary services. These markets are described below.

2.2.2. Capacity Market

Constraints in the New England transmission infrastructure create an environment in which capacity resources in one location cannot always be used in (or delivered to) another location. Because of these constraints, it is more valuable to add new generation capacity or reduce load in areas of shortage, rather than in areas with an excess of such resources. Unfortunately, the current Installed Capacity market (ICAP) does not recognize the differences in the value of capacity based on its location. For example, under the current design, a resource located in a congested zone or one with high load growth would receive the same capacity compensation as a resource located in an uncongested zone or one with excess capacity. As a result, investment to construct new generation and enhance existing capacity is not taking place where it is needed most, and some resources (both newer and older resources) in congested or high load-growth regions are seeking to retire.

Additionally, prices in the single ICAP market have a tendency to become unstable around the point at which generation capacity is just sufficient to meet the resource planning criteria of loss-of-load expectation of one day in ten years. In other words, in the current ICAP market, prices become very high if the region has a slight shortage of generating capacity, but quickly collapse toward zero if the region has a slight excess of capacity. This uncertainty and instability in capacity-market prices have further discouraged investment in new and existing capacity.

To solve these problems, the FERC has ordered the implementation of a Locational Installed Capacity (Locational ICAP) market, effective on January 1, 2006. Locational ICAP will differentiate the value of resources based on their location. In addition, the Locational ICAP market will utilize a downward-sloping demand curve to price capacity in each ICAP region. As a result, prices for capacity will increase as shortage conditions occur, and the demand curve will improve the stability of Locational ICAP prices.

The introduction of Locational ICAP should help provide the appropriate price signals to encourage investments in new and enhanced existing resources in load pockets and congested zones.

2.2.3. Ancillary Services Market

In addition to energy and capacity, a reliable power system needs adequate operating-reserve resources. Operating-reserve resources respond quickly to short-term reliability problems on the electricity grid. ISO New England is currently developing an Ancillary Services market for resources that can function as reserves by either reducing load or providing additional generation within 10 to 30 minutes of the operator's request.

The initial implementation of SMD did not provide a market for resources that start up quickly and provide energy for a short period of time. New England does not have a surplus of such "quick-start" resources. To address the lack of a market signal for "quick-start" resources, ISO New England introduced a Forward Reserves market in December 2003. Furthermore, the 2005-2006 Wholesale Markets Plan includes the development and implementation of the Ancillary Services market that will price operating reserves locationally.

The implementation of an Ancillary Services market is consistent with both FERC's Wholesale Market Platform and the New York ISO's planned reserves markets. ISO New England is currently planning to implement its Ancillary Services market in 2005. The Ancillary Services market will enable dispatchable loads as well as generating resources to participate in the real-time energy dispatch and to provide ancillary services.

2.3. Adequate Generation

A fundamental underpinning of a reliable power system and efficient and competitive wholesale markets is ensuring that there will be sufficient long-term electricity supply to meet demand.

Currently, New England as a whole has adequate generating resources. However, in the next two to four years, the region may experience tighter capacity margins as demand increases and existing power plants retire due to age, tightened environmental compliance requirements, or financial insolvency. No large plants are currently under construction to add significant new generation to the system. Moreover, 37 percent of New England's electric capacity is fueled primarily by natural gas. This means the region is increasingly reliant on a single fuel source, leaving it vulnerable to perturbations in the gas supply, including price fluctuations, delivery constraints, and competition from other uses such as home heating.

The combination of capacity, energy, and ancillary services markets is designed to properly price capacity, energy and ancillary services to support investments in the right type of generation and at the right locations.

2.4. Active Participation by Demand in the Markets

Demand participation in the markets plays a critical role in supporting system reliability as well as market efficiency and competition. During tight capacity situations, demand participation increases reliability by providing additional resources to address short-run operating and reserve shortages.

Electricity users' participation in the marketplace enables wholesale prices to be set more efficiently, as proper interaction of supply and demand ensures that the right amount of power is produced and consumed at an economic price. By stabilizing price fluctuations and mitigating supplier market power, demand participation reduces the need for market interventions such as price caps and price-mitigation rules.

ISO New England currently administers several demand response programs that provide financial incentives for large commercial users to reduce power use during tight supply periods or when wholesale electricity prices are high. Enrollment in these programs, which currently has participants committed to reducing or offsetting over 350 megawatts of consumption, has significantly increased since ISO New England implemented locational marginal pricing under SMD in 2003. This was the time when prices first indicated where conservation was most valued. New incentives continue to be introduced to encourage wider participation in these conservation efforts.

Today's demand response programs, while important, constitute only a beginning. On the retail level, current regulatory pricing structures insulate end-use customers from high real-time wholesale prices, so that there is little incentive for them to conserve. Going forward, ISO New England is advocating market rules, retail rate designs, and investment in infrastructure that will allow for the full integration of demand in the wholesale markets. This will enable a competitive demand-side response to price increases in the wholesale markets.

2.5. Reliable Transmission System that Moves Power to Where it is Needed

The transmission system must meet reliability standards and enable generation in New England to serve demand efficiently. RTEP04 identifies and describes in detail needed transmission upgrades in all six New England States.

ISO New England's RTEP process has identified 246 reliability transmission upgrades and additions, which total between $1.5-$3 billion, that are necessary to reinforce the system and create stronger links between generation and demand centers. Major "backbone" 345 kV transmission and related system upgrades, currently in the siting process in Southwestern Connecticut, Boston, and Northwest Vermont, must be acted on as soon as possible to address near-term supply issues. However, because of the time it takes to complete major transmission projects, there is only a short window of time after the new projects are placed in service to allow repowering of older/inefficient generating units in the load pockets before additional load growth will impair the viability of this option.

ISO New England's recent conditional designation as an RTO by the FERC will strengthen its ability to manage the region's bulk electric power system and competitive wholesale electricity markets. A regional approach to transmission is important both for reliability and efficiency because power flows and is traded among suppliers and consumers on a regional basis. Equally critical is the coordination of a cohesive overall system plan with neighboring systems.

2.6. Conclusion: A Balanced Portfolio of Resources

Investments in new resources come in two forms: (1) market-based investments in generation, merchant transmission, and demand response, and (2) regulated investments in transmission system upgrades. Profit expectations based on current and expected market prices for energy, capacity, and ancillary services drive market-based investments in generation, merchant transmission, and demand response. Transmission facilitates economic trade and reliable transfer of energy, capacity, and ancillary services from their sources of production to points of consumption.

3.0 Current Generation Resources

The New England regional electric system serves 14 million people in a 68,000 square mile area. Electricity is produced at over 350 generating units, representing approximately 31,000 megawatts (MW) total generating capacity, all connected to approximately 8,000 miles of high-voltage transmission lines. New England is connected to its neighbors by 12 interconnections with New Brunswick, New York, and Quebec. In addition to generating capacity, approximately 350 MW of resources in ISO New England's Demand Response Program were available for the summer 2004 period.

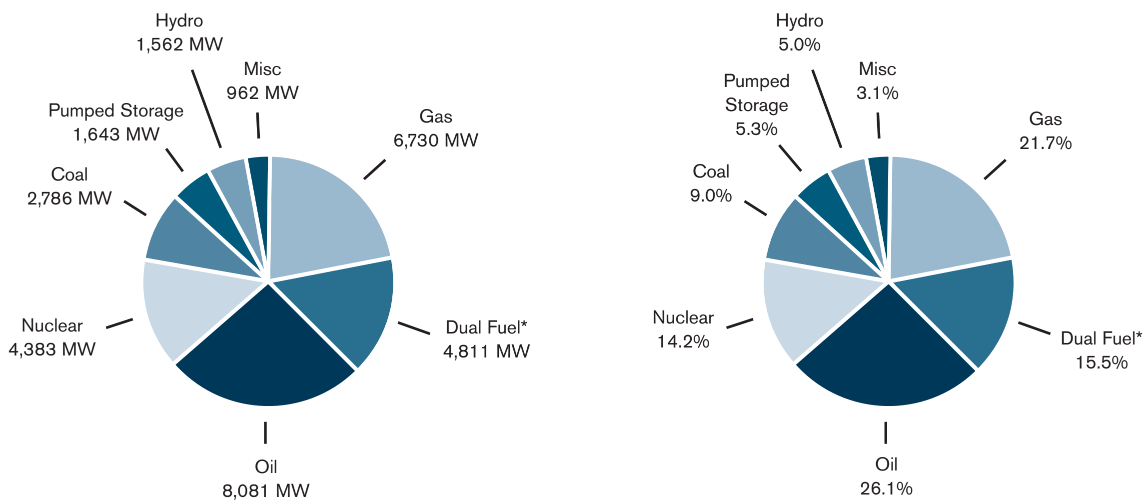
Figure 3.1 shows New England installed capacity[1] by primary fuel type. Fossil-fueled capacity accounts for approximately 72 percent of the installed capacity. This includes natural gas-fueled capacity with approximately 37 percent of the total (about 42 percent of those gas units have dual fuel capability[2]), oil-fueled capacity with 26 percent, and coal-fired capacity at 9 percent of the total. Nuclear capacity represents approximately 14 percent of total New England installed capacity, while hydro capacity (including pumped storage) contributes about 10.5 percent. The remaining 3 percent is renewable generation consisting of refuse, wood, wind, etc.

[1]Generation adequacy is measured in two ways. Capacity is the ability of the installed generation in a region to serve peak demand for electricity, measured in megawatts (MW). Energy is electricity generated (or consumed) over time, measured in megawatt-hours (MWh). Capacity measures are useful for analyzing a system's ability to reliably supply energy at periods of peak electricity consumption. Energy measures are useful for analyzing the fuel diversity of the generation in a region and the region's vulnerability to fuel supply shortages.

[2]Based on information provided by NEPOOL Participants and reflected in the NEPOOL 2004-2013 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT). There are likely fewer units able to switch fuels in a timely fashion. A study is underway to refine these numbers.

FIGURE 3.1

New England Installed Capacity by Primary Fuel Type Assumed in RTEP04 Summer 2004 MW and Percent



Total = 30,958 MW

Total = 99.9% (due to rounding)

*** Dual fuel capacity based on units with gas as primary fuel.**

Table 3.1 indicates the type, fuel use, and age of New England generating units. As shown in this table, the largest amount of capacity was installed during the 20-year period 1971 to 1990. The largest component from that period is nuclear capacity, representing 35 percent of the total. Of the units that went into service between 1951 and 1970, fossil steam units make up 84 percent of the total capacity for that period.

TABLE 3.1

Age of New England Generating Units by Unit[3] Type – Summer 2004

	In-service date prior to 1950		In-service date 1951-1970		In-service date 1971-1990		In-service date 1991 and after		Total	
	# of Units	Total MW	# of Units	Total MW	# of Units	Total MW	# of Units	Total MW	MW	Percent
Hydroelectric	45	887	7	315	26	348	2	11	1,562	5.0
Pumped Storage[4]	0	0	0	0	6	1,643	0	0	1,643	5.3
Nuclear	0	0	0	0	5	4,383	0	0	4,383	14.2
Fossil Steam - Oil	0	0	8	1,267	4	1,817	0	0	3,084	10.0
Fossil Steam - Coal	0	0	14	2,605	1	181	0	0	2,786	9.0
Fossil Steam - Dual Fuel	3	17	7	1,099	5	2,404	0	0	3,521	11.4
Steam - Bio/Refuse	0	0	0	0	29	751	9	189	940	3.0
Combined Cycle - Gas	0	0	0	0	0	0	21	6,520	6,520	21.1
Combined Cycle - Dual Fuel[5]	0	0	0	0	8	719	22	4,382	5,101	16.5
Gas Turbines - Jets	0	0	33	608	10	336	14	382	1,326	4.3
Internal Combustion	3	7	8	45	4	27	2	13	92	0.3
Totals	51	911	77	5,939	95	12,610	70	11,497	30,958	100.00
Percent of Total MW		2.9		19.2		40.7		37.1		

Does not include capacity purchased via the RFP for SWCT Emergency Capability or Settlement Only units.

[3]Unit in this table could stand for a power plant, not the individual units that may make up a power plant.

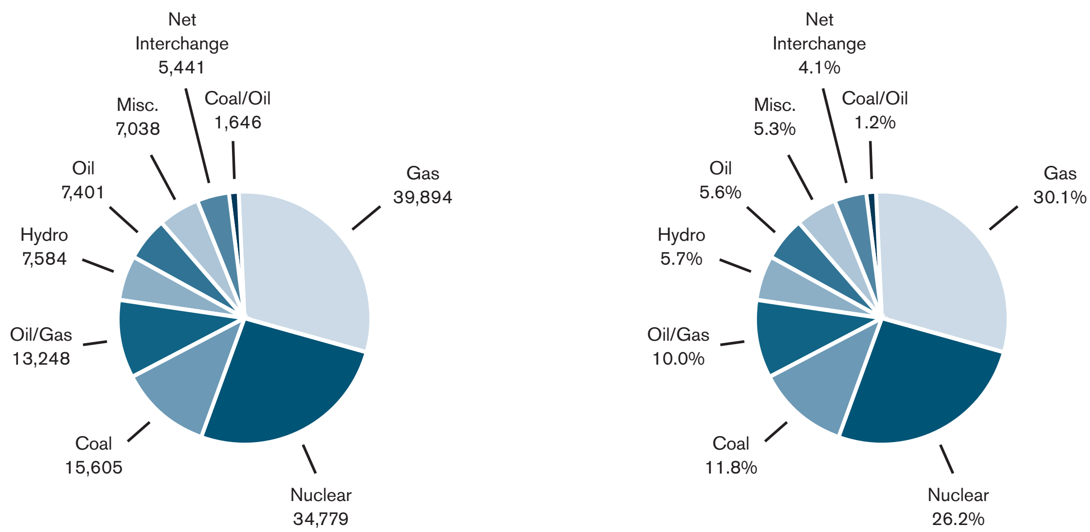
[4]The 29 MW Rocky River unit is classified as hydroelectric capacity in this table.

[5]Primary fuel may be gas or oil.

Figure 3.2 shows 2003 New England historical energy generation by fuel type, in megawatt hours (MWh) and percent. About 40 percent of energy was produced by gas-fired and dual fuel units with gas as the primary fuel. Roughly, 59 percent of energy generated in 2003 was from fossil-fueled units. Nuclear generation contributed approximately 26 percent of the total generation, while energy from hydro and miscellaneous resources was approximately 11 percent. Net energy interchange with neighboring Control Areas accounted for approximately 4 percent of total energy requirements.

FIGURE 3.2

2003 New England Annual Source of Energy in 1,000 MWh and Percent



Total = 132,636 MWh (1,000's)

Total = 100%

4.0 System Demand

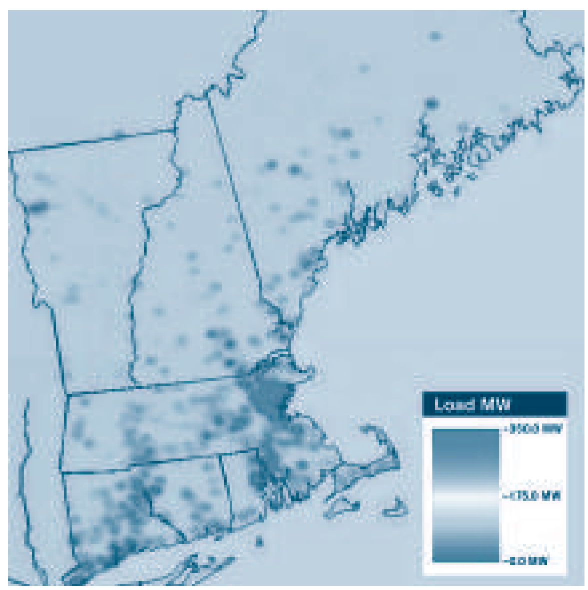
The New England power system is summer peaking. This means that the highest demand for power during the year typically occurs during the summer season. The projected system peak demand for 2004 was 25,735 MW under 50/50[6] weather conditions, and 27,305 MW under 90/10[7] weather conditions. In August 2002, the region reached an all-time record demand of 25,348 MW. The summer peak has increased by 20 percent over the last ten years and is expected to continue to grow by 15 percent over the next ten years. The projected winter peak demand for 2004/2005 is 22,370 MW under 50/50 weather conditions, or 23,255 MW under more severe 90/10 weather conditions. An all-time winter record demand of 22,817 MW was set on January 15, 2004. Both summer and winter peaks are expected to grow at a compound annual rate of 1.3 percent per year over the next ten years. Typical spring and fall peak demand ranges from 17,000 MW to 19,000 MW.

The forecasted system peak demands include estimated energy reductions from utility-sponsored demand-side management (energy conservation) and efficiency programs of approximately 1,535 MW in 2004, growing to approximately 1,565 MW by 2013.

Figure 4.1 indicates load concentrations on the New England system. The largest concentrations of load are in greater Boston, Southwestern Connecticut, and the mid-Connecticut River Valley. Smaller load centers appear near other cities throughout New England.

FIGURE 4.1

Load Concentrations in New England



[6]50/50 peak loads refer to loads that have a 50 percent chance of being exceeded due to weather conditions.

[7]90/10 peak loads refer to loads that have a 10 percent chance of being exceeded due to weather conditions.

5.0 System Analysis

Studies conducted for RTEP04 must be consistent with Planning Criteria and Procedures required by the North American Electric Reliability Council (NERC), Northeast Power Coordinating Council (NPCC), and New England Power Pool (NEPOOL). These include prescriptive guidelines for resource adequacy and transmission performance necessary to ensure reliable bulk electric power system design. The RTEP04 assumptions and analyses were reviewed with the TEAC and modified based on comments received.

Planning is a continuum, an ongoing effort as illustrated in Figure 5.1. It is impacted by various events captured through a wide variety of analyses, as summarized in the following section.

FIGURE 5.1

Planning Process

These analyses must all be considered to understand the complete view of power system performance. Each has individual merit and specific purposes, but no single analysis provides the overall picture. In order to determine overall system performance, the results of all studies must be reviewed from an integrated perspective.

5.1. Operable Capacity Analysis

Operable Capacity Analysis is a deterministic analysis of resource adequacy that is necessary to assess compliance with NPCC and NEPOOL criteria requiring consideration of both the 50/50 and 90/10 load forecast. This method essentially replicates the perspective of day-to-day operational requirements by identifying operable capacity requirements for the total system and by Sub-area[8], recognizing the specific characteristics of each area. The 90/10 forecast is used for load pockets as required by NERC, NPCC, and NEPOOL Planning Procedures, because isolated areas have limited transmission capability, few options for emergency actions, and the need to protect against situations that could cause cascading outages.

5.2. Loss of Load Expectation

Loss of Load Expectation (LOLE) is a probabilistic analysis of resource adequacy that is necessary to assess compliance with NPCC and NEPOOL criteria. The industry standard considers acceptable a loss, or disconnection, of load expectation of 0.1 days per year, or one day in ten years. ISO New England derives LOLE results from conducting probabilistic representations of both weekday peak demand and available resources taking into account a range of weather conditions and resource availability. This analysis utilizes a limited model of the transmission system and operational constraints but is extremely important because it identifies the amount of resources needed to meet the established resource planning reliability criterion.

5.3. Generation Duty Cycle

Generation Duty Cycle is an analysis of resource adequacy that will be used to identify the resource type and quantity needed to efficiently meet demand. The methodology is currently under development and will be addressed in RTEP05.

5.4. Economic Assessment

Economic Assessment analysis provides market information including future trends of resource costs, congestion, interface flows, and LMPs for various scenarios. Results are based on assumptions relating to fuel price forecasts, bidding practices, unit additions and retirements, unit availability

[8]Sub-areas are smaller subsets of the system modeled in simulations to reflect assumed static transmission constraints.

performance, transmission expansion, and others. To conduct this assessment, ISO New England uses a deterministic assessment of 50/50 forecast load based on the NEPOOL 2004-2013 Forecast Report of Capacity, Energy, Loads, and Transmission (CELT).

5.5. Fuel Diversity

With the region's high dependency on natural gas, RTEP04 examined the reliability risks of fuel shortages by calculating the LOLE and the unserved energy for various fuel shortage scenarios. The status of natural gas and expanding liquefied natural gas (LNG) supply in the Northeast is summarized. The efforts by ISO New England and the natural gas industry to prepare for future "cold snaps" are summarized.

5.6. Air Emissions Issues

RTEP04 includes results of simulations for the region's electric production air emission over the next ten years. The emissions are SO_2, NO_x and CO_2. The simulations were done for various generation and transmission scenarios.

5.7. Transmission Studies

Transmission studies are necessary to ensure that reliability can be maintained in conformance with NERC, NPCC, and NEPOOL criteria. These studies are also conducted to evaluate the performance of economic, elective, and merchant transmission upgrades. ISO New England utilizes a comprehensive model of the power system that includes all generators, transmission facilities, and loads. Simulations address physical issues such as thermal loading, minimum voltage, voltage regulation, transient stability, dynamic oscillations, harmonics, and short circuit interrupting capability.

5.8. RTEP Sub-areas

New England is a tightly integrated system; therefore, ISO New England analyzes and plans for the reliability and adequacy of the New England bulk electric power system as an integrated whole. To accomplish this, simulations of the system under various conditions are conducted to examine corresponding impacts. However, in some of the RTEP analyses, ISO New England employs smaller subsets of the system, or Sub-areas, as a tool to accommodate certain system models.

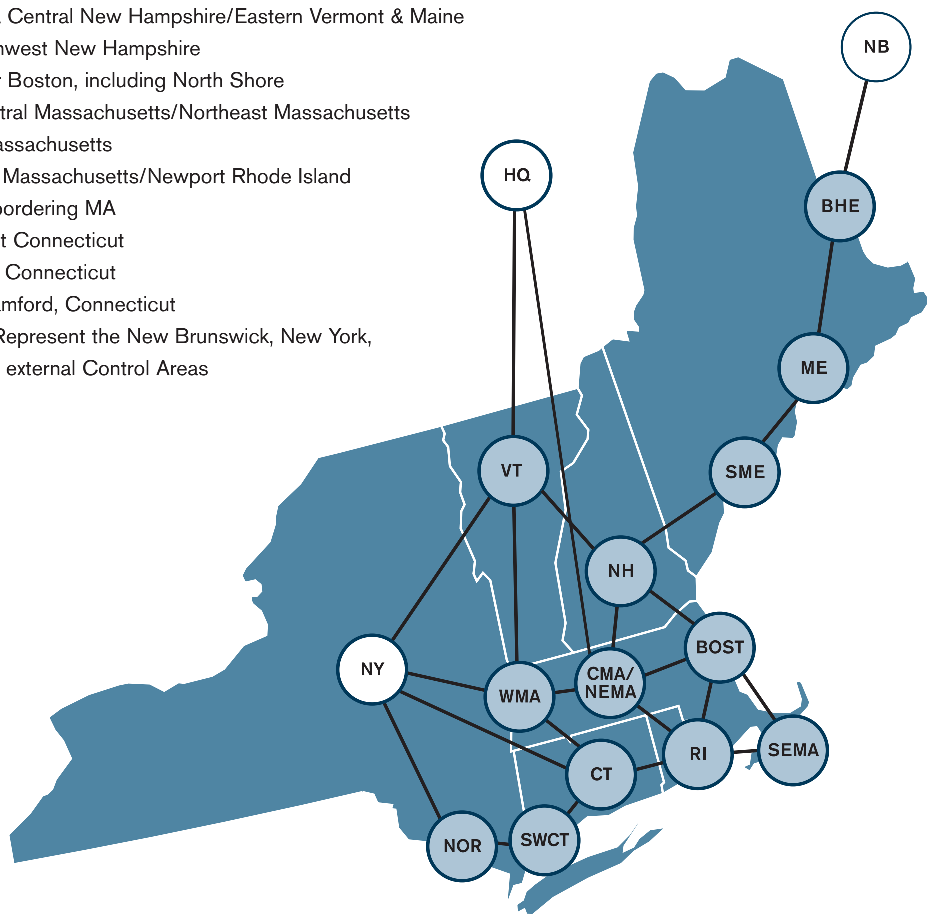
Figure 5.2 represents the Sub-areas employed by RTEP in the transportation model-based analyses that are a simplified representation of potential major transmission limitations. Figure 5.3 is a representation of the high voltage transmission system in New England, as provided in the CELT Report. The CELT 04 map includes potential transmission upgrades through 2013 that are still under study and may or may not actually be constructed. The Figure is provided to illustrate the difference in complexity between the "real world" system and the relatively simple representation of the RTEP Sub-areas shown in Figure 5.2.

FIGURE 5.2

RTEP Geographic Scope

The 13 RTEP Sub-areas and the three external control areas shown in Figure 5.2 are designated:

BHE - Northeast Maine
ME - Western & Central Maine/Saco Valley, New Hampshire
SME - Southeast Maine
NH - North, East, & Central New Hampshire/Eastern Vermont & Maine
VT - Vermont/Southwest New Hampshire
BOSTON - Greater Boston, including North Shore
CMA/NEMA - Central Massachusetts/Northeast Massachusetts
WMA - Western Massachusetts
SEMA - Southeast Massachusetts/Newport Rhode Island
RI - Rhode Island/bordering MA
CT - North and East Connecticut
SWCT - Southwest Connecticut
NOR - Norwalk/Stamford, Connecticut
NB, NY and **HQ** - Represent the New Brunswick, New York, and Hydro-Quebec external Control Areas



As can be seen, the RTEP Sub-areas constitute a considerable simplification of the actual transmission network. The results of the transportation analyses of these Sub-areas do not capture system constraints within the Sub-areas, but rather reflect transfer capabilities between them. As such, transportation modeling results based on the Sub-areas should be considered "best-case" results. While suitable for the resource reliability and economic assessments presented in the RTEP Technical Report, detailed transmission analyses are essential to more accurately capture system performance within and between the RTEP Sub-areas. For purposes of assessing system performance, the more detailed transmission analyses are indifferent to the RTEP Sub-area definitions.

Moreover, the RTEP Sub-areas do not directly coincide with the SMD load zones, which have been established for market settlement purposes. The RTEP Sub-area loads are comprised of portions of the New England states and SMD load zones as shown in Table 5.1.

TABLE 5.1

RTEP Sub-areas, the New England States, and SMD Load Zones[9]

RTEP Sub-area	SMD Load Zone	State	2004 Summer Peak Load Forecast 50/50 MW	50/50 Percent of RTEP Sub-area	50/50 Percent of State Peak Load	90/10 MW	90/10 Percent of RTEP Sub-area	90/10 Percent of State Peak Load
BHE: Northeast Maine			**300**			**310**		
	ME	ME	300	100	15.6	310	100	15.5
ME: Western & Central Maine / Saco Valley New Hampshire			**970**			**1,010**		
	ME	ME	921	94.9	47.9	957	94.7	47.9
	NH	NH	49	5.1	2.2	53	5.3	2.2
SME: Southeast Maine			**660**			**685**		
	ME	ME	660	100	34.3	685	100	34.4
NH: North, East, & Central New Hampshire / Eastern Vermont & Maine			**1,680**			**1,810**		
	ME	ME	42	2.5	2.2	44	2.4	2.2
	NH	NH	1,567	93.3	70.6	1,691	93.5	70.7
	VT	VT	71	4.2	6.8	75	4.1	6.9
VT: Vermont & Southwest New Hampshire			**1,260**			**1,340**		
	NH	NH	374	29.7	16.9	405	30.3	16.9
	VT	VT	886	70.3	86	935	69.7	86
BOSTON: Greater Boston including North Shore			**5,310**			**5,620**		
	NEMA/Boston	MA	5,230	98.5	44.2	5,535	98.5	44.2
	NH	NH	80	1.5	3.6	85	1.5	3.6
CMA/NEMA: Central & Merrimack Valley Massachusetts			**1,700**			**1,810**		
	West/Cent MA	MA	1,553	91.3	13.1	1,650	91.2	13.2
	NH	NH	147	8.7	6.7	160	8.8	6.7
WMA: Western Massachusetts			**1,980**			**2,100**		
	Connecticut	CT	68	3.4	1	72	3.4	1
	West/Cent MA	MA	1,839	92.9	15.6	1,950	92.9	15.6
	VT	VT	73	3.7	7.1	78	3.7	7.2
SEMA: Southeast Massachusetts & Newport, Rhode Island			**2,620**			**2,780**		
	Southeast MA	MA	2,480	94.7	21	2,631	94.6	21
	RI	RI	140	5.3	8	149	5.4	8
RI: Rhode Island & bordering Massachusetts			**2,345**			**2,490**		
	Southeast MA	MA	717	30.6	6	764	30.7	6.1
	RI	RI	1,628	69.4	92	1,726	69.3	92
CT: North & East Connecticut			**3,420**			**3,640**		
	Connecticut	CT	3,420	100	49	3,640	100	49
SWCT: Southwest Connecticut			**2,245**			**2,390**		
	Connecticut	CT	2,245	100	32.1	2,390	100	32.1
NOR: Norwalk/Stamford, Connecticut			**1,250**			**1,330**		
	Connecticut	CT	1,250	100	17.9	1,330	100	17.9

[9] Sum may not equal total due to rounding.

Table 5.2 shows the total installed capacity by RTEP Sub-area and does not account for forced outages or transmission-constrained generation (sometimes referred to as bottled generation). The table also identifies the fuel mix of generation capacity by RTEP Sub-area. As can be seen from the table, a number of RTEP Sub-areas are highly dependent upon gas-fired generation, notably the import-constrained Sub-areas of BOSTON and SWCT.

TABLE 5.2

NEPOOL Sub-area Installed Summer Generating Capacity Mix by Primary Fuel Type (MW & Percent[10])

Area	BHE		ME		SME		NH		BOSTON		SEMA		CMA/NEMA	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Nuclear	0	0.0	0	0.0	0	0.0	1,159	29.6	0	0.0	685	20.4	0	0.0
Coal	0	0.0	0	0.0	0	0.0	575	14.7	311	8.7	106	3.1	0	0.0
Gas	659	74.0	373	41.3	512	33.9	1,140	29.1	1,606	44.9	1,214	36.2	101	62.7
Oil	19	2.1	0	0.0	860	57.1	485	12.4	1,547	43.3	1,277	38.1	0	0.0
Hydro	110	12.3	349	38.6	62	4.1	438	11.2	9	0.3	0	0.0	20	12.5
Pumped Storage	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Misc.	103	11.6	181	20.1	73	4.9	115	2.9	100	2.8	72	2.2	40	24.8
Total	890	100.0	903	100.0	1,507	100.0	3,912	100.0	3,573	100.0	3,353	100.0	160	100.0

Area	WMA		RI		CT		SWCT		NOR		VT	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Nuclear	0	0.0	0	0.0	2,033	46.3	0	0.0	0	0.0	506	58.2
Coal	145	3.9	1,096	21.3	181	4.1	372	17.5	0	0.0	0	0.0
Gas	1,027	27.9	3,548	69.1	93	2.1	1,271	59.8	0	0.0	0	0.0
Oil	618	16.8	478	9.3	1,937	44.1	370	17.4	396	87.0	95	10.9
Hydro	246	6.7	0	0.0	26	0.6	106	5.0	0	0.0	197	22.6
Pumped Storage	1,643	44.6	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Misc.	6	0.2	12	0.2	121	2.8	6	0.3	59	13.0	73	8.3
Total[11]	3,685	100.0	5,133	100.0	4,392	100.0	2,126	100.0	456	100.0	870	100.0

The modeling of the New England region and its Sub-areas is dependent upon a variety of assumptions regarding new unit in-service dates, generation availabilities, fuel costs, timing of transmission upgrades, load forecasts, and transactions with neighboring Control Areas. A major part of the annual RTEP process includes an updating of the modeling assumptions used to reflect changed circumstances.

[10]May not equal sum due to rounding.

[11]The total may add to more than 30,958 due to rounding.

6.0 Resource Reliability Assessment

The Resource Reliability Assessment encompasses analyses that address system needs for meeting operable capacity and LOLE requirements. RTEP04 also identifies the amount and location of required resources in critical need areas of the system.

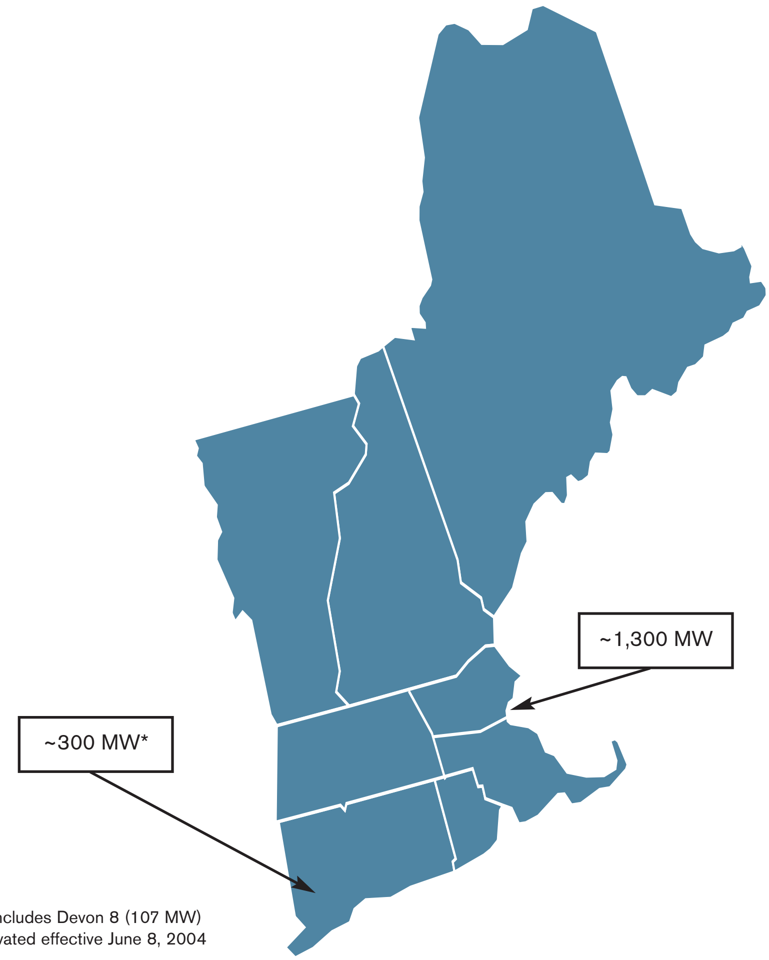
6.1. Operable Capacity Analysis

Operable Capacity Analysis examines the margin between available resources and expected load plus required operating reserves that provide coverage for the contingency loss of the largest facility. A negative margin indicates that special steps, as defined in Operating Procedure No. 4 – Action During a Capacity Deficiency (OP 4), must be taken by the system operator to reestablish required operating reserves. Depending on the amount of negative margin, these procedures could call for the interruption of load, a very serious action. A negative margin can also be used to identify the capacity needs of an area of the system.The generating unit ratings used in the Operable Capacity Analysis are based on the ISO New England April 2004 Seasonal Claimed Capability Report.

An operable capacity margin is made worse by generation attrition or outages. Risk categories that could result in generation attrition or outages include the age of units, new environmental requirements, and financial pressures that might result in a lack of necessary preventative maintenance and a lack of fuel diversity. Approximately 1,600 MW have already requested retirement or deactivation but have mostly been denied. Figure 6.1 shows the location and amounts of these requests for deactivation or retirements. The following sections discuss operable capacity results for all of New England as well as for the critical Sub-areas.

FIGURE 6.1

18.4 Requests for Retirement/Deactivation as of August 2004 – Summer MW



*300 MW value includes Devon 8 (107 MW) which was deactivated effective June 8, 2004

6.1.1. New England Overall

Figure 6.2 and Table 6.1 show that New England could experience a negative operable capacity margin as early as summer of 2006 if the loads associated with hot and humid weather (94 degrees F and above) occur, the assumed amount of generation outages materialize, and no new resources are added. Without the installation of new resources, this negative operable capacity margin would get progressively worse as load grows. Short-term measures to mitigate this need include firm purchases from neighboring systems, use of resources acquired through the Request for Proposal (RFP) for

Southwest Connecticut Emergency Capability, and emergency actions. In the longer term, market incentives will be provided to encourage the development of resources.

Meriden and Kleen Energy are the only two major generator projects on the planning horizon that have 18.4 approval. If these projects were to start construction this year, they could conceivably be in service by 2007. Together they would add over 1,100 MW and cover the capacity deficiency until around 2009. Investment in new generation resources such as these two projects will depend on a functioning Locational ICAP market.

FIGURE 6.2

Projected New England Capacity Situation – Summer 2004-2013 Using 90/10 Loads

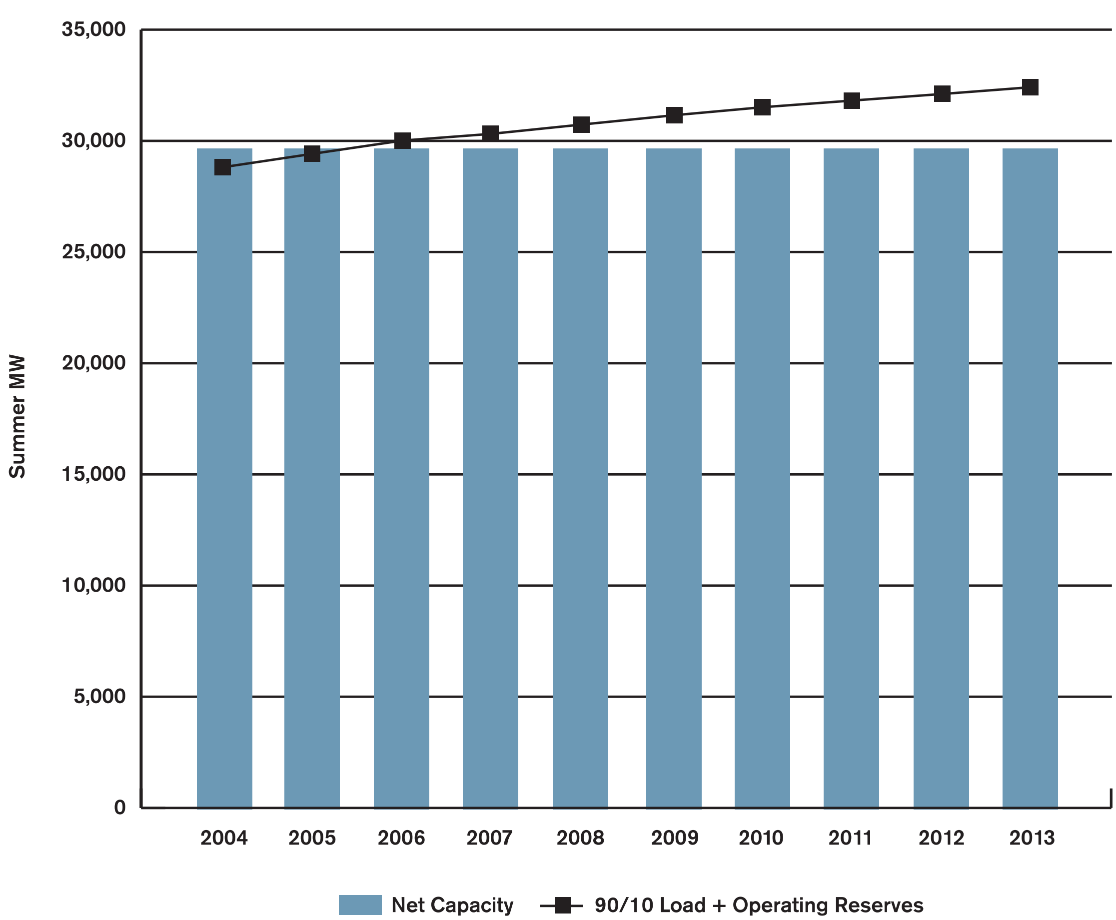


TABLE 6.1

Projected New England Capacity Situation – Summer (MW) 2004-2013 using 90/10 Loads

Capacity Situation (Summer MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Load (90/10 Forecast)	27,305	27,935	28,220	28,485	28,770	29,090	29,460	29,915	30,315	30,660
Reserves	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700	1,700
Total Requirement	29,005	29,635	29,920	30,185	30,470	30,790	31,160	31,615	32,015	32,360
Capacity[12]	31,764	31,764	31,764	31,764	31,764	31,764	31,764	31,764	31,764	31,764
Assumed Unavailable Capacity	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Total Net Capacity	29,764	29,764	29,764	29,764	29,764	29,764	29,764	29,764	29,764	29,764
Total Available Resources	29,764	29,764	29,764	29,764	29,764	29,764	29,764	29,764	29,764	29,764
Available Surplus/(Deficiency)	759	129	(156)	(421)	(706)	(1,026)	(1,396)	(1,851)	(2,251)	(2,596)

Note: The figures above reflect no generation unit additions, retirements, or deactivations.

Although New England is a summer peaking system, the winter season presents some risk to the region's reliability. On January 14, 15, and 16, 2004, a cold snap resulted in many generating units being out-of-service due to cold weather and unavailability of gas units. This placed the system at greater risk of loss of load, and it was necessary to implement OP 4 on January 14, in order to mitigate a deficit of approximately 100 MW. To avoid or mitigate such potential capacity shortages in future winter periods, ISO New England and market participants took the following actions that will result in up to 2,000 MW of capacity beyond that available during the January 2004 Cold Snap:

> Establishment of an Electric/Gas Operations Committee (EGOC) to improve near-term operations planning and coordination of maintenance of both the electric and gas pipeline systems in anticipation of cold snap conditions. Communication protocols will be consistent with the NEPOOL Information Policy.

[12]The amount of capacity assumed in the deterministic Operable Capacity Analysis is based on the April 2004 Seasonal Claimed Capability Report, which reflects 30,909 MW of installed generating resource in New England claimed for capability, 255 MW of "settlement only" capacity, and 600 MW of assumed firm imports.

- Development of a new Operating Procedure for cold snap periods that would trigger:

    1. Elimination or cancellation of "Economic Outages."

    2. Efficient switching to alternative fuels for dual fueled units.

    3. Modification of unit commitment processes to enhance coordination between the electric and gas market nomination timelines.

6.1.2. Load Pockets

In addition to the overall New England Operable Capacity Analysis, key problem areas or load pockets have been analyzed. The results for these areas follow.

6.1.2.1. Southwestern Connecticut

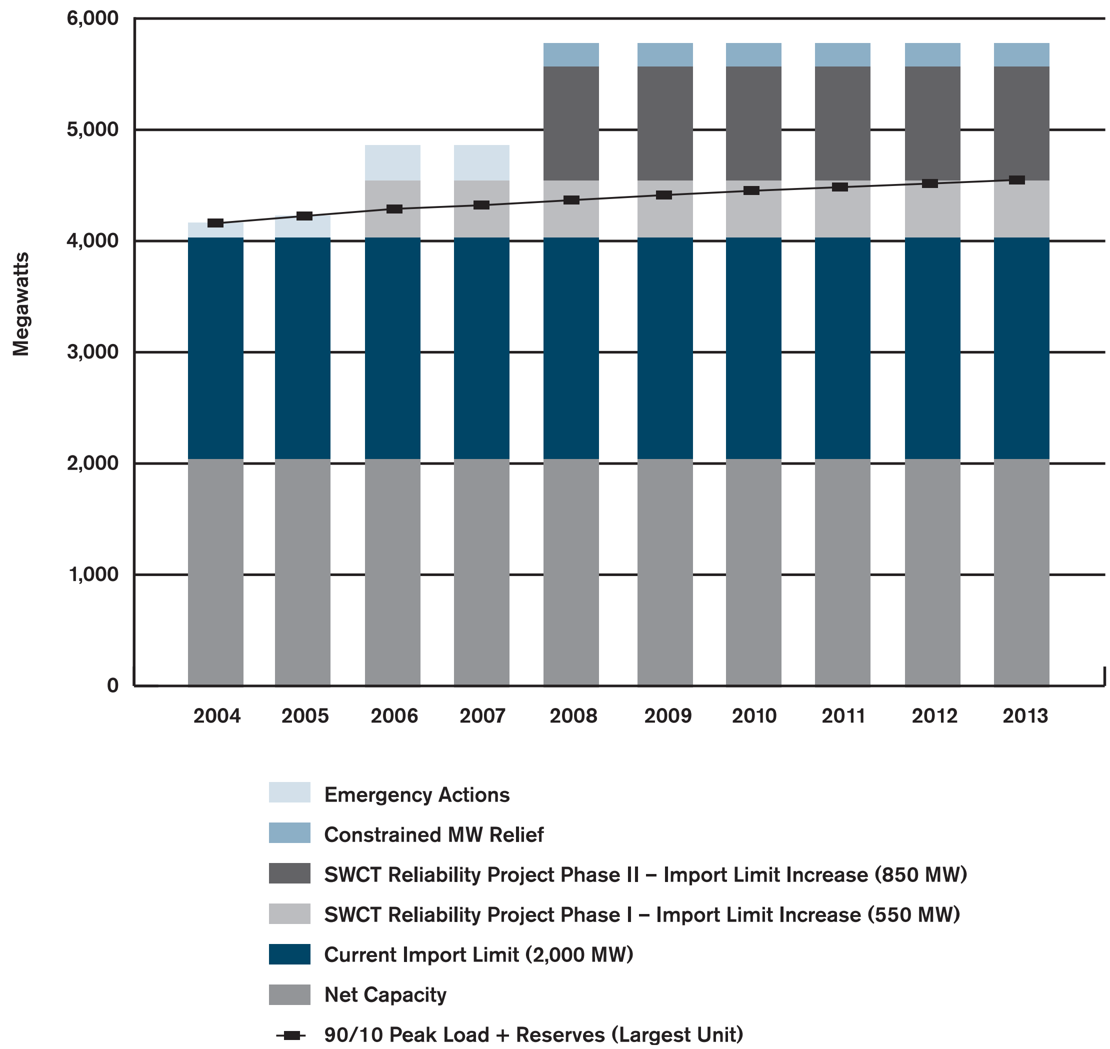
Figure 6.3 and Table 6.2 indicate that without emergency actions, Southwestern Connecticut (SWCT and NOR Sub-areas) will be short of capacity to meet the 90/10 summer peak load forecast plus operating reserve until the proposed Southwest Connecticut Reliability Project is in service. Study results project a shortfall of 130 MW in Southwestern Connecticut in 2004, which increases to approximately 270 MW by year 2007. Based on these results, demand response and emergency capacity resources purchased via the RFP for Southwest Connecticut Emergency Capability will help bridge the resource gap until the proposed transmission upgrades are in service. The Southwest Connecticut Reliability Project will provide adequate import capability to meet load and reserve requirements and will accommodate generation expansion plans consisting of repowering of existing units, as well as construction of new units, within Southwestern Connecticut beginning in 2008. Significant delays in the transmission upgrades may result in:

- A serious shortfall of required resources necessary to ensure reliability. Only a total of 50-100 MW of quick-start peaking or emergency generation can be installed in Southwestern Connecticut and limited sites are available in Southwestern Connecticut due to transmission limitations.

- A need for demand response and conservation, which are likely the most viable resources to cover a long delay.

FIGURE 6.3

Projected Capacity Situation in Southwestern Connecticut – Summer (MW)



Notes: Constrained MW relief is generating capacity that will be "unbottled" with the implementation of the SWCT Reliability Phase I and Phase II 345 kV projects (223 MW).

Emergency action is the RFP for SWCT Emergency Capability response assumed to expire after 2007.

TABLE 6.2

Projected Capacity Situation in Southwestern Connecticut
90/10 Peak Loads – Summer MW

Capacity Situation (Summer MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Load (90/10 Forecast)	3,720	3,795	3,830	3,855	3,890	3,935	3,985	4,040	4,095	4,145
Reserves (Largest Unit)	450	450	450	450	450	450	450	450	450	450
Total Requirement	4,170	4,245	4,280	4,305	4,340	4,385	4,435	4,490	4,545	4,595
Capacity	2,567	2,567	2,567	2,567	2,567	2,567	2,567	2,567	2,567	2,567
Assumed Unavailable Capacity	529	529	529	529	529	529	529	529	529	529
Total Net Capacity	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038	2,038
Current Import Limit	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
Total Available Resources	4,038	4,038	4,038	4,038	4,038	4,038	4,038	4,038	4,038	4,038
Available Surplus/(Deficiency)	(132)	(207)	(242)	(267)	(302)	(347)	(397)	(452)	(507)	(557)
Possible Unit Additions										
Constrained Generation	-	-	-	-	223	223	223	223	223	223
Total Additions	-	-	-	-	223	223	223	223	223	223
Available Surplus/(Deficiency) After Assumed Additions	(132)	(207)	(242)	(267)	(79)	(124)	(174)	(229)	(284)	(334)
Identified Actions (Summer MW)	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Strengthening of System										
SWCT Reliability Project Phase I (Increase to SWCT Import Limit)	-	-	550	550	550	550	550	550	550	550
SWCT Reliability Project Phase II (Increase to SWCT Import Limit)	-	-	-	-	850	850	850	850	850	850
Southern New England Reinforcement Project (Increase to SWCT Import Limit)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Emergency Actions										
RFP for SWCT Emergency Capability (Award)	125	218	250	256	-	-	-	-	-	-
Operating Procedure (Emergency Load Swap)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total Identified Actions After All Additions/Retirements/ Deactivations Identified Actions	125	218	800	806	1,400	1,400	1,400	1,400	1,400	1,400
Available Surplus/(Deficiency)	(7)	11	558	539	1,321	1,276	1,226	1,171	1,116	1,066

Notes: Capacity values based on April 2004 Seasonal Claimed Capability Report Ratings.

Assumed unavailable capacity is made up of 174 MW of Forced Outages (6.78 percent of Capacity), 223 MW of constrained generation (goes away with assumed in-service of SWCT Reliability Project Phase II in 2008), and 132 MW of peaking unit deratings.

6.1.2.2. Connecticut

Figure 6.4 and Table 6.3 indicate that without Emergency Actions, the State of Connecticut[13] is expected to be short of generating capacity to meet the 90/10 forecast peak load plus operating reserve through 2013. The deficiency could range from approximately 420 MW in 2004 to about 1,265 MW in 2013. The emergency capacity purchased through the RFP for SWCT Emergency Capability through 2007, and the estimated 340 MW of emergency load swap from Connecticut to Western Massachusetts, would provide mitigating relief. The emergency load swap is achieved through switching operations that reconfigure the network such that some Connecticut load is radially served from Western Massachusetts. This action results in less reliable service to that load. Pending further transmission analysis, the long-term sustainability of the emergency load swap may not be feasible as load grows in the Springfield, Massachusetts area.

The proposed Phase II of the Southwest Connecticut Reliability Project, targeted for completion in 2008, would release approximately 220 MW of constrained generation within Southwestern Connecticut. The proposed Southern New England Reinforcement Project, assumed to be in service in 2008, would eliminate the need for the special emergency load swap operating procedure. Subject to study confirmation, the project could potentially interconnect the 730 MW Lake Road generating units to Connecticut[14]. These units are currently electrically connected to Rhode Island. The Southern New England Reinforcement Project would also increase the import capability into Connecticut by 800 MW to 1,000 MW[15], thus eliminating the capacity shortfall during the study period. However, even if the necessary transmission is built on schedule, load growth dictates a tight window to accommodate new capacity that could include the repowering of existing generation sites.

The Connecticut situation requires timely completion of the Southern New England Reinforcement Project. A delay would result in the following:

> Continuation of the tight capacity problem in Connecticut. Lacking transmission improvements, the state would need to depend on the resources obtained from the RFP for SWCT Emergency Capability and an undesirable emergency load swap procedure.

> Requirement of additional resources through the planning period within Connecticut, possibly through generator development or demand response.

> Identification and implementation of alternative system improvements to bring additional resources into Connecticut. For example, transmission could be reconfigured to electrically bring one or more of the Lake Road units into Connecticut.

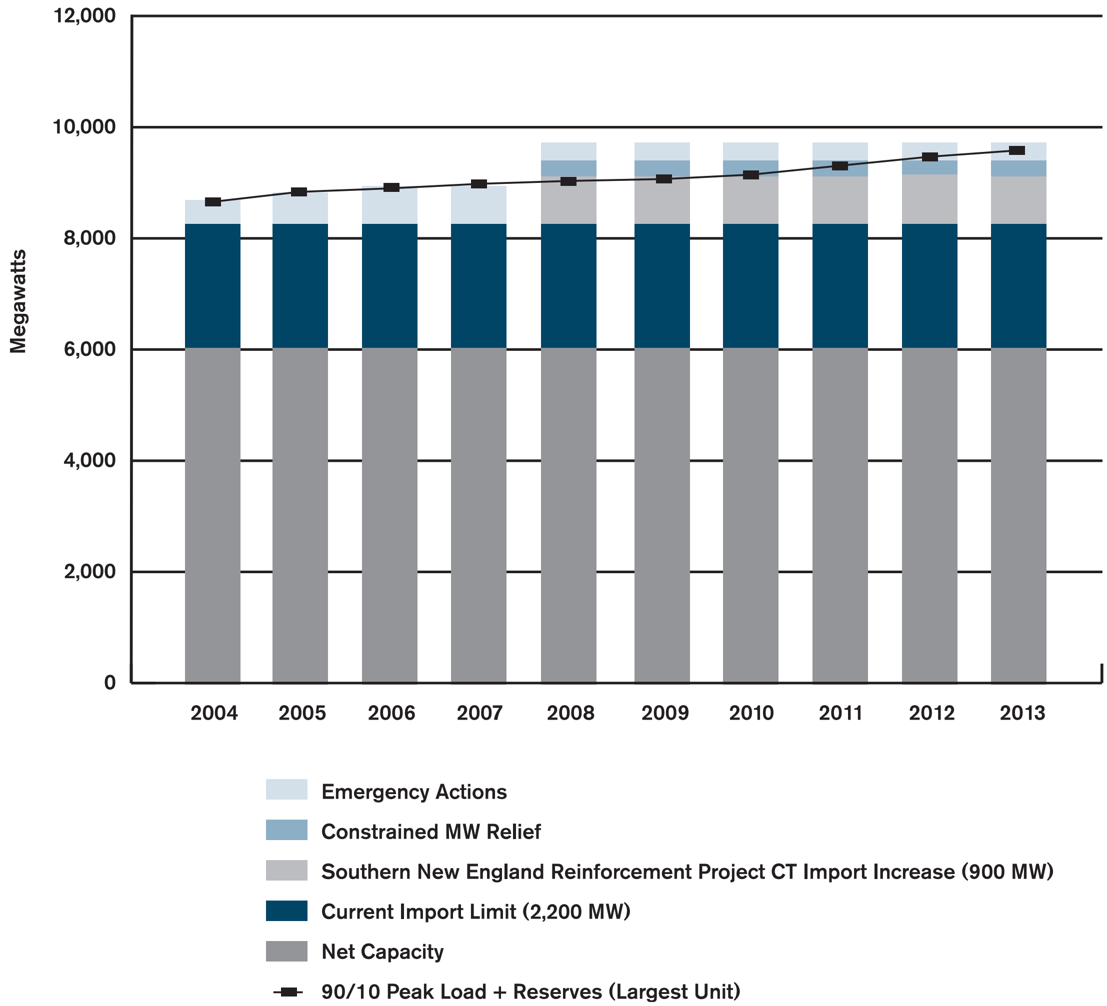
[13]The State of Connecticut load includes the NOR, SWCT, and CT Sub-areas plus some load in WMA.

[14]The Lake Road Generating Unit is physically in the State of Connecticut but electrically in the Rhode Island Sub-area. Until studies are complete, a 0 MW benefit is assumed.

[15]The increase in Figure 6.4 is 900 MW for the Southern New England Reinforcement Project.

FIGURE 6.4

Projected Capacity Situation in State of Connecticut – Summer (MW)



Notes: Emergency actions are: 1. RFP for SWCT Emergency Capability response.
2. Emergency load swap from Connecticut to Western Massachusetts (340 MW).

Constrained MW relief is generating capacity that will be “unbottled” with the implementation of the SWCT Reliability Project Phase I and Phase II 345 kV (223 MW).

TABLE 6.3

Projected Capacity Situation in the State of Connecticut 90/10 Peak Loads – Summer MW

Capacity Situation (Summer MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Load (90/10 Forecast[16])	7,435	7,575	7,645	7,690	7,790	7,840	7,940	8,060	8,180	8,280
Reserves (Largest Unit)	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Total Requirement	8,635	8,775	8,845	8,890	8,990	9,040	9,140	9,260	9,380	9,480
Capacity	6,927	6,927	6,927	6,927	6,927	6,927	6,927	6,927	6,927	6,927
Assumed Unavailable Capacity	912	912	912	912	912	912	912	912	912	912
Total Net Capacity	6,015	6,015	6,015	6,015	6,015	6,015	6,015	6,015	6,015	6,015
Current Import Limit	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200	2,200
Total Available Resources	8,215	8,215	8,215	8,215	8,215	8,215	8,215	8,215	8,215	8,215
Available Surplus/(Deficiency)	(420)	(560)	(630)	(675)	(775)	(825)	(925)	(1,045)	(1,165)	(1,265)
Possible Unit Additions										
Constrained Generation	0	0	0	0	223	223	223	223	223	223
Millstone 2 Uprate	16	16	16	16	16	16	16	16	16	16
Total Additions	16	16	16	16	239	239	239	239	239	239
Available Surplus/(Deficiency) After Assumed Additions	(404)	(544)	(614)	(659)	(536)	(586)	(686)	(806)	(926)	(1,026)
Identified Actions (Summer MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Strengthening of System										
SWCT Reliability Project Phase I (Increase to CT Import Limit)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
SWCT Reliability Project Phase II (Increase to CT Import Limit)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Southern New England Reinforcement Project (Increase to CT Import Limit)	0	0	0	0	800-1,000	800-1,000	800-1,000	800-1,000	800-1,000	800-1,000
Emergency Actions										
RFP for SWCT Emergency Capability (Award)	125	218	250	256	0	0	0	0	0	0
Operating Procedure (Emergency Load Swap)	340	340	340	340	340	340	340	340	340	340
Total Identified Actions	465	558	590	596	1,140-1,340	1,140-1,340	1,140-1,340	1,140-1,340	1,140-1,340	1,140-1,340
After All Additions/Retirements/ Deactivations Identified Actions										
Available Surplus/(Deficiency)	61	14	(24)	(63)	604-804	554-754	454-654	334-534	214-414	114-314

Notes: Capacity values based on April 2004 Seasonal Claimed Capability Report Ratings.

Assumed unavailable capacity is made up of 470 MW of Forced Outages (6.78 percent of Capacity), 223 MW of constrained generation (goes away with assumed in-service of SWCT Reliability Project Phase II in 2008), and 219 MW of peaking unit deratings.

Millstone 2 uprate increase based on difference between April 2004 Seasonal Claimed Capability report capacity rating and anticipated increase.

[16]These are loads for the State of Connecticut. They are different than summing the loads of the RTEP Sub-areas of NOR, SWCT and CT.

6.1.2.3. BOSTON

The BOSTON Sub-area has adequate operable capacity in the short term. However, new transmission infrastructure is required to improve interrelated reliability problems, including:

> Limited access to regional supplies because of import restrictions into the BOSTON area.

> Dependency on over 1,300 MW of generation which has the possibility of retiring.

> Inability to import power into separate load pockets in Downtown Boston and the North Shore.

> Vulnerability to outages possibly caused by fuel interruptions because about 45 percent of the generation in the BOSTON Sub-area is fueled by natural gas, a dependency that raises additional concerns.

> Reliance on up to 400 MW of emergency load shedding for the second contingency outage of a transmission facility.

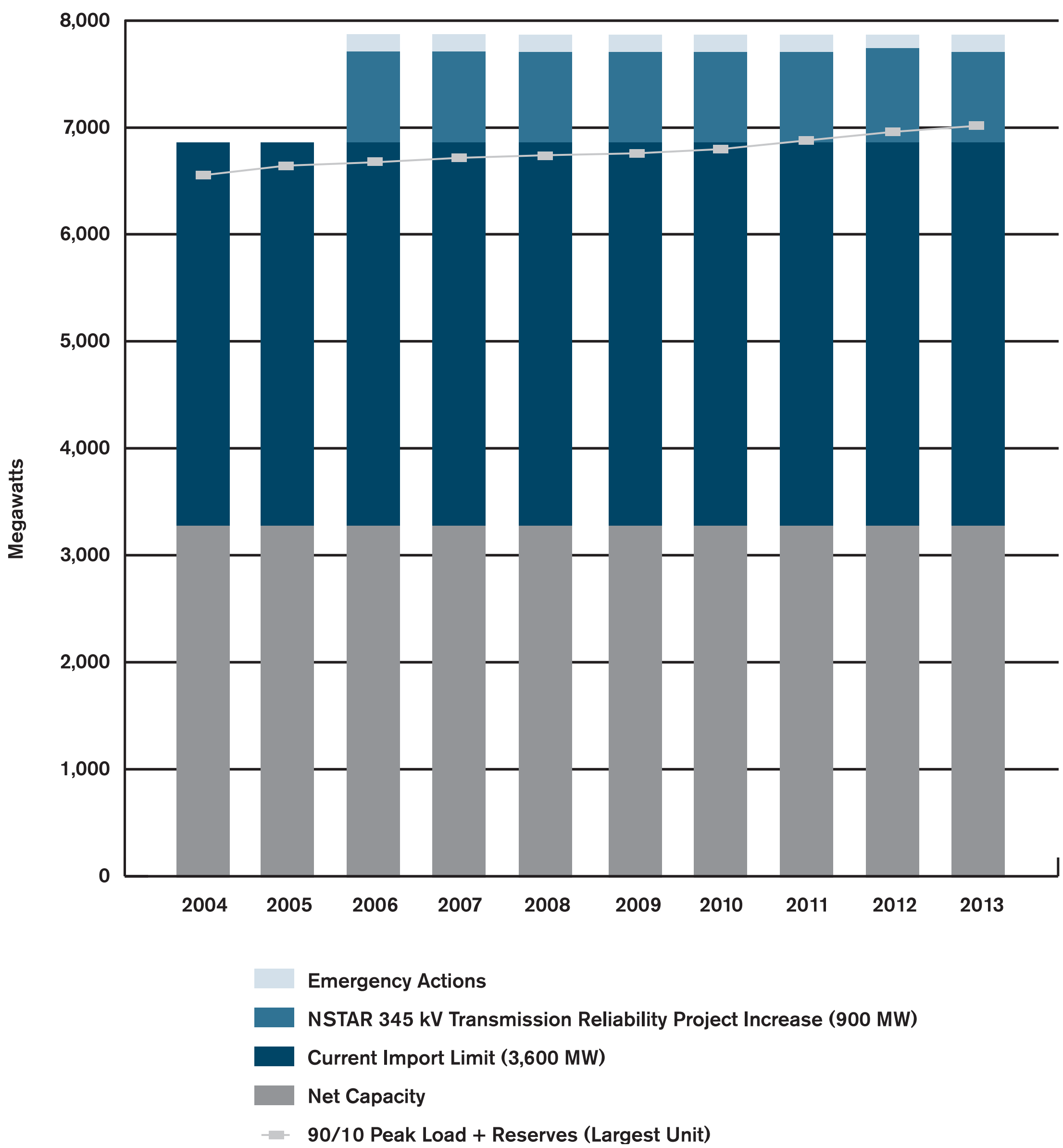
Figure 6.5 and Table 6.4 demonstrate the projected capacity situation in the BOSTON Sub-area. The table illustrates that load growth, coupled with unit retirements or deactivations and a delay in the NSTAR project, could cause serious problems in reliability for this Sub-area. The NSTAR 345 kV Transmission Reliability Project and North Shore Upgrades would ensure overall system reliability, including the requirements of the downtown Boston and North Shore areas. These upgrades would facilitate the repowering of existing sites and/or the interconnection of new generating resources in the BOSTON Sub-area. The NSTAR 345 kV Transmission Reliability Project, timed for 2006, would also increase the import limit into BOSTON by approximately 900 MW.

As shown in Table 6.4, the completion of the NSTAR 345 kV Transmission Reliability Project by 2006 would provide additional transfer capability to import operable capacity to BOSTON. This results in adequate capacity even with unit deactivations and retirements at Kendall and New Boston stations. However, a delay of the project would require the continued service of New Boston, and necessitate by 2008 either the reactivation of Kendall Steam Turbine 1 and the Kendall Combustion Turbine, or the addition of new resources. Even with all potentially retired units at Kendall and New Boston remaining in service, load growth would require the addition of new capacity in the BOSTON Sub-area by 2011/12.

The situation is further complicated by the need to preserve all Salem Harbor units until the North Shore Upgrades are completed. Any subsequent deactivation or retirement of Salem Harbor units would place additional dependency on imports into the BOSTON Sub-area and advance the need for new capacity.

FIGURE 6.5

Projected Capacity Situation in BOSTON – Summer (MW)



Notes: Emergency action includes a load swap of approximately 50 MW out of the BOSTON Sub-area to the Northeast Massachusetts Sub-area (CMA/NEMA).

TABLE 6.4

Projected Capacity Situation in Boston 90/10 Peak Loads – Summer MW

Capacity Situation (Summer MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Load (90/10 Forecast)	5,620	5,765	5,830	5,900	5,965	6,030	6,105	6,200	6,270	6,330
Reserves (Largest Unit)	710	710	710	710	710	710	710	710	710	710
Total Requirement	6,330	6,475	6,540	6,610	6,675	6,740	6,815	6,910	6,980	7,040
Capacity	3,602	3,602	3,602	3,602	3,602	3,602	3,602	3,602	3,602	3,602
Assumed Unavailable Capacity	326	326	326	326	326	326	326	326	326	326
Total Net Capacity	3,276	3,276	3,276	3,276	3,276	3,276	3,276	3,276	3,276	3,276
Imports	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600	3,600
Total Available Resources	6,876	6,876	6,876	6,876	6,876	6,876	6,876	6,876	6,876	6,876
Available Surplus/(Deficiency)	546	401	336	266	201	136	61	(34)	(104)	(164)
Assumed Unit Retirements										
Kendall Steam 1 (18 MW)	-	18	18	18	18	18	18	18	18	18
Kendall Steam 2 (21 MW)	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
Kendall Steam 3 (24 MW)	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
Kendall Combustion Turbine (154 MW)	-	154	154	154	154	154	154	154	154	154
Kendall Jet 1 (17 MW)	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
Kendall Jet 2 (15 MW)	-	15	15	15	15	15	15	15	15	15
New Boston (350 MW)	-	-	350	350	350	350	350	350	350	350
Salem Harbor 1-4 (705 MW)	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown	Unknown
Total Capacity Retirements/Deactivations	-	187	537	537	537	537	537	537	537	537
Available Surplus/(Deficiency) After Retirements/Deactivations	546	214	(201)	(271)	(336)	(401)	(476)	(571)	(641)	(701)
Identified Actions (Summer MW)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Strengthening of System										
NSTAR 345 kV Transmission Reliability Project	-	-	900	900	900	900	900	900	900	900
Emergency Actions										
Operating Procedure (Emergency Load Swap)	50	50	50	50	50	50	50	50	50	50
Total Identified Actions	50	50	950	950	950	950	950	950	950	950
After All Additions/Retirements/ Deactivations Identified Actions										
Available Surplus/(Deficiency)	596	264	749	679	614	549	474	379	309	249

Notes: Assumed unavailable capacity is made up of 244 MW of Forced Outages (6.78 percent of Capacity) and 82 MW of peaking unit deratings.

Capacity values based on April 2004 Seasonal Claimed Capability Report Ratings.

Kendall Steam 1 assumed deactivated based on 6/22 RC meeting vote where one of the three Kendall Steam units were approved to deactivate (no specifics on which of three were to go).

Kendall Combustion Turbine assumed deactivated based on 6/22 RC meeting vote to approve application

Kendall Jet assumed retired.

New Boston assumed retired upon in-service of NSTAR 345 kV Transmission Reliability Project - based on current Reliability Must Run agreement.

NSTAR 345 kV Transmission Reliability Project increase based on values used within RTEP04 assessments.

6.1.3. Operable Capacity Findings

6.1.3.1. New England

> At 90/10 peak load conditions, the New England summer operable capacity margin could become negative in the next two to four years. The need for resources will increase over time.

> Cold snap initiatives identified to date will add up to 2,000 MW during the winter and substantially improve reliability.

> Any unforeseen unit attrition would exacerbate the operable reserve margin picture.

> Transmission upgrades will allow for a window of opportunity to repower existing sites and/or add new resources.

> Increased demand response, possibly including use of temporary emergency generation, and conservation would be beneficial.

6.1.3.2. Southwestern Connecticut

> If Phase I of the Southwest Connecticut Reliability Project were delayed, the RFP for SWCT Emergency Capability resources would need to be maintained, and there could be no reduction of existing resources. There are limited generating unit sites in SWCT, and only small amounts of generation can be installed due to transmission limitations. Emergency generators, demand response, and energy conservation would be the only viable short-term actions for this area.

> Without the Southwest Connecticut Reliability Project Phase I & II, Southwestern Connecticut is at risk of having to shed load to maintain system reliability.

6.1.3.3. Connecticut

> If the Southern New England Reinforcement Project were delayed, approximately 536 MW (without emergency load swap) of additional resources would be required in the State of Connecticut by 2008. A delay of the Southwest Connecticut Reliability project would further increase the required resources by an additional 223 MW.

6.1.3.4. BOSTON

> The NSTAR 345 kV Transmission Reliability Project and the North Shore Upgrades would allow for the timely repowering of older inefficient units into cleaner, more efficient units — and/or the addition of new generating units — all preferably with dual fuel capability. A delay of these projects coupled with generator retirements could result in a shortfall of sufficient resources to ensure reliability.

> All six of the Kendall units have requested retirement/deactivation in the BOSTON Sub-area and three have been granted on an interim basis. A delay of the NSTAR 345 kV Transmission Reliability Project could necessitate their reactivation and/or trigger the need for new capacity by 2008.

> Any retirement or deactivation of the Salem Harbor Units could only be reliably achieved with the completion of the North Shore Upgrades. It would also depend on other unit retirements and the timing of the NSTAR 345 kV Transmission Reliability Project.

6.2. Loss of Load Expectation Analysis

ISO New England conducted a resource adequacy analysis by RTEP Sub-area for the period 2004-2013. It assessed the adequacy of generating resources and transmission facilities to meet forecasted Sub-area loads for a variety of scenarios based on planning assumptions, including known demand response programs.

LOLE Analysis determines if anticipated resources are sufficient to meet expected electrical demands. These assessments were conducted on both a New England-wide basis (assuming no transmission constraints in the system), and with a more detailed analysis that modeled transmission constraints between the RTEP Sub-areas. The results of these assessments are expressed as LOLE. The industry standard requires that the probability of disconnecting firm load due to inadequate resources will be no greater than 0.1 days per year LOLE, or one day in ten years. This is expressed as 0.1 LOLE.

The LOLE results are derived from probabilistic representations of both hourly demand and available resources. The intent of such modeling is to account for the dependence of system demand on variables such as weather conditions and the unpredictability of resource outages. The future performance of resources is based on the 1999-2003 historical unit equivalent forced and scheduled outage rates. This data reflects current maintenance and operating practices and unit maturity. For new units, special unit immaturity factors are developed based on recent performance of similar NEPOOL units.

The simulation tool calculates the system resource adequacy for thousands of scenarios and weighs the results based upon the likelihood of occurrence to determine the overall LOLE. For example, a program iteration with high load and a high unit unavailability may indicate a severe system problem, but that iteration would be weighted by its likelihood of occurrence with other iterations that may have a more favorable result.

Compliance with the New England LOLE criterion of 0.1 is a minimum threshold of system reliability because it does not capture operational issues, or detailed transmission limitations within and between the RTEP Sub-areas. Both factors could result in significant reliability problems for the region. It is necessary to fully recognize the interrelationship between LOLE and operational issues. To better reflect these concerns, ISO New England is undertaking a comprehensive review of the methodology to determine installed resource requirements (Objective Capability) and will involve stakeholders in this effort. It may also include review of industry standards and practices.

6.2.1. Findings

> From an LOLE perspective, the New England installed capacity requirements will increase by approximately 350 MW per year from approximately 29,000 MW[17], as currently required for the 2004/05 Power Year[18].

> Assuming that no existing units will retire or deactivate, New England will fail to meet the LOLE criterion in the 2012 timeframe. Retirement of key generators would advance the need for new resources. As previously discussed, this result does not account for operating issues summarized in the Operable Capacity Analysis, e.g., that New England could be short of necessary resources as early as 2006.

> The LOLE results show that relief of the import limits into the Southwest Connecticut, Connecticut and BOSTON Sub-areas is beneficial, especially with the possible deactivation of critical generators in those Sub-areas.

> RTEP04 has identified the need to enhance current methods used to calculate resource requirements (Objective Capability) to better reflect operational reliability considerations.

[17]This value is based on "The Review of NEPOOL ICAP Requirement for Power Year 2004/2005." This review can be found at www.iso-ne.com/historical_data/periodic_reports/objective_capability_review/.

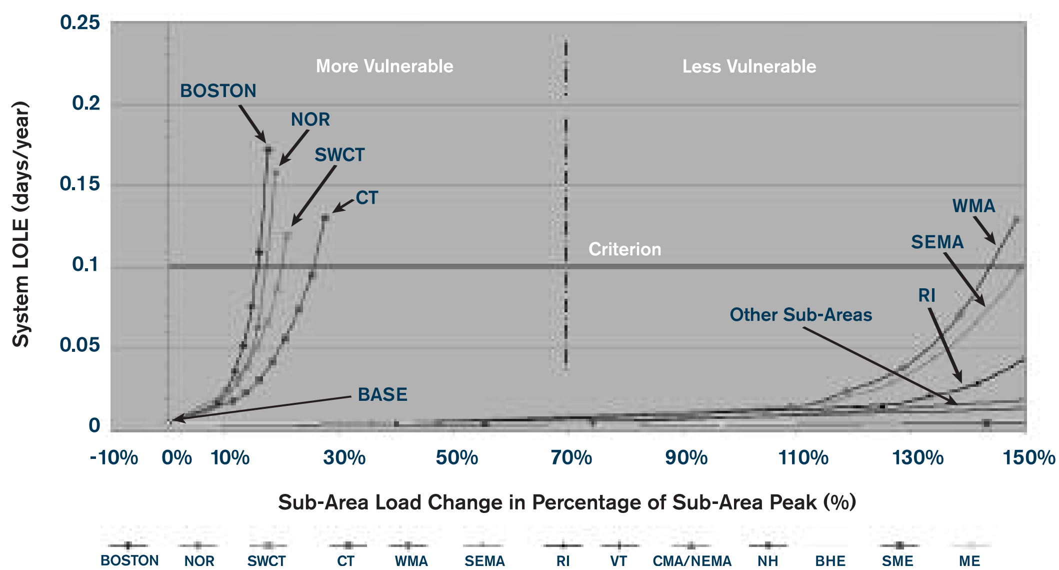
[18]A Power Year is from June 1 of a given year through May 31 of the following year.

6.3. Incremental Reliability Analysis

Simulations were conducted to identify the impact on NEPOOL system LOLE of changing RTEP Sub-area load/resources for the year 2005. Figure 6.6 illustrates the results of this simulation. This graph shows the impact of unit attrition, long-term unit outages, and higher than expected load growth on the NEPOOL system LOLE. The RTEP Sub-areas most sensitive to load/supply variations are BOSTON, NOR, SWCT, and CT.

FIGURE 6.6

System LOLE per Change in Percentage of RTEP Sub-area Load (%)



6.3.1. Findings

> The BOSTON, NOR, SWCT, and CT Sub-areas are extremely vulnerable to unexpected load increases, unit deactivations, or generator forced outages including fuel supply interruptions. Other Sub-areas are less vulnerable.

> Reductions in demand, additional generation, or demand response resources in those Sub-areas would provide the most effective LOLE benefits.

6.4. Need for Quick-Start Resources

Sub-areas often need quick-start capacity to meet system operation reliability requirements. In daily operations, quick-start resources are used to replenish the capacity and energy lost due to a sudden and unexpected loss of a generating unit or transmission facility. They also help to avoid the need to disconnect uninterruptible load under severe system conditions. New England complies with the NPCC and NERC operating performance reliability standards that require an adequate regulation of tie line flows and recovery from system contingencies within prescribed timeframes. Due to the lack of quick-start capability in transmission-constrained areas, "out-of-merit" generation is often committed on line to provide the needed system security. If additional quick-start capability were available in these transmission constrained load pockets, commitment of "out-of-merit" units for system reliability could be significantly reduced. The 2005 RTEP will investigate quick-start capacity requirements in the transmission constrained Sub-areas.

7.0 Economic Assessment and Incremental Costs

7.1. Economic Assessment Methodology

RTEP04 provides a range of market information that will assist market participants in evaluating various generation and demand-side options within the New England electricity market. It should be noted that there is a high degree of uncertainty associated with many of the assumptions. Future fuel prices, unit retirements, unit availability performance, bidding practices, load growth, and other assumptions all could affect congestion costs, and all are uncertain. However, even with these uncertainties, the modeling results are indicative of relative values and trends.

Several different cases were examined and are provided in the RTEP04 Technical Report. To evaluate the economic benefits of network upgrades, ISO New England calculates the relative change in production costs with and without the transmission upgrade — known as the Resource Cost Method. This method is in accordance with NEPOOL Planning Procedures.

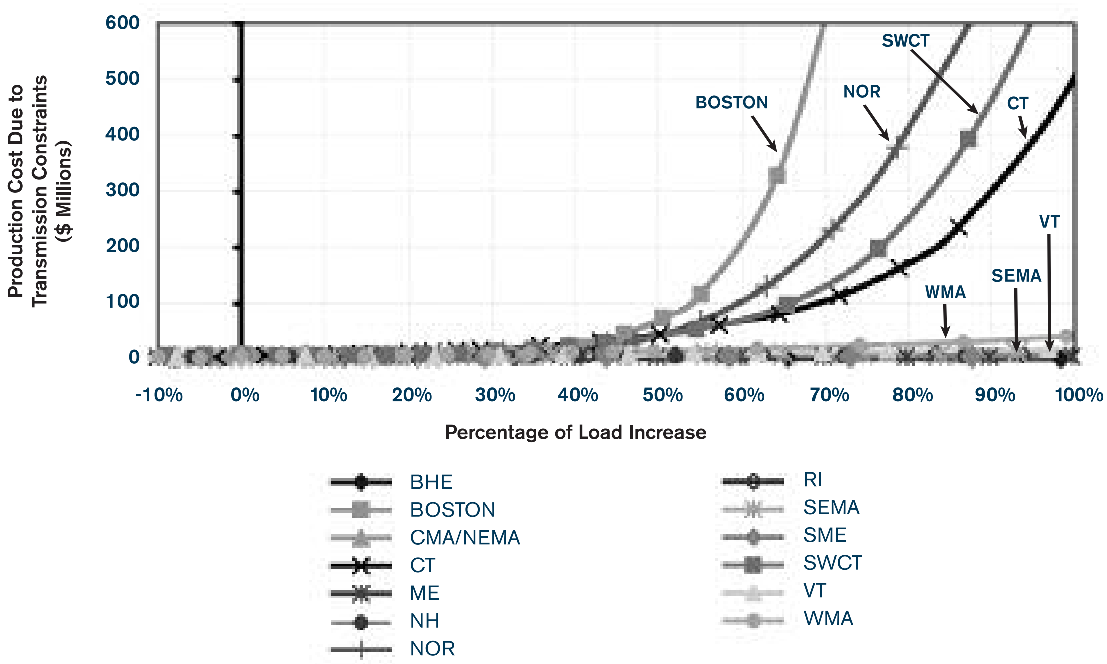
7.2. Incremental Economic Analysis

ISO New England conducted sensitivity studies to identify the RTEP Sub-areas having the greatest risk of creating higher resource costs due to transmission constraints, as measured by changes in resource costs system-wide. This is done by evaluating changes in load or reductions in generation in each of the Sub-areas to determine the overall system-wide impact.

Figure 7.1 illustrates this information on a Sub-area basis. As can be seen, BOSTON, NOR, SWCT and CT are more sensitive to these changes than the other Sub-areas. In addition, it should be noted that it takes very large increases in load or decreases in generation to produce significant changes in resource costs in any of the Sub-areas. Therefore, only two transmission projects in RTEP04 have been justified based on economic benefits alone. Both of these projects were justified based on reductions of losses.

FIGURE 7.1

Production Cost Changes versus Sub-area Load Increases (2005)



8.0 Fuel Diversity

8.1. Fuel Diversity Issues

Gas-fired and dual fuel units primarily fueled by natural gas represent approximately 37 percent of New England's installed generating capacity and about 30 percent of its annual energy. The problem with such a high level of dependence on natural gas was dramatically illustrated during the January 2004 Cold Snap. ISO New England continues to take steps necessary to reliably plan for and address winter availability issues surrounding gas-fired generating units. Following are actions that ISO New England has already taken or plans to take in the near future:

1) ISO New England has evaluated the outlook for supply and transportation of natural gas into and within New England on various occasions in the past. This information has provided regional stakeholders, reliability planners and regulatory agencies with important insights to help them respond effectively to the gas delivery challenges. The ISO New England report prepared by Levitan & Associates, Inc, *Steady-State and Transient Analysis of New England's Interstate Pipeline Delivery Capability, 2001-2005*, dated January 2002, documents the impact on gas deliveries to New England's electric generation sector with respect to the coincidental winter demand on traditional gas utilities. Impacts resulting from postulated gas-side contingencies were also evaluated. Key findings identified "generation-at-risk," subsequent upstream and downstream effects, and response times required to replace lost generation.

2) In July 2003, ISO New England published a White Paper on regional fuel diversity issues entitled *Natural Gas and Fuel Diversity Concerns in New England and the Boston Metropolitan Electric Load Pocket.* To address issues identified within the White Paper, ISO New England established the Fuel Diversity Working Group, which reports to the TEAC. In the first quarter of 2004, the Fuel Diversity Working Group was charged with the Electric & Gas Wholesale Initiative Project to address operational, market, and communications problems experienced during the January 2004 Cold Snap. To date, the Fuel Diversity Working Group-Electric & Gas Wholesale Initiative has held two workshops, allowing regional stakeholders to identify cold snap issues and propose solutions. The Fuel Diversity Working Group-Electric & Gas Wholesale Initiative maintains an Issue List and has segmented the remaining open issues into the categories of reliability, markets, and communications. The Fuel Diversity Working Group-Electric & Gas Wholesale Initiative is actively pursuing development and implementation of several solution sets prior to the upcoming winter of 2004/2005.

3) As a result of the January 2004 Cold Snap, ISO New England has actively encouraged stakeholder input to assist in problem resolution. NEPOOL has responded by creating the Cold Snap Task Force. The Cold Snap Task Force is providing stakeholder assistance to the ISO New England initiatives and the Fuel Diversity Working Group-Electric & Gas Wholesale Initiative project. Straw proposals have been submitted to advance the timelines of the wholesale electric market and thus provide increased coordination with the region's natural gas market. ISO New England, with input and feedback from the NEPOOL Cold Snap Task Force, is actively pursuing development and implementation of market-based solutions prior to the upcoming winter of 2004/2005.

4) In 2003, ISO New England became a member on the NERC Gas/Electric Interdependency Task Force and has actively participated in the development of several draft recommendations, including:

> A regional assessment program to review the impact of any interruption in the fuel transportation infrastructure that could impact electric system reliability.

> Improved gas and electric outage coordination.

> New fuel diversity reliability standards.

> Analysis of electric/gas infrastructure performance under contingencies.

These are currently under consideration by the NERC Board of Directors. ISO New England supports the initiatives being taken at the national level by NERC and has already implemented most of the NERC Gas/Electric Interdependency Task Force's recommendations.

5) ISO New England and representatives from the natural gas industry have formed a new Electric/Gas Operations Committee (EGOC). Its objective is to promote greater regional reliability for both industries through improved education, understanding, communications and coordination. The Electric/Gas Operations Committee (EGOC) is envisioned to be responsible for:

> Cross-training of electric and gas system operators.

> Establishing emergency communications protocols and procedures.

> Assessing and addressing system restoration issues.

> Assessing coordination of electric and gas system maintenance requirements.

> Addressing other common issues.

In summary, ISO New England will:

> Implement short-term fixes to address cold snap issues.

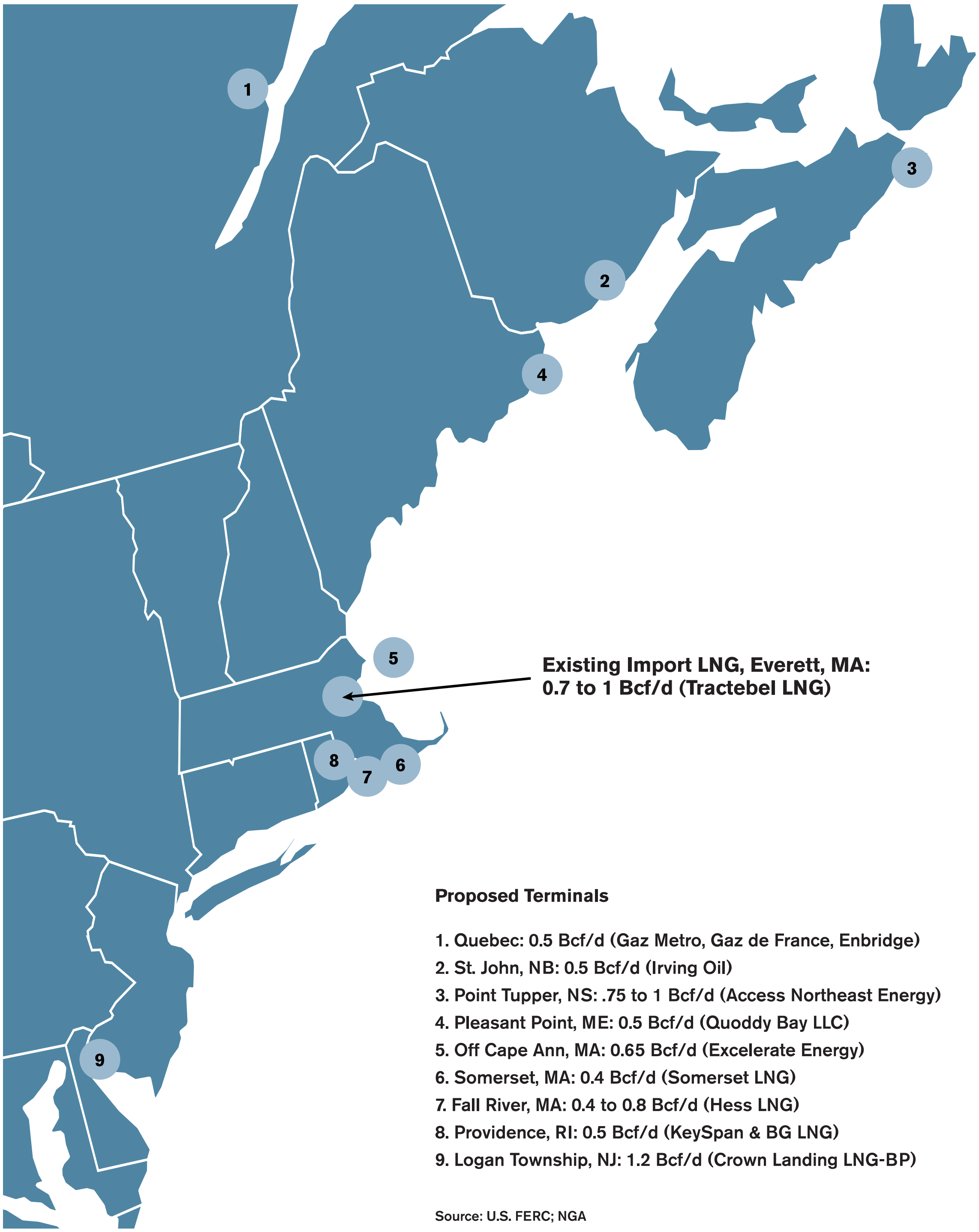
> Develop longer-term solutions that address "firm fuel" issues through the resource adequacy discussions within the region.

8.2. Status of Liquefied Natural Gas Supply to the Northeast

Over the next several years, new gas infrastructure investments are planned to meet the increase in demand for natural gas in New England and the Northeast. These include additions to pipeline deliverability and liquefied natural gas import capability. Figure 8.1 shows existing and proposed liquefied natural gas import terminals. Based on ISO New England analysis, it is critical that additional liquefied natural gas import terminals be constructed in the Northeast to provide reliability.

FIGURE 8.1

Existing & Proposed Liquefied Natural Gas Import Terminals



Proposed Terminals

1. Quebec: 0.5 Bcf/d (Gaz Metro, Gaz de France, Enbridge)
2. St. John, NB: 0.5 Bcf/d (Irving Oil)
3. Point Tupper, NS: .75 to 1 Bcf/d (Access Northeast Energy)
4. Pleasant Point, ME: 0.5 Bcf/d (Quoddy Bay LLC)
5. Off Cape Ann, MA: 0.65 Bcf/d (Excelerate Energy)
6. Somerset, MA: 0.4 Bcf/d (Somerset LNG)
7. Fall River, MA: 0.4 to 0.8 Bcf/d (Hess LNG)
8. Providence, RI: 0.5 Bcf/d (KeySpan & BG LNG)
9. Logan Township, NJ: 1.2 Bcf/d (Crown Landing LNG-BP)

Source: U.S. FERC; NGA

9.0 Air Emissions

This section reports on the analyses conducted to ascertain expected trends in fossil power plant air emissions during the ten-year study period, 2004-2013. The base-case analysis examines the air emissions based on known air permit changes and generator output as predicted by the Inter-Regional Electric Market Model (IREMM). Sensitivity cases were conducted to determine if differing fuel costs and specific transmission upgrades would impact New England-wide emissions. The analyses do not account for emissions from generating units located outside of New England, which may be exporting or importing electricity to or from New England.

Figure 9.1 through Figure 9.3 show aggregate annual emissions over the study period for SO_2, NO_X and CO_2. The charts show emissions for both constant emission rates and emission rates assumed as compliant with changing air permit regulations. Significant impacts are highlighted on each chart. They show that SO_2, NO_X and CO_2 emissions are greater when gas prices increase because oil-fired generation, which has higher emissions, replaces some of the gas-fired generation. Full details, including case designations and trend charts, may be found in the RTEP04 Technical Report.

FIGURE 9.1

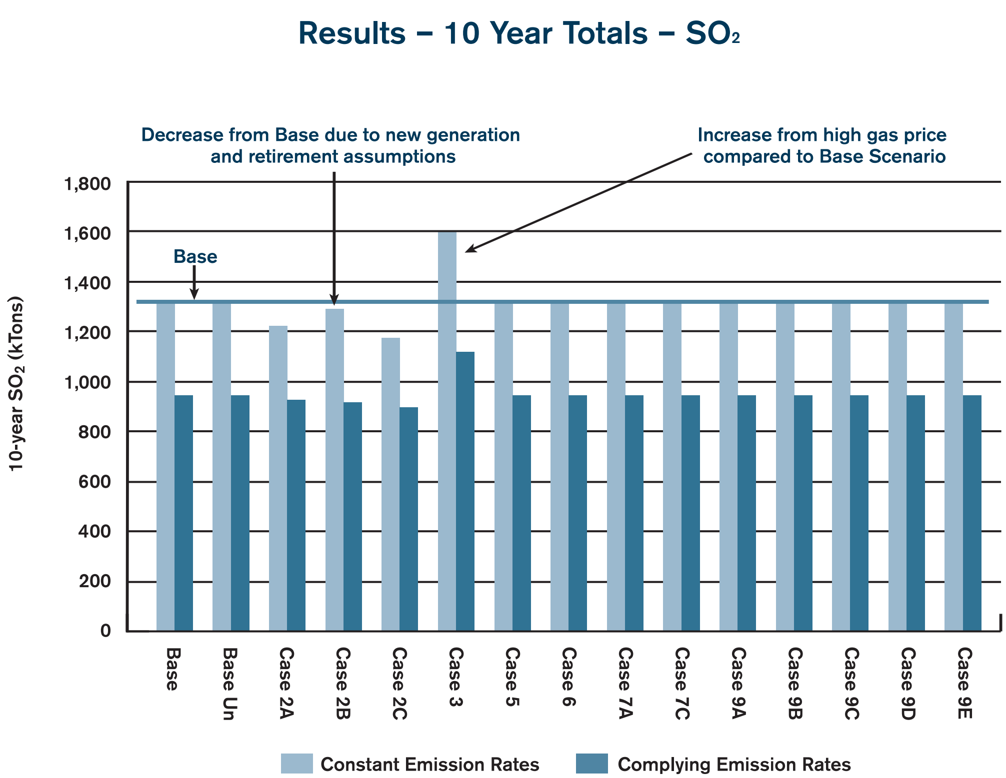


FIGURE 9.2

Results – 10 Year Totals – NO_x

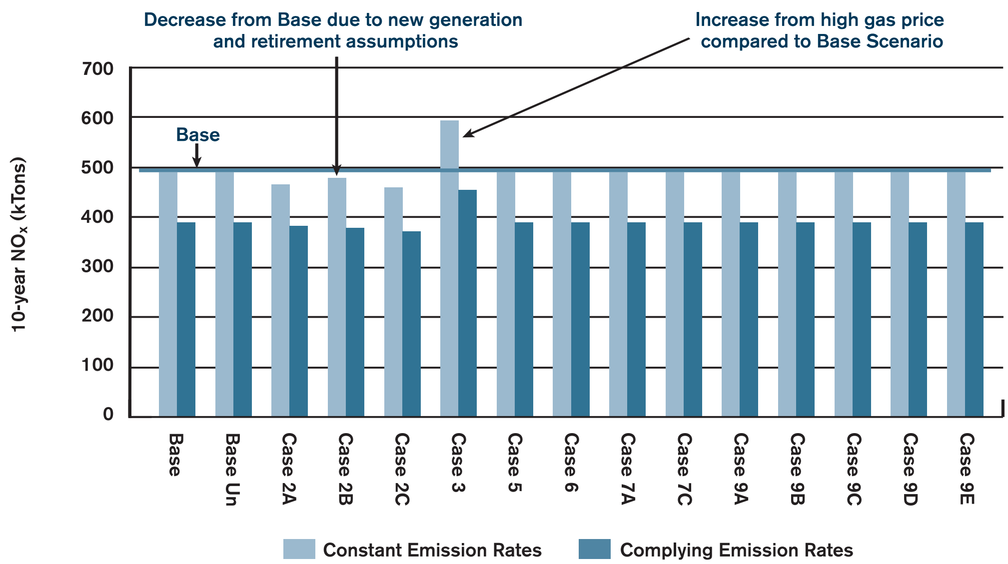
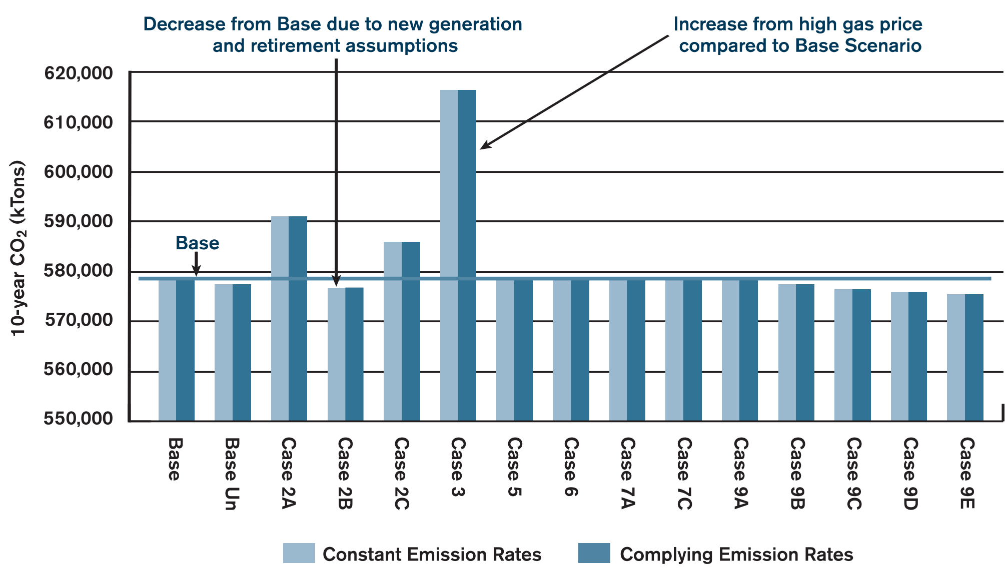


FIGURE 9.3

Results – 10 Year Totals – CO_2



9.1. Findings

- Due to stricter air regulations, fossil unit air emission trends are downward in the near term, and then show gradual increases with load growth.

- The 345 kV upgrade projects do not significantly change the New England annual emissions of SO_2, NO_x or CO_2 over the next ten years.

- The high price of natural gas showed the most impact on air emissions of the cases examined.

10.0 Historical Market Data and Observations

This section summarizes certain market data from the first full year's experience under SMD in New England. Where appropriate, information is presented in the context of the RTEP Sub-areas; the data presented are for the Real-Time market. These include LMPs, interface flows, Operating Reserve Credit payments (or "uplift"), and Reliability Agreement costs.

For a more complete discussion of LMP, Operating Reserve Credit, and Reliability Agreement, see the 2003 Annual Markets Report at http://www.isone.com/smd/market_analysis_and_reports/public_forum_and_annual_report/2004_Annual_Forum/.

10.1. Locational Marginal Prices

LMP is one of the key features of SMD. LMP provides price signals for market transactions and economic signals indicating where investment in the bulk electric power system is needed — including the location of new generating units, expansion of transmission facilities, and participation in demand response programs. These elements are required in a well-functioning market to alleviate constraints, increase competition, and improve the system's ability to meet power demand.

Real-Time market LMPs and components in RTEP Sub-areas for the March 2003 to February 2004 period are shown in Figure 10.1 and Figure 10.2. The three Maine Sub-areas have the lowest LMPs due to lack of congestion and negative marginal loss components. The three Connecticut Sub-areas have the highest LMPs due to frequent congestion and positive loss components.

For most of the RTEP Sub-areas, congestion, as measured by the congestion component of LMP, has been minimal. The three Sub-areas in the Connecticut load zone have positive congestion prices (SWCT and NOR are the highest) over the period, while the three Sub-areas in the Maine load zone have negative congestion prices.

The marginal loss component of LMP exhibits a pattern similar to the congestion component of LMP: positive marginal loss prices for the three Connecticut Sub-areas, as well as VT, CMA/NEMA, and WMA, and negative marginal loss components for the three Maine Sub-areas.

FIGURE 10.1

Load Weighted Average Locational Marginal Price RTEP Sub-areas, March 2003 to February 2004

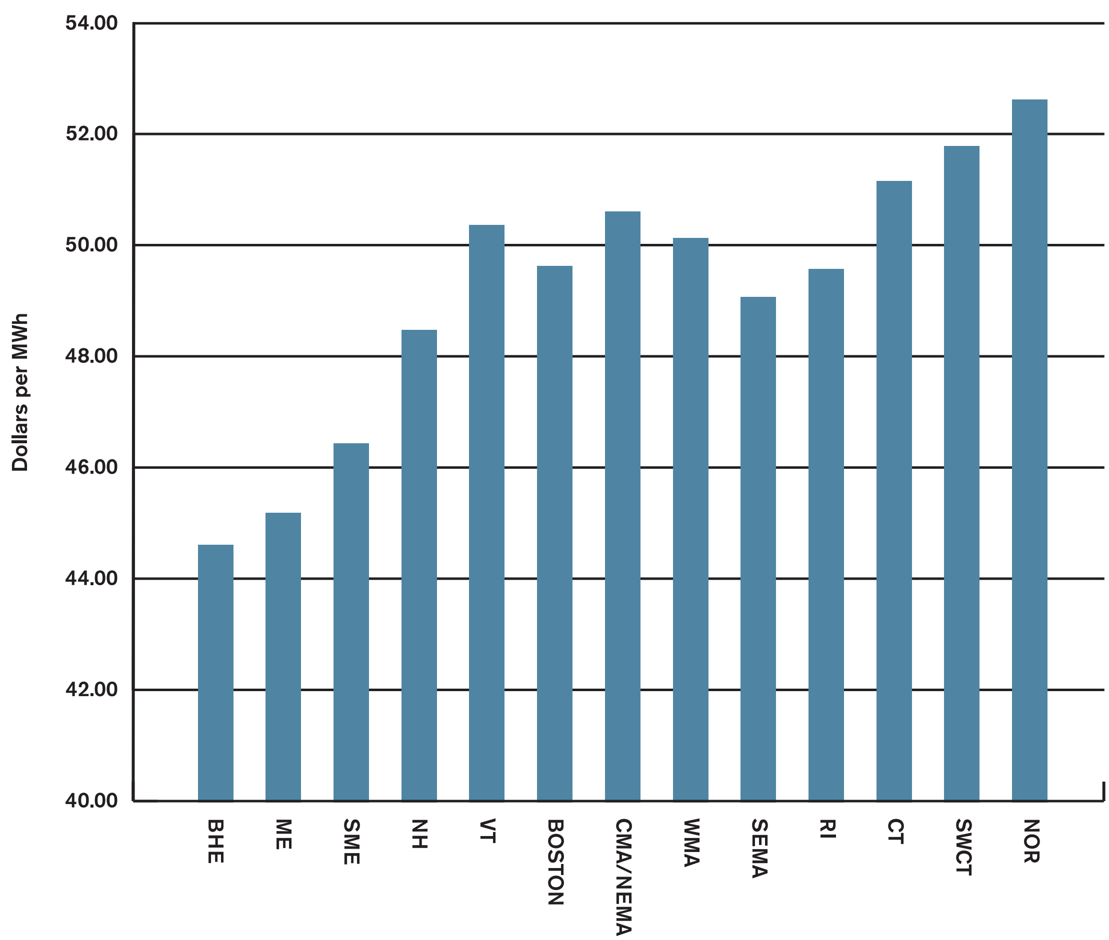


FIGURE 10.2

Average Congestion and Marginal Loss Component of LMP RTEP Sub-areas, March 2003 to February 2004

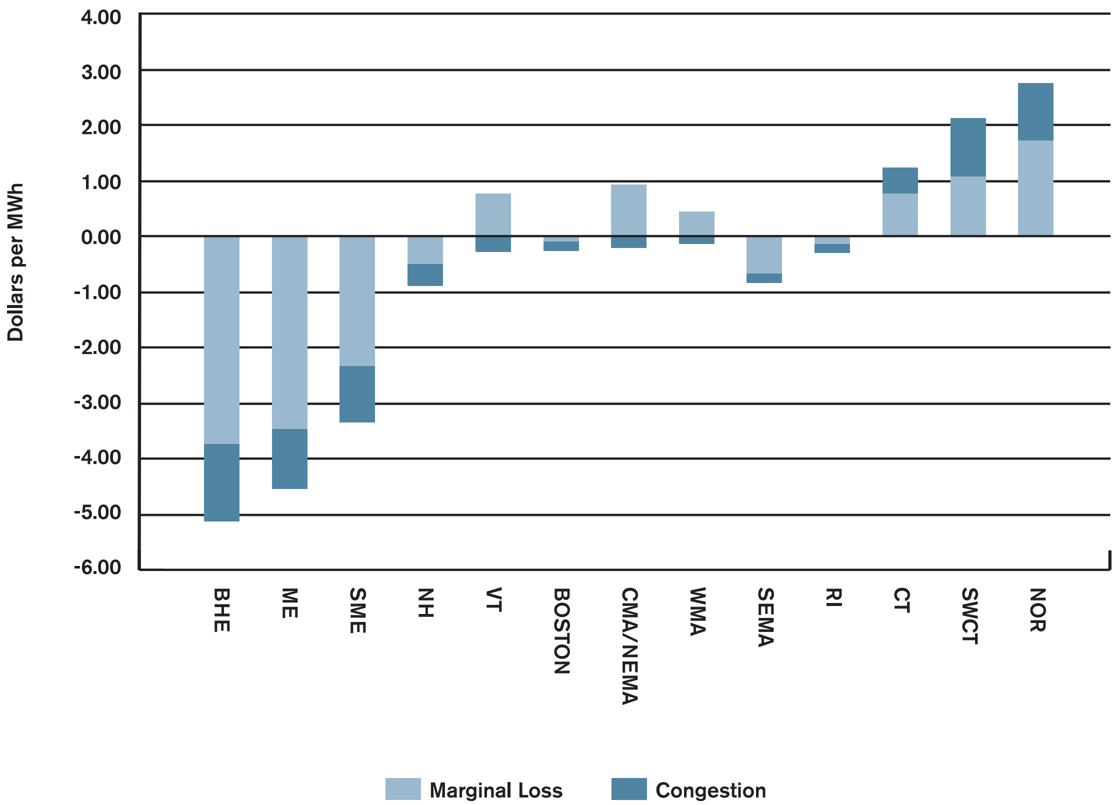
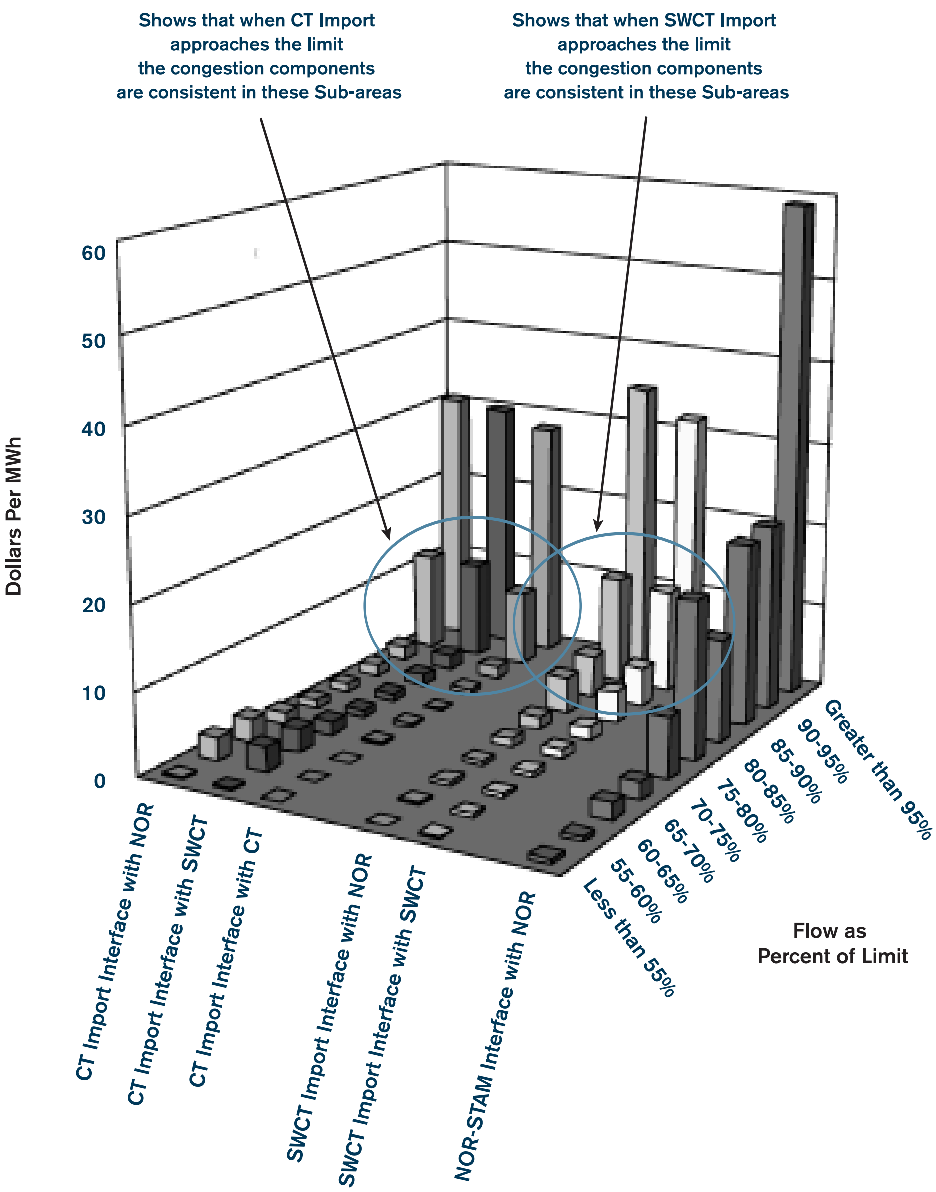


Figure 10.3 shows the average congestion component of LMP by Sub-area for the period March 2003 through February 2004 as it relates to flow over interfaces expressed as a percentage of the interface limit. As can be seen from the figure, there is a positive correlation between the loading of the interfaces and the congestion component of LMP for the three Connecticut Sub-areas. As the flow of energy over an interface approaches the interface limit, the congestion component of LMP increases for all Sub-areas associated with that interface.

FIGURE 10.3

RTEP Sub-area Average Congestion Component of LMP from March 2003 to February 2004 by Overflow Interface as Percent of Interface Limit



10.2. Operating Reserve Credit Payments

Although Operating Reserve Credit can and does occur in the Day-Ahead market, this report presents Operating Reserve Credit for the Real-Time market only. During the period March through December 2003, over three-quarters of the Operating Reserve Credit came from the Real-Time market.

There are four types of Operating Reserve Credit: (1) Economic Operating Reserve Credit[19] paid to eligible units that provide operating reserves and are not flagged for another type of Operating Reserve Credit; (2) Reliability Must Run Operating Reserve Credit paid to units that are required for reliability within a particular region on that particular day; (3) Voltage Amperes Reactive (VAR) paid to units providing VAR support to the transmission system[20]; and (4) Special Constraint Resources Operating Reserve Credit paid to units that provide Special Constraint Resources Service for local reliability under Schedule 19 of the NEPOOL Tariff.

From March 2003 to February 2004, real-time Operating Reserve Credit (composed of Economic, VAR, daily Reliability Must Run, and Special Constraint Resources) totaled approximately $94 million. All VAR Operating Reserve Credit payments ($0.9 million) were made to generation that was required to control voltage levels during low load periods in the Boston area. Units in the Connecticut SMD load zone were paid the largest amount of daily Reliability Must Run Operating Reserve Credit ($35.4 million), followed by payments to units in the SMD NEMA/Boston region ($8.1 million). Table 10.1 presents the total Operating Reserve Credit payments by category.

TABLE 10.1

Total Operating Reserve Credit Payments March 2003 to February 2004

Operating Reserve Credit Type	RT Market (Millions of Dollars)
Economic	$40.8
Reliability Must Run	$43.5
Special Constraint Resources	$8.5
VAR	$0.9
Total	$93.7

[19]Economic Operating Reserve Credit payments are made to generating units committed by ISO New England for regional needs.

[20]VAR support from generators is required to regulate system voltage within reliability criteria. Units that provide VAR support may incur a shortfall between their total daily supply offers and market revenues because, in providing the service, they may be dispatched out of merit order. Operating Reserve Credit costs for VAR service are billed to market participants through the Regional Transmission Tariff.

10.3. Reliability Agreement Costs

FERC has ordered that Reliability Agreements should terminate immediately upon the implementation of a locational capacity mechanism or a regional deliverability requirement. FERC has accepted Reliability Agreements but remains committed to the implementation of a market-based mechanism to appropriately compensate generators providing reliability services. The agreements are intended to ensure that generators needed for reliability are adequately recovering revenues until a permanent market-based solution is in place. The generation covered by these contracts will be part of the functioning locational capacity market that will develop in New England. The net cost of the Reliability Agreements represents significant annual costs to Boston ($23.8 million) and Connecticut ($56.6 million).

10.4. Observations

> The three Connecticut RTEP Sub-areas have the highest LMPs due to the most frequent congestion and positive loss component.

> The Connecticut SMD load zone paid the largest Operating Reserve Credit, followed by NEMA/Boston.

> The Connecticut SMD load zone paid the largest amount of Reliability Agreement costs, followed by Boston.

11.0 Distributed and Renewable Resources

Distributed resources are playing a greater role in the New England market. They include ISO New England's Demand Response Program, energy efficiency, and distributed generation. Renewable resources[21] are required by State Renewable Portfolio Standards.

ISO New England's Demand Response Program enrolled resources encompass three programs: Real-Time Demand Response, Real-Time Price Response, and Real-Time Profiled Response. A Day-Ahead Demand Response program is being developed for implementation in 2005, and improvements have been made in the demand response program administration and marketing. The demand response programs were called on August 15, 2003, the day after the Blackout, and had an overall response rate of 57 percent. An RFP for SWCT Emergency Capability was issued in December 2003 and resulted in selection of 125 MW of distributed resources for the summer of 2004, increasing up to 256 MW by the summer of 2007.

Increasing use of distributed resources can play an important role in fostering both system reliability and market efficiency. This may be achieved through use of distributed generation. Use of existing emergency generators at customer locations is possible, but these are mostly diesel engines and limited by state air emission restrictions. Cleaner forms of distributed generation, such as micro turbines and fuel cells, are more attractive, but also more expensive. As a result, they have not significantly penetrated the market.

State requirements for Renewable Portfolio Standards are drivers for increased renewables, including fuel cells. Connecticut, Massachusetts, Rhode Island, and Maine have standards in place. Vermont is also developing a similar Renewable Portfolio Standards program. The Connecticut, Massachusetts, and Rhode Island regulations require growth in Renewable Portfolio Standards resources such that, by 2010, an additional 5.5 million MWh of energy must be from new renewables. Consequently, there is an immediate need for additional renewable projects just to meet the new Renewable Portfolio Standards requirements in those states. ISO New England has close to 900 MW of proposed wind projects in its transmission interconnection study queue, none of which has started construction. If and when they are built, these projects might provide about half of this required energy.

[21]Renewable resources are energy sources that are replenishable by natural forces. They typically include solar energy, wind power, ocean thermal, tidal power, and biomass fuels. States have slightly different definitions for Renewable Portfolio Standards purposes.

12.0 Inter-Regional Planning

Planning activities must be coordinated on an inter-regional basis to ensure the long-term reliability of the system. In addition, the elimination of planning "seams" across Control Area borders would improve the overall economic performance of the regional system and facilitate the interconnection of new resources near the border. ISO New England has ensured the coordination of studies through the following actions:

> All major RTEP04 upgrades and system assessments have been reviewed for inter-area impact through active participation in NPCC committees, task forces, and coordinated planning (CP) working groups. For example, a study by Working Group CP-10 recently showed that relief of New England's East-West Interface would likely increase the ability to transfer power on an inter-area basis. The study suggests this as an additional benefit of the Southern New England Reinforcement Project. NPCC activities have also significantly improved the quality and consistency of system models necessary for studies, including the development of common databases.

> Neighboring Control Areas have been kept advised of RTEP developments through the TEAC and through close informal communication on project developments that could impact neighboring systems. A major project in any of the Control Areas of NPCC is reviewed by NPCC to assure it will not have an adverse impact on the other Areas. Projects are further examined through the MAAC-ECAR-NPCC Study Committee[22], to assure there are no adverse inter-regional effects.

> An inter-ISO working group exchanges information on system plans, which results in better coordination of studies and planning issues. This effort includes a monthly exchange of the queue of system impact studies of projects that could potentially impact neighboring systems. Coordinating the scope of work and identifying needed improvements is consistent with FERC and regulatory policy.

> ISO New England, the New York ISO, and PJM Interconnection have recently signed a protocol with limited participation by the Independent Electricity Market Operator (IMO), Hydro-Québec TransÉnergie, and New Brunswick. It establishes a Joint ISO/RTO Planning Committee (JIPC) to formalize data and information exchange, including the coordination of

[22]MAAC stands for the Mid-Atlantic Area Council and ECAR stands for the East Central Area Reliability Council.

Tariff studies. Significantly, it calls for publication of a Northeastern Coordinated System Plan with input from an Inter-area Planning Stakeholder Advisory Committee, an open group that will be similar to the TEAC. This process is scheduled to begin during the fall of 2004 followed by a joint statement summarizing the system plans. The issuance of a joint Northeast Inter-area System Plan is expected in 2005.

13.0 Stakeholder Comments

ISO New England has sought input from the TEAC on improving the overall RTEP process. The TEAC participants have provided very valuable contributions. ISO New England encourages any interested entity, including state and local officials, to be active participants in the development of future RTEP reports.

14.0 Transmission Planning Studies and Projects

This section discusses various aspects of the ongoing transmission studies, updates the status of major transmission projects, and provides some details and summaries of the transmission project listing.

14.1. Transmission Studies

Transmission Planning is an important component of the RTEP04 effort. Various studies have been performed or are in progress to assure that the New England interconnected bulk electric power supply system is designed with sufficient transmission capacity to reliably and efficiently integrate resources and serve area demand. Transmission system analyses assure compliance with NEPOOL and NPCC reliability standards and address observed and potential transmission congestion issues.

The studies address a wide range of system concerns, identified by both ISO New England and transmission providers. Additional conditions have been identified through actual system operations or have been recognized in other studies.

The New England transmission system is subject to a number of different performance issues — each must be addressed to provide for system reliability. Studies examine such issues as thermal loading, minimum voltage, voltage regulation, transient stability, dynamic oscillations, harmonics, transients, over voltages and short circuit interrupting capability. Acceptable system performance can be achieved through improvements. These may range from major transmission infrastructure additions to high technology solutions, such as flexible AC transmission systems and the application of dynamic ratings. Projects proposed as an outcome of the studies may be altered in scope or timing, or even eliminated, as market responses provide alternate solutions to the problems.

Approximately 40 studies are currently in progress. Complete descriptions of on-going and recently completed Transmission Planning Studies can be found in the RTEP04 Technical Report.

14.2. Status of Major Transmission Projects

This section gives a brief status of proposed or planned transmission projects that include 345 kV facilities which cost over $35 million.

14.2.1. Northeast Reliability Interconnect Project

The Northeast Reliability Interconnect Project, also known as the Second New Brunswick tie project, is proceeding. It is comprised of a new 345 kV transmission line connecting LePreau substation in New Brunswick to Orrington substation in Northern Maine, and includes supporting equipment. Review and approval pursuant to Sections 18.4 of the NEPOOL Agreement occurred in early 2003. Recent efforts have focused on comprehensive enumeration of the reliability and economic needs and benefits of this project.

This project is one of several alternatives that will address ongoing reliability concerns between New England and New Brunswick. These include inadvertent tripping of the Keswick-Orrington 345 kV tie and inadvertent operation of the Keswick GCX Special Protection System. There are additional reliability benefits associated with this project, including mitigation of overloads resulting from the Maine Yankee 377/375 double circuit tower outage, improvement in Central Maine Power Company transient voltage response, mitigation of Northeast Maine (BHE) contingency exposure, enhancement of the ability to perform maintenance/reconstruction on the Keswick-Orrington 345 kV line, improvement in opportunities for capacity diversity exchange with New Brunswick, and improvement in access to capacity and energy for Maine Public Service and Eastern Maine Electric Cooperative.

There are also a number of economic benefits associated with this project. Based on recent history, the addition will result in savings in transmission losses on the New England bulk electric power system that would otherwise average $4 million per year. Increased access to relatively lower cost generation in New Brunswick is projected to reduce production costs in New England by approximately $31 million over a six-year period. These two factors should provide approximately $9 million in annual savings from a production cost perspective in addition to the reliability benefits.

Current plans are for completion of construction by 2007 at a cost of $90.4 million.

14.2.2. Northern New England Transmission Transfer Capability Enhancement

Over the past three years, various studies have explored short- and mid-term options to increase Northern New England transmission transfer capability. These enhancements address such needs as sub-regional load service, system operability, and regional capacity and energy adequacy. Short-term upgrades that have been implemented include installation of static capacitors and line terminal and substation modifications in Southern New Hampshire. Studies focusing on reliability enhancements in both central and Southern-coastal New Hampshire may identify system modifications that will indirectly benefit transfer capabilities. For example, the Y138 Closing Project, intended to address Central New Hampshire reliability, will most likely increase ME-NH interface capability by approximately 100 MW and will also increase the margin on the Surowiec-South interface. Ongoing studies have demonstrated the need for additional 345/115 kV transformations in Southern New Hampshire at a location such as Deerfield. These and other projects needed to meet the Northern New England reliability requirements will necessitate additional assessments of transfer capability for transmission interfaces in Maine and New Hampshire.

The following projects will have the most significant impact on voltage, stability, and thermal capability limits: elimination of the Buxton stuck circuit breaker situation; installation of a 500 MVAR static VAR compensator at Deerfield; and looping Buxton-Scobie 345 kV Section 391. All are needed to address conditional dependencies that do not meet current guidelines for reliable and operable designs. These projects have not yet been implemented.

Once the transfer capability improvements associated with the New Hampshire reliability projects have been determined, additional efforts will focus on the extent to which upgrades identified in previous studies can further improve transfer capabilities. The options will be considered both individually and in combination. A revised implementation schedule will likely be based on the resource adequacy needs of Southern and Western New England.

14.2.3. Northwest Vermont Reliability Project

The Northwest Vermont Reliability Project was originally reported on and approved in RTEP02. It includes a new 345 kV line, a new 115 kV line, additional phase angle regulating transformers (PARs), two dynamic voltage control devices, and static compensation. It is currently in the state hearing process, with a decision expected in early 2005. Review of this $156 million project pursuant to Sections 18.4 and 15.5 of the NEPOOL Agreement has been completed. Two separate applications ("Section 248") were filed with the Vermont Public Service Board, the first on May 23, 2003 for the Sandbar PAR, and a second on June 5, 2003 for the balance of the project. This was done to expedite consideration of the Sandbar work in light of the unexpected failure of the PAR at Plattsburgh, NY, which the Sandbar PAR is meant to replace. Construction was completed on the Sandbar unit in 2004, with the remainder of the projects to be placed in service in the 2005 to 2007 time frame.

14.2.4. Monadnock Upgrades

The Monadnock upgrades are meant to comprehensively address the reliability needs of a three-state area consisting of Southeastern Vermont, Southwestern New Hampshire, and North-central Massachusetts. These upgrades feature the addition of a Fitzwilliam 345 kV station, a 345/115 kV transformation, and the re-conductoring of a number of 115 kV lines. Additional studies are ongoing to determine whether dynamic, rather than static, voltage control is required. Most of these upgrades are needed by 2006 and are estimated to cost $76.8 million. This cost assumes dynamic voltage control is included in the upgrades.

14.2.5. NSTAR 345 kV Transmission Reliability Project

ISO New England reliability studies show the critical need to improve the reliability of the bulk electric power system in the BOSTON area by 2006. The construction of a Stoughton 345 kV station and the installation of three new 345 kV lines were found to be the most cost-effective option. The first stage, planned for service in 2006, will include construction of the Stoughton station, one 345 kV underground cable to Hyde Park, and one 345 kV underground cable to K Street. The second stage calls for another 345 kV underground cable to K Street to be installed by 2007.

The current estimated capital cost of this project is $217 million and will reduce the need to shed up to 400 MW of load for line outage contingencies.

14.2.6. North Shore Upgrades

Studies performed since RTEP03 have confirmed the preferred solution for the North Shore section of Boston. The project consists of expansion of the 345 kV station at Ward Hill to include additional 345/115 kV autotransformers and a new Wakefield Junction 345 kV station with associated 345/115 kV autotransformer. Total estimated cost is $50 million. Studies to secure approval pursuant to Section 18.4 of the NEPOOL Agreement are continuing. Procurement of long lead time equipment and initial siting investigations have begun. The Ward Hill portion of the project is scheduled for completion in 2006, followed by the Wakefield Junction piece in 2008.

14.2.7. Central Massachusetts Transmission Upgrades

The Central Massachusetts upgrades are a set of reinforcements to address the reliability needs of an area of Massachusetts bounded on the east by the Greater Metro west area, on the west by the western suburbs of Worcester, on the north by New Hampshire, and on the south by Rhode Island. These upgrades feature the addition of a Wachusett 345 kV station, 345/115 kV transformers, the re-conductoring of a number of 115 kV lines, and additional 69 kV-related modifications. Estimated to cost $36.2 million, the upgrades will be placed in service between 2005 and 2006. ISO New England has approved the project pursuant to Section 18.4 of the Restated NEPOOL Agreement.

14.2.8. Southern New England Reinforcement Project

Previous analyses have examined the capability of the Southern New England 345 kV system to convey power from resources on the 345 kV network to major load centers. 345 kV reinforcements appear to be the most practical alternative to improve the capabilities of this portion of the system. Considerable work has been done to identify a preferred alternative to address CT import needs. Analyses continue to support a 345 kV path either from Card to Lake Road to Sherman or W. Farnum to Millbury. Additional analyses are being performed to identify which refinements best facilitate utilization of the generation connected to the 345 kV network while best serving Rhode Island's access to it. This 76-mile project, estimated to cost $125 million, is planned to be in service by 2008 and will provide 800 MW to 1,000 MW of improved transfer capability.

14.2.9. Southwest Connecticut Reliability Project

ISO New England has been conducting studies of the Southwest Connecticut region for three years. As reported in RTEP02, the Southwest Connecticut Reliability Project would include a number of system reinforcements and an overhead 345 kV loop connecting existing 345 kV facilities in Middletown and Bethel. RTEP03 reconfirmed the need for the project in its entirety; however, it pointed out that some modifications would probably be necessary due to local requirements. Ongoing studies have focused on alternative routings, alternative technologies, and significant technical performance issues raised by replacing sections of overhead line with underground cable.

In July 2003, the Connecticut Siting Council approved a combination overhead/underground alternative for the 20-mile Phase I Project from Bethel to Norwalk. This modification required supplemental studies to determine any additional system modifications required to develop a cost-effective, acceptable design that could proceed through Section 18.4 of the NEPOOL Agreement. A number of modifications were found to be necessary, and with them, the recommendation for 18.4 approval and subsequent ISO New England approval was issued in February 2004.

Regulatory filing of Phase II, the Middletown to Norwalk section (proposed to include approximately 24 miles of underground cable), was made in the Fall of 2003, and the Connecticut Siting Council hearings are now in progress. The extension of low impedance, high capacitance cable into a relatively weak corner of the New England grid has created, heretofore, unanticipated risks to the bulk electric power system. Heavy flow and thermal overload problems can be mitigated by the use of four strategically placed series reactors; however, the possibility of harmonic resonance conditions has intensified the analytical process.

The current cost estimate for Phase I is $200 million. The Phase II cost estimate remains at $690 million, realizing that the siting process and additional analyses may have a significant impact on this figure. Other studies are being conducted to assess transmission reliability needs in the region.

14.3. Transmission Projects

The complete NEPOOL Transmission System Project Listing, found in Appendix Section 16, identifies appropriate transmission solutions to Pool Transmission Facility system needs. All the projects that appear in the July 2004 NEPOOL Transmission System Project Listing are sorted by the following classifications:

Part 1: Projects Needed for Reliability

Part 2: Projects Needed for Interconnection

Part 3: Projects Promoted for Economic Benefit

Part 4: Elective or Other Projects

Part 5: Local Projects (non-Pool Transmission Facility)

Parts 1 and 3 require that ISO New England's Board of Directors approve the need for the project, and it must be shown that Part 4 is well coordinated with all other planned facilities. Similarly, local projects with potential impacts on Pool Transmission Facility are included in the NEPOOL Transmission System Project Listing, recognizing that there may be some minimal Pool Transmission Facility-related transmission costs. As with other projects, Part 2, interconnection projects, achieve final design approvals through the 18.4 process.

In the complete NEPOOL Transmission System Project Listing, Section "a" of each of the above classifications includes those projects that have completed the review process, and section "b" includes those projects that have not yet completed review.

Table 14.1 highlights the majority of the projects discussed in some detail in RTEP04. It includes: a reference to the RTEP04 Technical Report Section that discusses the related study, as well as estimated costs; status of NEPOOL approval; and expected in-service date. Projects costing $10 million or more are shown in the list. Together they represent 94 percent of the estimated cost for all active projects.

The estimated costs for projects with 15.5 approval are engineering grade estimates. Estimates for projects without 15.5 approval are "order of magnitude" estimates only. Planned projects have considerable supporting analysis, while proposed projects require additional study. Conceptual projects are in the early stages of development.

The 2004 NEPOOL Transmission System Project Plan now totals $2,140 Million, an increase of $209 Million above the RTEP03 Plan estimate. This is attributable to the following:

> Updated Engineering Analyses and Costs for Monadnock Area Reliability Project:	$45 Million
> Updated Engineering Analyses and Costs for NSTAR 345 kV Transmission Reliability Project:	$47 Million
> Northeast Reliability Interconnection Project – New Costs totaling:	$90 Million
> Revised estimates:	$15 Million
> "TBD" costs now with estimates:	$2 Million
> New RTEP04 Projects:	$10 Million

Cost estimates included in Table 14.1 are approximate for the following reasons:

- Projects will be added and deleted, possibly due to preemption by market responses.
- Projects are subject to changes in scope of work due to siting requirements (e.g., underground versus overhead construction) and may become better defined as they mature.
- Projects are consistent with the RTEP horizon year and will change with changes in the system.

Seventy-three projects in the Transmission System Project Listing have costs indicated as "To Be Determined" (TBD). Therefore, the total estimate of RTEP04 Projects is in the range of $1.5 to $3 billion. Cost estimates for projects as well as total costs will be updated at least on an annual basis.

Significant progress made in the plan includes the 39 new projects identified in RTEP04. Table 14.2, Table 14.3, and Table 14.4 provide a summary of the status of the Regional Benefit Upgrade projects, including approved Pool Transmission Facility costs and changes from RTEP03.

TABLE 14.1

Reliability Projects with Estimates Greater than or Equal to $10 Million

RTEP04 Reference	Project Description (may include multiple projects)	Est. costs Millions $	18.4 Approved	15.5/12c Approved	Scheduled I/S Year	July 2004 Status
15.4.2	Southwest Connecticut Reliability Project (Phase I)	200.0	Feb 04	No	2005	Planned
15.4.2	Southwest Connecticut Reliability Project (Phase II)	690.0	No	No	2007	Proposed
15.2.1	NSTAR 345 kV Transmission Reliability Project	217.0	No	No	2006 - 07	Proposed
14.4.1	Northwest Vermont Reliability Project	156.3	Jan 03	Mar 03	2005 - 07	Planned
15.4.1	Southern New England Reinforcement Project	125.0	No	No	2008	Proposed
14.1.1	Northeast Reliability Interconnection Project	90.4	Mar 03	No	2007	Planned
14.5	Monadnock Area Reliability (The Chestnut Hill switch capacitor bank is In-Service - ($3 Million)	76.8	No	No	2006	Proposed
15.4.2	Norwalk Harbor - Northport 138 kV line 1385 replacement	55.0	Dec 02	No	2007	Planned
15.2.2	North Shore - Long Term Alternatives	50.2	No	No	2005 - 08	Proposed
15.2.1	BOSTON Import - Longer Term Alternatives (New Scobie - Tewksbury 345 kV line)	50.0	No	No	2008	Concept
15.2.7	Central Massachusetts Reinforcement (The Carpenter Hill - Millbury V174 line reconductoring is In-Service ($1.9 Million))	36.2	Apr 04	No	2005 - 06	Planned
14.2	Northern New England Transmission Transfer Capability (Deerfield SVC & 391 Loop)	33.0	No	No	2005 - 06	Proposed
15.2.3	BOSTON Area 115kV and Downtown Boston Enhancements	26.0	No	No	2004 - 06	Proposed
14.4.4	Southern Loop Project (Bennington - Manchester - Vernon Rd. 115 kV line)	25.9	No	No	2007	Proposed
15.4.6	Haddam/Middletown Reliability Project (Capacitor banks and Haddam and Branford are In-Service - ($1 Million)	24.5	Aug 03	Dec 03 - Jan 04	2005 - 06	Planned
15.4.7	Eastern CT (Tracy auto and Card breaker)	20.0	No	No	2006	Proposed
15.4.7	Eastern CT Upgrades (Reconductor Tunnel - Ledyard Jct. and upgrade all 69 kV to 115 kV)	18.0	No	No	2012	Proposed
14.4.3	Vermont Northern Loop Project	17.3*	Sep 02	Oct 02	2005	Under Construction
14.3.1	Upgrade both 115 kV lines between Scobie and Schiller: R193, H141, E194, U181	28.0	No	No	2006	Proposed
14.4.6	Granite to Middlesex 230 kV line with necessary substation upgrades	13.4	No	No	2007	Proposed
14.3.4	Tioga Project	12.4	No	No	2005	Proposed
14.1.4	BHE Down East Reliability Improvement	10.6	No	No	2006	Proposed
15.2.8	Rebuild Brayton Point 345 kV GIS Station	10.5	N/R	May 03	2005	Under Construction
15.4.8	New 345/115 kV auto into Barbour Hill area	10.0	No	No	2007	Concept
15.2.4	New 115 kV cable from Mystic - East Boston - K St. substation	10.0	No	No	2007	Proposed
	Sub Total (excluding TBD's)	**$2,006.5 Million**				

* $17.3 Million in new Pool Transmission Facility
$ 5.5 Million in existing non-Pool Transmission Facility

Other RTEP02 Reliability Projects active in the Plan	121.1 Million
Other Regional Benefit Upgrade (Post RTEP02) Reliability Projects active in the Plan.	12.0 Million
Grand Total in the Plan	**$2,140 Million**[23]

[23]May not equal sum due to rounding.

TABLE 14.2

Current Status of Active Reliability Projects in the Plan

Project Status	RTEP02 Projects	RTEP03 Projects	New Projects	Total Projects in the Plan	Estimated Costs[24] ($ Millions)
Conceptual	28	7	16	51	100
Proposed	100	17	21	138	1,443
Planned	34	1	2	37	392
Under Construction	18	2	0	20	206
Total	180	27	39	246	2,140

TABLE 14.3

Progress of Active Reliability Projects in the Plan

RTEP03 Status	RTEP04 Status	Quantity of RTEP02 Projects	Quantity of Regional Benefit Upgrade Projects	Total
Concept	Cancelled	1	0	1
Concept	Proposed	4	5	9
Concept	Planned	0	1	1
Concept	Under Construction	0	0	0
Concept	In-Service	0	0	0
Proposed	Cancelled	5	3	8
Proposed	Planned	20	1	21
Proposed	Under Construction	2	0	2
Proposed	In-Service	1	1	2
Planned	Under Construction	10	1	11
Planned	In-Service	9	0	9
Under Construction	In-Service	13	1	14
	Total	65	13	78

[24] May not equal sum due to rounding.

TABLE 14.4

Active Reliability Projects in the Plan with no Status Change

RTEP03 Status	RTEP04 Status	Quantity of RTEP02 Projects	Quantity of Regional Benefit Upgrade Projects	Total
Concept	Cancelled	27	8	35
Proposed	Proposed	97	11	108
Planned	Planned	14	0	14
Under Construction	Under Construction	6	0	6
	Total	144	19	163

Total from Table 14.3	78
Total from Table 14.4	163
Total number of new projects	39
Projects Placed in service or cancelled	-34
Total active Reliability projects in the Plan:	**246**

15.0 Conclusion

Continued vigilance in monitoring and reviewing forthcoming market responses will be required during the implementation of the recommendations in RTEP04 and the upcoming RTEP05. The same is true for factors that could impact the need or scope of the recommendations made in this report. These efforts will ensure that the RTEP process remains timely and effective in serving the needs of all stakeholders and electricity customers by fostering a robust system, maintaining reliability of service, and enhancing market efficiency. Continued stakeholder input is essential to achieving those ends.

If you have received only the RTEP04 Executive Summary and Summary Report and would like to receive a copy of the RTEP04 Technical Report and Appendices, please call ISO New England Customer Services at (413) 540-4220.

Prepared by

ISO New England Inc.

One Sullivan Road
Holyoke, MA 01040-2841
Customer Service: (413) 540-4220
www.iso-ne.com

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