# Electricity Transmission Infrastructure Development in New England

## *Value Through Reliability, Economic and Environmental Benefits*

**Prepared for:**

**The New England Energy Alliance**

**Massachusetts Affordable Reliable Electricity Alliance**

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# New England Energy Alliance

New England's electric transmission system remains under stress despite recent improvements, many of them significant. The stress is caused by the growing demand for electricity coupled with underinvestment and the unprecedented number of power plants built in the last decade, all needing access to the transmission system. Another major factor is competition in the relatively new wholesale market where transmission plays a vital role.

As a result, significant portions of the system have reached, and may soon exceed, engineering design limits and will need replacing or upgrading. Put another way, without substantial and sustainable investment, the system is on borrowed time.

This paper, sponsored by the New England Energy Alliance and the Massachusetts Affordable Reliable Electricity Alliance, highlights the value and importance of expanding and upgrading the transmission system to maintain reliable delivery and to facilitate the competitive wholesale marketplace. It includes:

- an overview of the region's transmission system including its function in ensuring reliable electricity delivery and its expanding role in the competitive wholesale marketplace;
- the condition of the system and concerns about future operation;
- key system problem areas and the resultant economic impacts on consumers;
- the value of transmission infrastructure and magnitude of investment needed (without promotion/endorsement of any specific project);
- policy issues for consideration to ensure investment is made to maintain reliability and realize the benefits of competition.

We hope you find the paper useful. For more information about the New England Energy Alliance or the Massachusetts Affordable Reliable Electricity Alliance, please visit www.newenglandenergyalliance.org or www.maarea.us

Sincerely,

| | |
|---|---|
| Carl Gustin | Paul G. Afonso |
| President | Executive Director |

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# Introduction and Summary

The region's transmission system today serves two vital roles. Its traditional role is to ensure that bulk quantities of electricity flow with a high degree of reliability from power plants to population centers where the power is needed. Its newer but equally important role is to facilitate the trading and delivery of electricity in the region's wholesale electricity market. Without a reliable and efficient transmission system to move electricity as a tradable commodity, the ability to meet electricity demand reliably and economically is diminished.

The region's transmission owners and ISO New England, which oversees operation of the region's bulk electric power system and administers the wholesale market, are responsible for ensuring the transmission system achieves its dual purpose. Over the past several years, significant progress has been made to expand and upgrade the region's transmission system. But more is needed.

## Serious Challenges Require System Expansion and Upgrades

While ISO New England has maintained the system's reliability, several challenges are limiting the transmission grid's ability to efficiently and economically transmit electricity to meet growing demand. As a result, electricity prices are higher in areas with transmission constraints and ISO has found it necessary to implement operating procedures during periods of peak demand to ensure the reliability consumers have come to expect.

Simply put, the transmission system is not designed for all the demands now being placed on it. There are four basic reasons why this condition exists today:

- *Age and Size:* The system consists of many aging, lower-capacity lines that are undersized for the amounts of electricity that must be transmitted – increasing the risk of equipment failure.

- *High Electricity Demand Levels:* Since 2000, the region's peak demand for electricity has increased 28 percent. Over the next decade, peak demand is expected to increase about 20 percent, which will put additional stress on the system.

- *Infrastructure Underinvestment:* Over the past decade, much of the capital investment spent on regional transmission infrastructure was to interconnect the many new generating plants that were built soon after industry restructuring. While more than $9 billion was spent on new electricity generation, less than $1 billion was invested in transmission infrastructure.

- *Level of Transactions:* Today, more than 300 companies participate in the region's wholesale electricity marketplace – buying and selling electricity –

completing more than $11 billion in transactions annually. The existing transmission system was simply not designed for this level of heavy use. It is akin to transforming a secondary road into a superhighway.

In the absence of significant reinforcement and expansion, the system's reliability will inevitably decline from equipment problems and the inability (or significant limitations) to accommodate the interconnection of new generating facilities. In addition, electricity prices will rise from the inability to transmit lower cost electricity to where it is needed –- undercutting competition and negatively impacting consumers, the economy and the environment.

## Lack of Investment Costs Consumers $1.6B Over 5 Years

The above conditions have resulted in serious "transmission congestion," which means lower cost electricity cannot be transported out of its generation area into an area with high demand.

Since 2003, congestion costs in the region total more than $600 million. In addition, in many constrained areas, "reliability must run" (RMR) contracts are needed to keep otherwise uneconomic generating plants operating because power from less expensive generation cannot be imported to meet demand. For the past five years, total costs resulting from RMR contracts are almost $1 billion.

This combined cost of $1.6 billion from market inefficiency places the region's businesses at a competitive disadvantage and denies consumers hard-earned income.

## Transmission Projects Underway to Increase Reliability

Nevertheless, New England is well ahead of other regions in terms of the establishment and implementation of a comprehensive planning process for transmission infrastructure that engages stakeholders – generators, regulators, transmission owners, consumers and ISO New England.

Several major projects have recently been completed or started to enhance the system. But more investment is needed. ISO New England has identified more than $4 billion (and over 350 individual projects) in additional transmission infrastructure investment primarily to maintain reliability. Additional projects may be necessary to break down remaining system barriers to unfettered trading of the electricity commodity in the competitive marketplace. The major projects that have been completed or started are:

- *NSTAR* – 345 kV substation and two underground 345 kV lines to increase import capability into Boston area completed in 2007.

- *Southwest Connecticut* - Phase I completed in 2006 is a 20-mile 345 kV circuit; Phase II to be completed in 2009 includes a 70-mile 345 kV circuit.

- *Northwest Vermont* – a 36-mile 345 kV line and a 28-mile, 115 kV line to serve northwestern Vermont with completion in October 2007.

- *Northeast Interconnection* - a 114-mile, 345 kV line to increase transfer capability between New England and New Brunswick, scheduled for completion in December 2007.

- *New England East-West Solution (NEEWS)* – will enhance east-west flows of electricity in New England. Specific components of NEEWS include Greater Springfield, Rhode Island, Interstate and Central Connecticut. Project plan to be finalized by end of 2007.

## Cost of Transmission Investment Offset by Economic and Environmental Benefits

New transmission infrastructure enhances system reliability. It can also lower (sometimes significantly) the delivered price of electricity to consumers by opening up the system to greater competition and thereby reducing, or even eliminating, congestion costs. Transmission infrastructure can also provide very significant environmental benefits by increasing access to cleaner, more efficient generating facilities and renewable resources – sometimes enabling the retirement of older inefficient generating facilities.

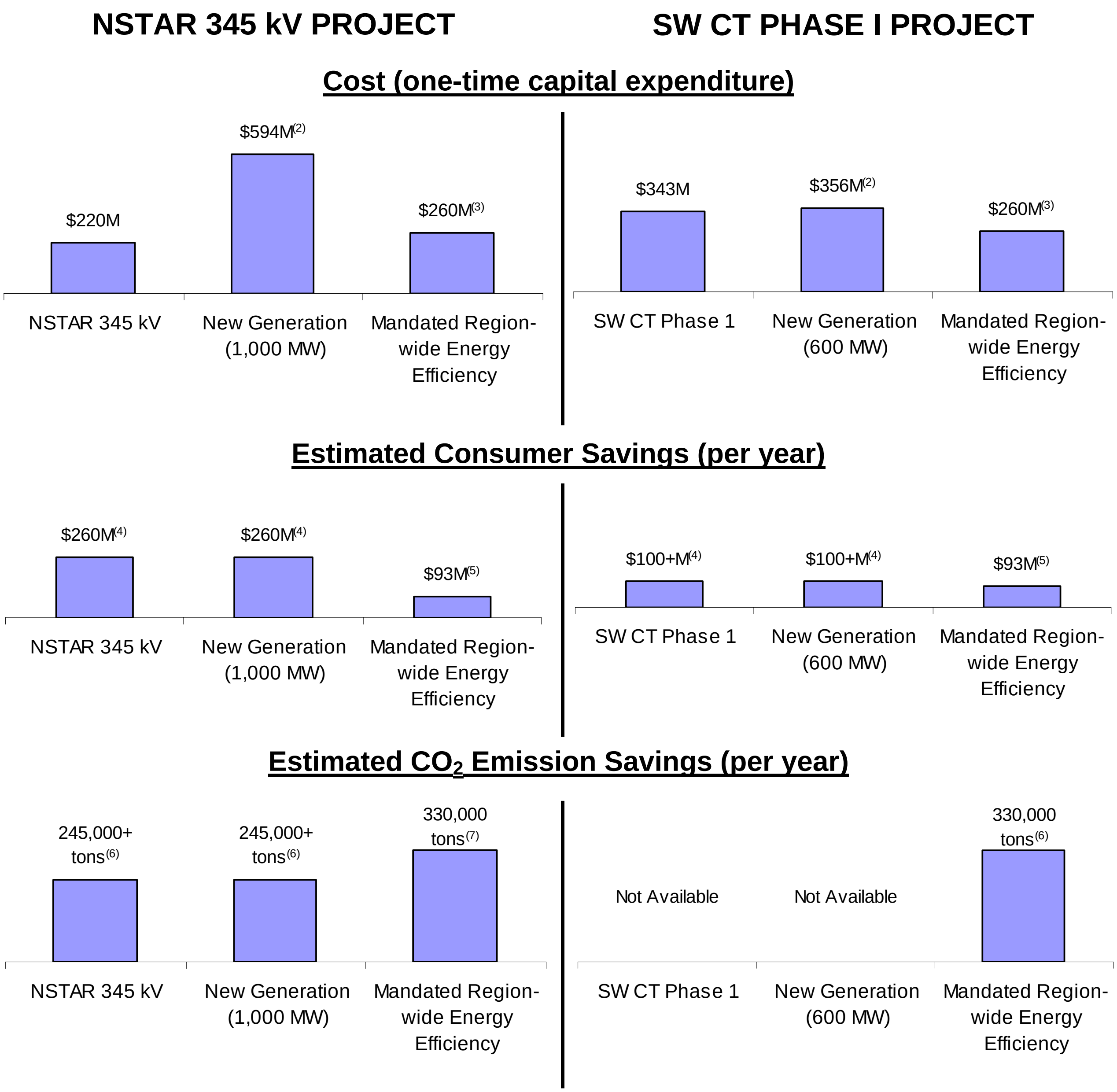
Two recently completed transmission projects – The NSTAR 345 kV project and Phase 1 of the Southwest Connecticut project – highlight these benefits showing that consumer savings can greatly outweigh project capital costs in just a short time -- *and* provide environmental benefits.

To provide perspective on the magnitude of these benefits, Figure 1 compares the approximate economic and environmental value of the transmission projects to two alternatives considered but rejected as neither feasible nor practical.

The first, investing in energy efficiency, while vital to the region, cannot produce the large-scale peak load reductions required to mitigate future potential transmission system overloads. The second – adding a new generator to the constrained areas – would be infeasible because the existing transmission infrastructure is unable to accommodate a new, large generating facility without significant upgrading.

Figure 1 shows that transmission infrastructure projects – in addition to providing system reliability benefits – can provide substantial economic and environmental value by enhancing competition and increasing access to clean generation.

## Figure 1 – The Value of Transmission Projects Compared to Resource Alternatives Deemed Not Feasible[(1)]




[(1)] Alternatives evaluated during the project approval process and were found to be neither feasible nor practical. The comparisons are made to provide perspective on the value of transmission

[(2)] Assumes cost of $594 per kW for a high-efficiency combined cycle of natural gas-fired generating facility (capital cost from U.S. DOE, EIA)

[(3)] Total amount contributed by the region's consumers (mandated charge on electricity bill)

[(4)] NSTAR: Assumes $130 million per year savings in transmission congestion (estimated by NSTAR); $30 million from elimination of RMR agreement for New Boston Unit 1 (being deactivated); partial contribution to elimination of RMR agreements on Mystic Units 8, 9 totaling $289 million (assumed savings contribution of 1/3). SW CT: Assumes $100 million per year savings in transmission congestion (estimated by Northeast Utilities). Potential future mitigation of RMRs totaling $200 million/yr would increase savings further. New generation assumed to provide similar economic benefits.

[(5)] Amount consumers currently save/year from consumer-funded energy efficiency programs (based on annual kWh savings compiled by Northeast Energy Efficiency Partnership)

[(6)] Amount of emissions savings from the closure of New Boston Unit 1 (assumed replacement with high efficiency natural gas-fired unit). New generation was assumed to have similar environmental benefits.

[(7)] Region's emissions savings from consumer-funded programs (based on kWh savings and average regional fuel mix)

## Infrastructure Development Policy Considerations

To ensure transmission reinforcement and expansion is implemented in a timely cost-effective manner, two key issues should be addressed by policymakers to ensure that both reliability criteria and market efficiency requirements are met:

- *Recognize Full Benefits in Planning Process* – to date, the need for transmission projects has been narrowly focused on reliability, but in a competitive marketplace, factors like economic savings, reduced margins due to increased competitive pressures, fuel diversification/RPS compliance, RGGI compliance and commodity trading all need to be prominently considered.

- *Implement Reasonable Siting/Approval Processes* – a major obstacle to transmission infrastructure development has been significant delays during the siting and permitting process which increases project costs and schedules – especially for those involving multiple states.

A third issue – an equitable cost allocation mechanism for new transmission – was negotiated over several years by state regulators, ISO New England, New England Power Pool (NEPOOL) and other stakeholders. The FERC-approved mechanism was designed for the region's tightly interconnected transmission system. Project costs are recovered regionally if determined to have region-wide benefits or locally if projects provide only local benefits. This cost mechanism has been a key driver in the recent surge in cost-effective transmission infrastructure development by providing financial certainty. While not all stakeholders are pleased with the outcome, it is an example of the importance of regional cooperation to address transmission issues.

# I. Overview of Transmission System

New England's electricity transmission system consists of nearly 8,000 miles of transmission lines and supporting equipment. The system transports electricity from the region's 350 generating plants to substations where voltage is lowered and delivered by local distribution companies to consumers.

Unlike other commodities, electricity cannot be stored and must be instantaneously produced and delivered upon demand – making the transmission system as vital as generating plants.

Since the electricity industry was restructured in the late 1990s, its function, operation and management have changed dramatically.

## Infrastructure

For convenience, New England's transmission system can be viewed as a road network – allowing a commodity (in this instance electricity) to be transported to the marketplace in a reliable and unfettered manner.

The region's 2,000 miles of high-voltage 345 kV (and 230 kV) transmission lines are the backbone of the system and are akin to an "interstate highway".[1] These lines transmit large amounts of electricity over long distances from major generating stations with minimal losses or voltage drops.

Approximately 5,500 miles of lower or secondary capacity transmission lines – 115 kV to 69 kV – are the "state highways" of the system, transmitting electricity from the higher voltage lines to substations in geographic load areas and interconnecting smaller generating facilities. From there, utility distribution systems – less then 69 kV – are the "secondary roads" that ultimately deliver electricity to consumers.

Twelve lines interconnect New England with neighboring grids in New York as well as New Brunswick and Quebec, Canada, allowing for the import and export of electricity between regional systems.

The system is a grid network – connecting not only transmission lines from generating plants to load centers, but transmission lines to other transmission lines

[1] The higher the voltage, the more electricity lines can carry. 345 kV transmission lines are the highest voltage lines in New England. The largest capacity lines currently in the U.S. are 500 kV and 765 kV lines. These extra high voltage lines are more common in other parts of the country with more land availability – such as the west – as they require taller pole structures and wider rights-of-way. Overhead transmission line poles or structures in New England are generally between 60 and 140 feet tall. In comparison, distribution line structures are approximately 40 feet tall. Transmission structures can be constructed of metal or wood – single or double poled. They can be single-circuited carrying one set of transmission lines or double-circuited with two sets of lines. Transmission lines can also be buried underground which is more costly.

providing redundancy to ensure the uninterrupted flow of electricity.[2] The interconnectedness of the system, however, means that it is only as strong as its weakest link. In other words, a performance problem in a distant area can propagate through the system and impact reliability in distant areas.

## System Operation and Management

**Regulated Paradigm.** New England's transmission system was incrementally built over several decades by vertically integrated[3] and highly regulated utilities. Interconnections between adjoining utilities and neighboring regions existed – but were only utilized intermittently to maintain reliability and to share excess generation. (The usage of the interconnections was similar to a "mutual aid" system that municipalities employ to assure public safety.) Indeed, each utility was under no legal obligation to allow another utility to transport electricity over its transmission system. It was a situation akin to "private toll roads".

Under the regulated, vertically integrated paradigm, utilities were monopolies building generating facilities and transmission infrastructure to complement each other within their geographic service territory. Moreover, electricity was viewed as a "bundled service" and not as a market commodity subject to trading over the transmission infrastructure. Regulators approved generating and transmission infrastructure and set rates.

The Northeast Blackout of 1965 highlighted the need for operational coordination between the region's utility companies. Accordingly, the New England Power Pool (NEPOOL) was formed as a voluntary organization of the utility companies to direct the minute-to-minute operation of the region's grid to match supply and demand as well as to institute reliability standards and requirements.

The 1965 blackout also prompted creation of the North American Electric Reliability Council (NERC), which established voluntary reliability and operating performance standards across regional grids. (As subsequently discussed, NERC's responsibility and authority was significantly increased subsequent to the 2003 Eastern Electricity Blackout.)

**Restructuring.** The electricity industry began undergoing a substantial change when the Energy Policy Act of 1992 created open transmission access by mandating that all utilities allow other generators the use of their lines. Federal Energy Regulatory Commission (FERC) Orders 888 and 889 further encouraged wholesale

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[2] The region's transmission system also includes: hundreds of substations where transformers increase or decrease electricity voltage; switching stations that redirect the flow of power whenever a fault occurs on the system; and circuit breakers that disconnect the flow of electricity from the faulted equipment to protect and preserve the system from further damage.
[3] Vertically integrated utilities own both generation (produce electricity) and transmission and distribution (deliver electricity).

competition by requiring owners of transmission facilities to provide access on request and on a fair and nondiscriminatory basis.

Within a decade, every state in New England except Vermont enacted legislation to "restructure" retail electricity markets. Under restructuring, utilities were either required or strongly encouraged to sell their generating plants to companies that would operate them in a competitive marketplace. (Utilities remained regulated and responsible for local distribution service.) Regulatory jurisdiction over transmission was split between FERC, with rate setting authority, and state agencies, with responsibility for siting new infrastructure.

A 2006 white paper by the New England Energy Alliance[4] as well as other reports have identified substantial benefits resulting from the operation of generation plants in a competitive marketplace. These benefits have included: significantly improved generating plant performance; substantially lower emission rates even as electricity production increased 25% and, an unprecedented 10,000 Megawatts of new generation construction (transforming the region from an importer to an exporter of electricity) over a several year period. These, along with other factors, led consumers to cumulatively save $6.5 to $7.6 Billion between 1998 and 2005. [5]

Restructuring also profoundly changed the operational demands and management requirements of the grid – as the "patch work" system had to seamlessly and continuously function across the region. In other words, the private roads became public (although a toll could be charged).

**Independent System Operators (ISO)** So called ISO's were created under FERC oversight to implement and administer the competitive, wholesale marketplace to ensure fair and open access as well as reliable operation of the region's transmission system. In 1997, NEPOOL transferred the day-to-day operation and management of the bulk transmission system and generation facilities to ISO New England.

On February 1, 2005 – after a four-year development effort – FERC approved ISO New England's designation as a Regional Transmission Organization (RTO). As an RTO, ISO New England assumed broader authority for the day-to-day management of the region's transmission system and a greater level of independence to effectively administer the competitive, wholesale market.[6]

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[4] "A Review of Electricity Industry Restructuring in New England", Prepared for New England Energy Alliance by Polestar Communications & Strategic Analysis, September 2006.

[5] Estimate based on a comparison of actual retail electricity prices against a projection of where they would likely have trended in the absence of restructuring from 1998 to 2005, by Polestar Communications & Strategic Analysis in above referenced report.

[6] In Order 2000, FERC endorsed the formation of RTOs to ensure greater coordination in planning and operating power grids, improving access to transmission lines that would enhance competition and to develop larger power pools to improve the reliability of the U.S. bulk power system. Under the order, an ISO, a for-profit transmission company, or a combination of these entities can form an RTO.

Under contractual agreements, ISO New England was also granted authority to conduct regional planning and to direct transmission owners to operate their facilities in a manner that maintains system reliability – including the requirement to expand existing transmission lines or build new ones to assure reliability.

**Infrastructure Ownership.** As shown in Table 1, the region's transmission infrastructure is owned by seven companies[7] – most were investor-owned, vertically integrated utility companies prior to restructuring. The exception is the Vermont Transco LLC, the nation's first "transmission only" company formed in 1956 by Vermont's utility companies.

The transmission assets are owned primarily by four companies – Northeast Utilities, National Grid, Central Maine Power and NSTAR. Each of these companies has undergone significant restructuring primarily resulting from the sale of generation assets to focus almost exclusively on transmission and distribution.

**Reliability Organizations.** The August 2003 Eastern Electricity Blackout – involving portions of the mid-west, northeast and the Canadian Province of Ontario – that affected 50 million people highlighted the longstanding fact that grids (which have become increasingly interconnected as a result of technology and restructuring) are only as strong as their weakest links. The blackout prompted federal legislation to make NERC's voluntary standards mandatory and enforceable.

The Energy Policy Act of 2005 authorized the creation of a self-regulatory "electric reliability organization" (ERO) to develop and enforce the standards. In 2006, FERC approved NERC as that organization. The developed standards relate to the planning and operation of the bulk electricity system and cover areas such as: balancing consumer demand with generation supplies, emergency operations, cyber security, vegetation management, and disturbance reporting.[8] As of June 2007, U.S. utilities and other bulk electricity industry participants that violate any reliability

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Today, there are five ISO/RTOs in the United States besides ISO New England including: California ISO, Electric Reliability Council of Texas, Midwest ISO, New York ISO, PJM Interconnection and the Southwest Power Pool.

[7] By comparison, more than 35 companies own/operate the region's 350 generating plants.

[8] NERC's mission is to improve the reliability and security of the bulk power system in North America. NERC develops and enforces reliability standards; monitors the bulk power system, evaluates adequacy annually via a 10-year forecast and winter and summer forecasts; audits users, owners and operators for preparedness; and educates, certifies and trains industry personnel. NERC's definition of reliability encompasses two concepts: adequacy and security. Adequacy is defined as the "ability of the system to supply the aggregate electric power and energy requirements of the consumers at all times" while security is defined as "the ability of the system to withstand sudden disturbances". Adequacy implies that there are sufficient generation and transmission resources available to meet projected needs plus reserves for contingencies; security implies that the system will remain intact even after outages or other equipment failures.

standard requirements will face enforcement actions and fines of up to $1 million per day.[9]

| **Table 1**<br>**New England Transmission Infrastructure Owners** | | | | | |
|---|---|---|---|---|---|
| **Owner** | **Approximate Miles of Transmission Lines** | | | | **Total** |
| | **High Voltage** | | **Lower Voltage** | | |
| | **230 kV** | **345 kV** | **115 kV** | **69 kV** | |
| Northeast Utilities<br>(>2 million customers in CT, MA, NH) | 8 | 766 | 1,853 | 40 | 2,667 |
| National Grid<br>(1.7 million customers in MA, NH, RI) | 367 | 385 | 1,247 | 329 | 2,328 |
| Central Maine Power Co.<br>(600,000 customers in central and southern Maine) | ------ | 184 | 933 | ----- | 1,117 |
| NSTAR Electric<br>(1.1 million customers in Massachusetts) | 35 | 235 | 445 | ---- | 715 |
| Vermont Transco, LLC | 32 | 79 | 378 | 10 | 500 |
| United Illuminating<br>(320,000 customers in CT) | ----- | 6 | 111 | ----- | 117 |
| Bangor Hydro Electric Co.<br>(115,000 customers in eastern Maine) | ----- | ----- | 80 | | 80 |
| Other (municipal electric utilities) | ---- | ---- | 51 | ---- | 51 |
| Total | 442 | 1,655 | 5,098 | 379 | 7,575 |
| Source: ISO New England, Pool Transmission Facilities as of January 1, 2007. | | | | | |

[9] The requirements for ensuring the reliability of New England's bulk power system reflect standards developed by NERC, NPCC and ISO. These requirements are codified in the NERC standards, NPCC criteria and the ISO's operating procedures.

**Contemporary Grid Requirements.** Notwithstanding new (and mandated) standards imposed by NERC and other organizations, an assessment of the region's grid must be performed through a prism that allows its function to be viewed as two separate, but necessary components:

- providing traditional reliability of an essential energy source; and

- facilitating market performance to allow for effective and efficient trading and delivery of a commodity (thereby achieving the intended benefits of restructuring).

The component that has traditionally received the most attention has been reliability. The region's transmission system is sized to meet the highest level of electricity demand – which typically occurs during an extended heat wave.

A robust, reliable transmission system is fundamental to supporting voltage stability, stabilizing the grid after transient impacts, reducing reserves required for secure operation, and facilitating the scheduling of equipment maintenance. Even relatively small failures of the grid can negatively impact the region's quality of life and competitiveness in the global marketplace.

The other component is the system's ability to provide efficient transportation of electricity from its place of generation to the marketplace – which may be many hundreds of miles apart – and to enable the effective operation of competitive wholesale electricity markets. Viable and vibrant wholesale market competition is dependent on: the ability of electricity suppliers to have fair access to the transmission system; the adequacy of the transmission infrastructure to deliver electricity; and for buyers to be able to choose the least expensive wholesale electricity available.

Today's electricity consumers require a complex, integrated and well managed transmission infrastructure that ensures grid reliability to meet traditional utility obligations while at the same time facilitating the operation of competitive electricity markets.

# II. Infrastructure Condition and Capability

In the decade leading up to and the years immediately following restructuring, there was region-wide – and national – underinvestment in the replacement and upgrading of existing transmission infrastructure. There are several reasons for this, most notably: uncertainty about restructuring's requirements and investment cost recovery; challenging siting and approval requirements; and changes in system operations resulting from competitive wholesale electricity generation.

## Aging Hardware and Reliability Effects

**Over-Extended Lines.** As will be detailed in Section IV, there has been substantial progress in reinforcing New England's transmission infrastructure, but the system still consists of hundreds of miles of aging and undersized lines.

The majority of the system was constructed during the 1960s and into the early 1970s and its substations, wires, towers and poles are therefore on average more than 40 years old. This aging infrastructure creates many challenges including the procurement of spare parts and the obsolescence of older equipment.

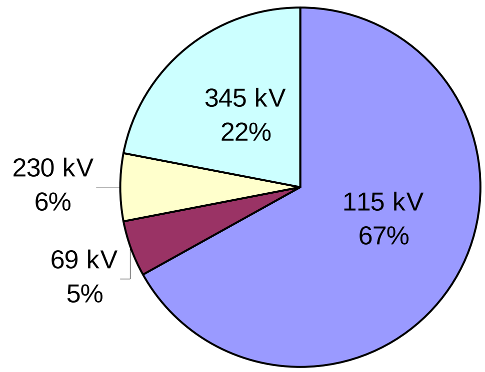
This overall condition is not unique to New England. The U.S. has a transmission system with 1950 and 60s equipment that is delivering electricity to businesses with 21st century technology.[10] According to the Department of Energy, 70 percent of U.S. transmission lines and transformers are 25 years or older and 60 percent of circuit breakers are more than 30 years old.

In addition, as shown in Figure 2, almost 70 percent of the region's transmission system is composed of lower capacity 115-kV lines – many of which were originally designed for 69kV and upgraded through the years.

These lower capacity transmission lines serve a vital "feeder" function throughout the region. Many larger 345/115kV transformers (which are also aging) and generating stations are connected to these lower capacity lines.

[10] "Electricity – a National Perspective", quote from Luther Dow of the Electric Power Research Institute.

**Figure 2 – Major Portion of New England Transmission System Composed of Low Capacity Lines**




Source: ISO New England, Pool Transmission Facilities as of January 1, 2007.

While ISO New England has successfully managed the transmission system's reliability, it does not change the fact that aging hardware and systems with limited capacity are being asked to do more. These conditions have imposed constraints on the system's ability to transmit electricity efficiently and increased the need for system procedures to maintain reliability during peak demand periods. In many locations, the system has reached its designed operating limits.

**Potential System Limitations.** Thermal limitations restrict the capability of a transmission line or transformer to carry electricity. Under normal operations, transmission lines resist the flow of electrons through them, causing heat to be produced. The heat's magnitude is dependent on the amount of electricity flowing through the line as well as ambient weather conditions which effect its dissipation.

When transmission lines are overloaded the resultant overheating can lead to a loss of physical strength. This can reduce the line's expected service life or lead to physical expansion and sagging which causes outages and fires.[11] In the event of equipment failures, the transmission system can usually be isolated in terms of the geographic area affected (which can be very substantial) – but continuing reliability will diminish if not upgraded or replaced. ISO New England has special operating procedures in place that address a variety of such contingencies.[12]

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[11] This condition was a key factor in the chain of events that led to the 2003 blackout.

[12] One such procedures calls for specific actions to be taken to protect the integrity of the system when a system emergency such as unacceptable voltage conditions or a transmission emergency occurs. Any failure on the grid must be instantly isolated. Failure to do so will cause it to cascade throughout the entire grid similar to a domino effect. The most common way to protect the system is via brownout or rolling blackouts (taking turn disconnecting blocks of customers).

Voltage must be maintained within a prescribed bandwidth to ensure proper operation of electrical equipment and to supply adequate voltage to consumers. Fluctuations can and often occur due to variations in electricity demand and to failures of isolated transmission and distribution lines. If the maximum voltage of a system is exceeded, short circuits, radio interference and so called noise can result. In more extreme cases, transformers and other equipment at substations may be damaged or even destroyed. Low voltage on the other hand, causes inadequate operation of electronic equipment and can impact grid stability.

While most power quality issues are found to be on the "customer side of the meter" or are distribution system related, large industrial customers often have electricity supplied directly from 115 kV transmission lines. Nation-wide, power quality that does not meet the demand of today's high technology applications causes economic losses estimated at about $120 billion per year – mostly from disruption of sensitive computerized operations.[13]

## Post –Restructuring Transmission Infrastructure

**Under Investment.** From a broader perspective, much of the capital that has been invested in regional transmission has been dedicated to interconnecting new generating plants that were built in the immediate period after restructuring.

Thirty-five generating facilities were constructed between 1999 and 2006 - providing more than 11,600 MW of new capacity in the region. Prior to restructuring, no such quantity of generating plants had been built and brought to commercial operation over such a short period of time – in this case increasing the region's electricity supply by about 30%. While more than $9 billion was spent on the construction of new generating facilities during that timeframe, less than $1 billion was invested in transmission infrastructure.

Limited transmission infrastructure investment is not unique to New England. A survey conducted by the Edison Electric Institute shows that the U.S. industry construction expenditures for transmission declined from 1975 through 2000 at a rate of $117 million per year. Fortunately the survey also shows that annual transmission investment has been increasing since this period. [14]

The integration of new generating facilities in New England's existing system has challenged a transmission network that was originally intended to serve approximately 20,000 to 25,000 MW of electric load – not the most recent peak load of about 28,000 MW.

[13] "Electricity – a National Perspective", information from Electric Power Research Institute.
[14] "EEI Survey of Transmission Investment", Historical and Planned Capital Expenditures", Edison Electric Institute, May 2005.

As a result, significant upgrade of the region's high voltage 345 kV network as well as many lower capacity transmission facilities is required.

**Future Requirements.** New England is a summer-peaking system. In other words, the highest demand for electricity occurs during hot weather (primarily because of air-conditioning). Since restructuring began a decade ago, the region's peak demand has increased 28% -- causing much of the transmission system's excess capacity to be used up to maintain reliable (which does not necessarily mean efficient) delivery of electricity.

Going forward, ISO New England projects that New England's summer peak demand will grow at a compounded annual growth rate of 1.9 percent - requiring the equivalent of a new 500 to 600 Megawatt (MW) generating plant every year.

In short, over the next decade, the region's transmission grid must increase to have sufficient capacity (plus some excess margin for unforeseen circumstances) to deliver 20% more electricity on peak demand days. While the entire grid does not have to increase in size, significant portions do. In addition, the potentially increased reliance on renewable generation (in particular wind farms), which are typically located in remote areas, will also drive changes to the grid's design and expansion (see next section for a more detailed discussion).

Essentially, the grid's high degree of reliability is on borrowed time without substantial and sustained investment. Action is needed now as transmission investment can be a lengthy process, as the siting, permitting, construction and testing a 345 kV transmission line can take about five or more years (as described in Section V).

# III. Market Dynamics & Consumer Impacts

In addition to the significant transmission infrastructure challenges facing the region, market-related drivers and initiatives are also impacting system operation. System constraints have resulted in congestion that has decreased the ability to transmit electricity to meet demand in many locations. This makes the competitive market inefficient, which in turn causes consumers to pay higher electricity prices.

## Ongoing Impacts on Transmission Infrastructure

**New Generating Plant Locations.** For perspective, in 1971 when NEPOOL was formed, its members consisted of 100 investor-owned and municipal utility companies. Today, more than 300 companies and entities participate in the region's wholesale electricity marketplace – buying and selling electricity – completing more than $11 billion in transactions annually. These transactions also include electricity that is exported to and imported from adjoining regions. As it stands today, the region's transmission system was not designed to handle such a high volume and diversity of transactions.

In addition, the construction of generating plants since restructuring is no longer undertaken by utilities to serve their customers within defined service territories. The seamless delivery of electricity (the commodity) to load centers (the marketplace) from newly constructed generation is much more dependent on the robustness of the transmission system. In a sense, transmission capacity is a measure of the ability of market participants to trade freely – which brings greater efficiency and potential savings to consumers.

Generally, the location of the new plants within the region has been influenced by factors other than the need to meet consumer demand and include: site availability/costs, availability of fuel (typically natural gas), proximity of large bodies of water for cooling, and the cost of local labor.

For instance, Maine has the lowest construction labor rates and land costs in the region, and has sufficient access to fuel (natural gas). As a result, substantial new plant capacity has been built in Maine and therefore located up to hundreds of miles from the "load centers" of Massachusetts and Connecticut. Because the construction of north-south transmission capacity has lagged market development, electricity sometimes becomes "bottled up" in Maine during peak periods and cannot be sent to where it is demanded. Therefore, from a minute-to-minute reliability standpoint, some generating plants are not optimally located.

As subsequently discussed, ISO New England has taken steps – through rules and procedures – for the market to send appropriate price signals and provide adequate compensation for constructing generating plants when and where they are needed most. These steps would help optimize the location of new generating plants vis-àvis demand areas, but will likely be more effective in initiating the timely construction of new generation. The competitive marketplace will still, however, inherently require a robust transmission infrastructure to allow free trading both within and outside the region.

**Environmental Programs.** There are other market forces and government initiatives coming into play that will influence the location of new generation and increase demand on the transmission system.

One example is the Regional Greenhouse Gas Initiative (RGGI) signed by all six New England states and three Mid-Atlantic states, which will result in the development of a common strategy for controlling greenhouse gas emissions from electricity generation.

Beginning in 2009, the initiative essentially seeks to reduce greenhouse gas emissions by 10% from their present levels from the generation of electricity within the participating states.

To comply with these RGGI goals, major changes to existing electricity supply infrastructure will be required, including the construction of significant amounts of new renewable and natural-gas fired generation. In fact, up to 20% of the region's future installed generating capacity could be in the form of large wind farms (the most viable renewable technology currently available) – which would likely be located off-shore or in remote inland locations and therefore substantially away from load centers.[15] The current overall configuration and capacity of the region's transmission system is not prepared to deal with such a change.

Another example is market forces. Increasingly, consumers simply want to purchase "green power". In response, local distribution companies (as well as competitive energy providers) are indirectly sponsoring the development of renewable generation facilities by offering green electricity to consumers. Also, most of the New England states have included renewable portfolio standard (RPS) provisions in their restructuring laws to require that a specified percentage of electricity be provided by renewable generation.

These environmental drivers, which are growing, will require a transmission infrastructure that is configured differently than today. Otherwise, such green programs will falter.

[15] "The Role of Nuclear Energy in Reducing $CO_2$ Emissions in the Northeastern United States", prepared by Polestar Applied Technology, Inc. for the Nuclear Energy Institute, May 2005.

## System Congestion

**Reliability and Market Efficiency Impact.** Congestion occurs when constraints on the transmission system prevent the delivery of electricity from a generating plant to the load center. Restrictions can include instances where transmission lines may not have enough capacity to carry all the electricity – or when operational actions created to protect the security and reliability of the system grid prevent needed transmission delivery.

Generating facility owners in areas with transmission constraints have the ability to exercise market power. Essentially, they can artificially raise electricity prices to consumers during periods when high demand for electricity exceeds local supply sources. The lack of adequate transmission capacity into these areas reduces the ability of all generation to reach load. Such conditions restrict consumer choice. Moreover, they can create a market where consumers are underserved and pay higher prices.

The Energy Policy Act of 2005 directed the Secretary of Energy to conduct a nationwide study of electric transmission congestion every three years. The first study, published in August 2006, examined transmission congestion and identified constrained transmission paths in many areas of the country.[16]

The study designated three levels of congestion:

- **critical**: areas where it is critically important to remedy existing or growing congestion problems;

- **concern**: areas where a large-scale congestion problem exists or may be emerging;

- **conditional**: areas where significant congestion would result if large amounts of new generation resources were to be developed without simultaneous development of associated transmission capacity.

Six locations in New England were identified as having "congestion areas of concern" which are listed below in no particular order.

- New Brunswick to Maine Interface[17]

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[16] "National Electric Transmission Congestion Study", U.S. Department of Energy, August 2006 – the first congestion study in response to the law. The study was undertaken to identify areas of the nation where congestion is a matter of concern, focusing on ways in which congestion problems might be alleviated. Where appropriate in relation to these areas, the Department may designate national interest electric transmission corridors.

[17] A transmission interface is a connection between two systems – between states, regions or countries (Canada).

- Maine-New Hampshire Interface
- Boston
- Southern New England -- East-West Interface
- Southwest Connecticut
- Northwestern Vermont - New Hampshire Interface

These areas have been known and studied by ISO New England and the transmission companies for years and are described below. (Table 3 in Section IV lists the major projects undertaken to upgrade the system in these areas.)

**Northern New England Network.**[18] The Northern New England transmission network consists of a limited number of 345 kV transmission facilities and relatively old 115 kV lines that are geographically dispersed throughout Maine, New Hampshire and Vermont. As a result, this region faces thermal and voltage performance issues and stability concerns and is reliant on several special protection systems. The most significant challenge is to maintain the general performance of the long 345 kV system and the reliability of supply to meet demand. Specific areas of concern include:

- *New Brunswick to Maine:* A single 345 kV interconnection between New England and New Brunswick leads into a 345 kV system in Orrington Maine – that spans hundreds of miles and eventually ties into Massachusetts – is limited in capacity and requires strengthening.

- *Maine - New Hampshire Interface:* Over the last several years, the addition of 3,000 MW of new generation in Maine and New Hampshire – combined with the area's limited transfer capability – has significantly stressed northern New England's export capability. There is insufficient capacity available to transmit southward – resulting in "locked-in" generation resources in Maine. This is contributing to an increasing number of stability and voltage-related constraints – and reduced opportunities for other areas/states to benefit from more efficient sources of generation.

- *Vermont and other Northern Areas:* Rapid load growth has increased demand for electricity in northwestern Vermont; the southern and seacoast areas of New Hampshire and Maine; and the tri-state "Modnadnock" area of Southern Vermont, Southwestern New Hampshire as well as north-central Massachusetts. The network of long 115 kV lines in these areas is limiting the system's ability to efficiently and effectively serve load as well as integrate recently built generation.

[18] "2006 Regional System Plan", ISO New England, October 26, 2006.

According to ISO New England, eliminating constraints and improving the technical performance of this transmission network will become increasingly important as the demand for electricity and the need for fuel diversity in the region increases.[19]

**Southern New England Network.** [20] The 345 kV system in southern New England is the primary infrastructure that connects it to northern New England, and the Maritimes Control Area with the rest of the Eastern Interconnection. [21] This network integrates a substantial portion of the region's generation resources.

According to ISO New England, this network faces thermal, low-voltage, high-voltage, and short-circuit concerns. The most significant concern is the ability to maintain the reliability of supply to serve load and develop the transmission infrastructure to integrate generation throughout this area.

- *Southwest Connecticut.* Portions of this area are not connected to the region's 345 kV system, relying on an older, lower-capacity 115 kV system to serve electricity demand. The system in this area is unequivocally being overtaxed and is no longer able to effectively serve load and support generation.[22] These weaknesses include import constraints, frequent transfer constraints between sub-areas and overall insufficient transmission capability.

- *Boston Area (and other parts of Massachusetts).* The Boston area has had a history of thermal and voltage concerns. But the most significant has been maintaining the reliability of supply to serve load and to integrate generation. Increasing reliance on local generation, imports, demand response efforts or a combination of all three has been needed to maintain system reliability. In addition, there are thermal and voltage concerns in the Cape Cod area because of projected high electricity demand growth, as well as reliability issues in southeastern and western Massachusetts.

- *Southern New England East-West Flows.* This East-West interface approximately follows the Vermont border down through Central Massachusetts to the Connecticut border. It can limit economic transfers of electricity from the east to load centers in the west. Under heavy load periods

[19] Analyses performed to assess the future security of the transmission system are beginning to indicate further reliability needs within Maine and New Hampshire that may require additional and more significant transmission system reinforcements.
[20] 2006 Regional System Plan", ISO New England, October 26, 2006.
[21] There are three major interconnections and eight reliability councils in the U.S. under the oversight of NERC. The Eastern Interconnection connects the transmission systems over most of Eastern North America extending from the foot of the Rocky Mountains to the Atlantic seaboard. The Eastern Interconnection is tied to both of the other 2 major interconnections (Western and Texas) and to Canada. These interconnections are designed to allow neighboring systems to share generation and voltage stability resources providing mutual benefits when needed. Tying power systems together also introduces risks that a single disturbance can collapse all of the systems tied together.
[22] As discussed in the next section, the first phase of a very substantial 345 kV line construction has been completed by Northeast Utilities and has alleviated some of the problems.

with generation outages in the west, this interface could affect the reliability of portions of New England. As electricity demand increases, future conditions will result in transmission line overloads, and voltage and security violations on the high-voltage systems in Massachusetts, Rhode Island and Connecticut.

## Consumer Impacts

In terms of a competitive market, the costs of congestion and other transmission limitations can be significant and are almost always borne by consumers through higher commodity prices, restricted competition, and even potential supplier exploitation of market power.

**Increased Retail Price.** Congestion increases electricity prices regionally and locally because either the least-cost electricity cannot be transported out of its generation area (the previously mentioned termed “bottled power” which influences regional prices) or imported into an area with high electricity demand (termed a “load pocket” which influences local prices) or both.

Historically, there have been significant transmission limitations between exporting and importing regions in New England. Exports from Maine to the south, for example, are frequently limited by transmission constraints, while Connecticut and Boston have often been unable to import enough to satisfy demand without dispatching expensive local generation.

Incentives to eliminate the transmission barriers to free trade took place in 2003, as ISO New England implemented market changes that included the establishment of “locational marginal pricing” – an approach that divided the region into eight zones.[23] Locational marginal pricing (LMP) recognizes that the transmission system can become congested during times of peak or even moderately high demand making it more expensive to deliver electricity to some specific geographic areas.

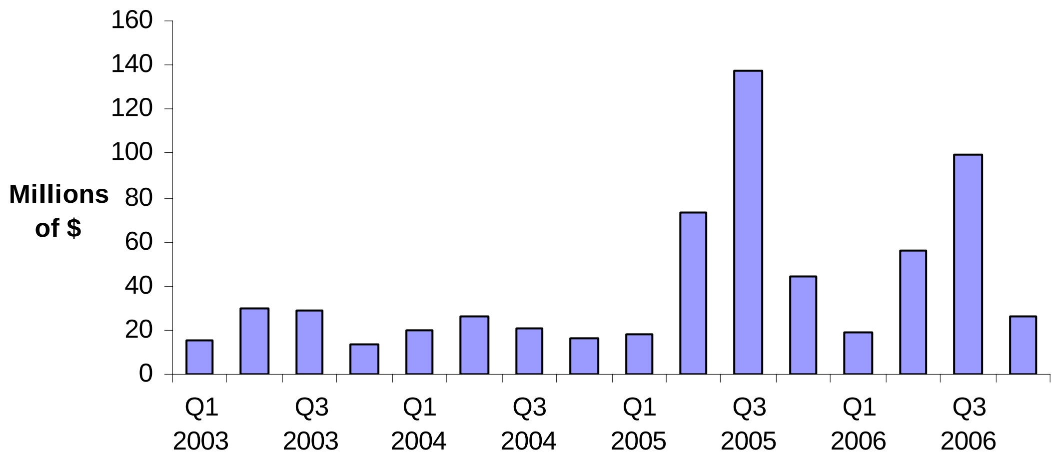
Essentially, congested areas may not be able to receive the least cost electricity that is available because of transmission constraints or barriers to trade. In some instances, higher cost electricity can be transmitted or, as discussed below, expensive electricity must be produced within the congested area from older and less efficient generating plants. LMP’s also reflect the costs of transmission losses – inherent throughout any system because of resistance in transmitting electricity through wires –- which can be greater than normal when aging, undersized 115 kV lines are utilized.

[23] Connecticut, Maine, New Hampshire, Rhode Island, Vermont, Western and Central Massachusetts, Northeastern Massachusetts and Boston, Southeastern Massachusetts and Cape Cod.

Previously, such expenses were distributed among all consumers in the region. Now, these prices reflect the true cost of delivering and supplying electricity at every location on the grid, with the intent of providing incentives for the construction of new transmission infrastructure and generating facilities in those areas where they are most needed.

Figure 3 shows regional congestion costs by quarter since LMP was initiated in 2003 – cumulatively totaling an expense of more than $620 million to consumers. Not unexpectedly, in all years, the highest amounts of congestion typically occur during the third quarter or summer when electricity demand is highest.

**Figure 3 – New England Transmission Congestion Costs**



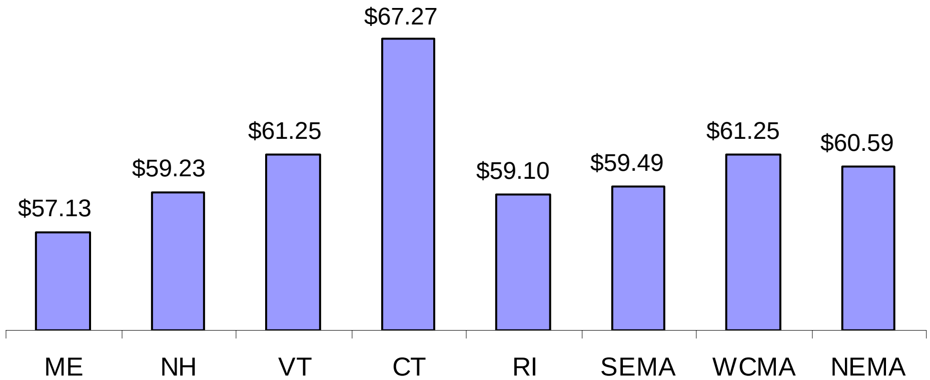

Source: ISO New England, "2006 Annual Markets Report", June 2007.

Figure 4 shows that in 2006, LMPs were similar across all the load zones with the exception of Maine and Connecticut. This dichotomy highlights the current inefficiency of the region's transmission system.

The average price difference between these two states in 2006 was $10.14/MWh, or about 18% (as discussed previously, a large number of generating plants have been built in Maine with inadequate transmission lines to bring the electricity to market). During high demand periods, Connecticut has been import constrained, causing congestion and higher prices. This problem is exacerbated through high transmission losses – as a result of insufficient generation with weak infrastructure.

**Figure 4 – Average New England Wholesale Electricity Price by Zone in 2006 ($/MWh)**

**Transmission Constrained Areas Have Higher Prices**




Source: ISO New England, "2006 Annual Markets Report", June 2007.

High congestion costs, however, are not unique to New England. In the PJM Interconnection area, for example, total congestion costs were ~$2 billion in 2005 and $1.6 billion in 2006 (but PJM covers a larger area than New England including 13 states and the District of Columbia, serving a population of about 51 million – almost 4 times the population of New England).[24] The New York ISO in 2005 alone reported $990 million in congestion costs for New York State.

DOE has designated parts of New York and portions of the PJM area as being "critical congestion areas" potentially requiring billions of dollars of investment in new transmission and generation over the next decade.[25]

**Reliability Must Run (RMR) Agreements.** Subject to FERC approval, RMR contractual arrangements provide financial support to companies owning facilities that are uneconomic to operate, but essential to maintain reliability.[26]

The agreements reflect a determination by the ISO that the system requires the operation of certain generating units to maintain reliability because of transmission constraints or for voltage support, operational reserves, or other reliability reasons. The vast majority of RMRs are in load pocket areas because transmission

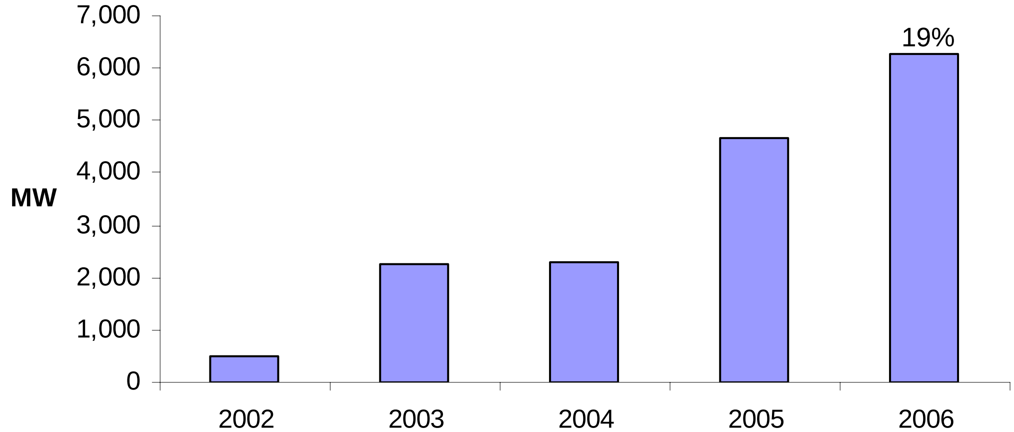
[24] "PJM Interconnection 2006 State of the Market Report", 2007.
[25] "National Electric Transmission Congestion Study", U.S. Department of Energy, August 2006.
[26] Reliability Agreements are out-of-market compensation for generation service to ensure key capacity remains available. They are intended as interim measures that provide a mechanism for power plant owners to recover fixed costs for capacity the ISO requires to ensure reliability – until the affected generator is replaced by a competitive alternative – or by increased transmission transfer capability.

constraints prevent less expensive generation from being imported to meet local demand.

RMR contracts undermine the market by providing a regulated cost recovery option to some generators and not others. These contract agreements have been on the rise in the import constrained areas of Connecticut and Boston (NEMA). As of December 2006, 41% (3,082 MW) of the total generating plant capacity in Connecticut and 41% (2,213 MW) of the capacity in NEMA (Northeast Massachusetts) were under RMR agreements. System-wide, 19% (5,843 MW) of the region's capacity was under RMR agreements. As might be expected, given the above discussion, Maine, Vermont, New Hampshire and Rhode Island do not require RMR agreements.

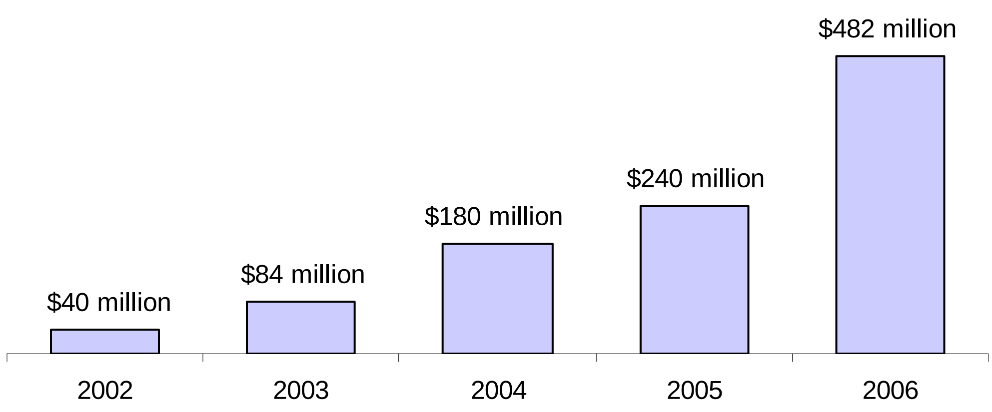
Figure 5 shows the increase in generating capacity under RMR agreements since 2002. Between 2005 and 2006, the total capacity under reliability agreements increased by 24%. Figure 6 shows that total cost of the RMR agreements since 2002 of approximately $1 billion.

**Figure 5 – New England Capacity Under Reliability Must Run Agreements (RMRs)**
**(Total System Capacity 30,895 MW)**




Source: ISO New England, "2006 Annual Markets Report", June 2007.

**Figure 6 – New England's Increasing Costs for Reliability Must Run (RMR) Agreements**




Source: ISO New England, "2006 Annual Markets Report", June 2007

# IV. Infrastructure Development & Economic/Environmental Value

New England is well ahead of other regions in terms of the establishment and implementation of a comprehensive planning process for transmission infrastructure that engages the stakeholders. This process has resulted in a surge in infrastructure investment with many major transmission projects either completed or underway, but with many more needed. Recently completed projects highlight the value – in addition to reliability — that transmission infrastructure provides, demonstrating that costs are quickly offset by benefits.

## Planning Process

**ISO Planning Requirements.** Each year, ISO New England develops a comprehensive Regional System Plan (RPS) – a ten-year plan that contains forecasts of future loads and how the system will meet the demand – through the addition of generation resources, demand-side resources and transmission infrastructure.

The plan is developed with the participation of "stakeholders" including generators and transmission owners, governmental representatives, state agencies, representatives of local communities and consultants – and is a comprehensive electrical engineering assessment composed of numerous studies and analyses of New England's bulk electric power system.[27] The RPS identifies system needs and provides opportunities for market solutions (generation, DSM, merchant transmission). If those solutions are not undertaken, a regulated transmission plan is prepared as a reliability backstop.

Types of transmission upgrades can include: reliability projects (needed to meet reliability standards); interconnection projects (to connect generation); economic projects (to provide reduction in cost to supply system load); and elective upgrades (sponsoring entity may have their own justification for project). Transmission projects to date have been undertaken for reliability or interconnection purposes.

**Cost Allocation/Incentives.** ISO New England has also developed a process to determine New England-wide cost allocation for transmission projects. The process requires transmission companies (see Table 1) to submit an application for a project including its impact on system reliability and its consistency with engineering design and construction practices.

[27] ISO New England uses a comprehensive model of the power system for conducting transmission studies that include data on 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. System assessments and planned improvements are coordinated with neighboring control areas.

Subsequently, ISO New England, with input from its Reliability Committee – a group of market participants who provide advice about the design and oversight of reliability standards – determines the project's cost allocation. Costs associated with a transmission project that are found to improve overall regional system grid reliability are shared across the six-state region. While those associated with meeting localized needs are borne by the area in which they occur.

Since its implementation in 2004, fifty-five transmission upgrades across the region have been evaluated through this methodology. Moreover, this FERC-approved cost allocation process increases the certainty that planned projects will proceed.

To encourage further transmission investment in New England, FERC, in November 2006, authorized a return on equity for transmission owners along with an incentive rate for transmission expansion. The incentive was designed to bring transmission projects on line in a timely manner – and is applied to projects identified to be necessary by ISO New England. [28]

## Transmission Investment

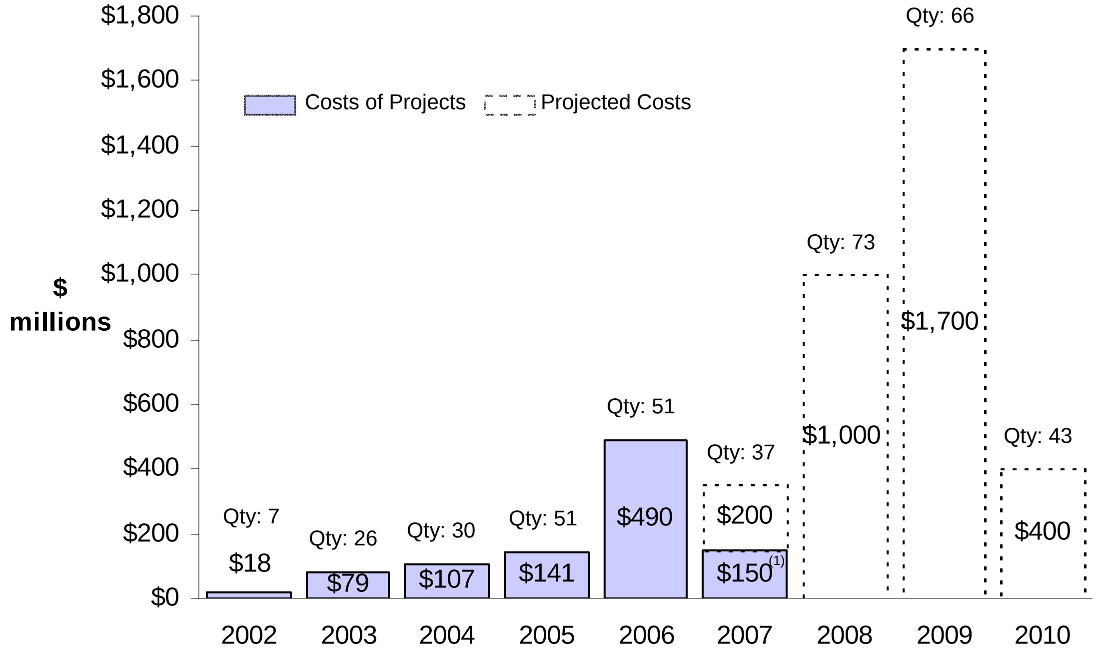
Significant progress has been made in upgrading the region's transmission infrastructure since ISO's regional planning and cost allocation processes were implemented. From 2002 through June 2007, 182 projects have been placed in service representing an investment of more than $974 million (see Figure 7).

In addition to those projects, ISO New England has identified more than $4 billion in additional transmission investment for transmission lines, substations and other equipment to maintain the reliability of the regional power system.

Table 2 provides an overview of the status and costs of the region's active transmission projects – all identified to be needed for reliability. As shown, the most significant projects are under construction (based on the cost per project), but scores of smaller ones remain to be initiated throughout the region.

[28] Initially, a 12.8% base return on equity was approved; however, it was later lowered to 11.4% – resulting in $32 million in consumer refunds.

## Figure 7 – Increasing Investment in New England Transmission (through 2010)




(1) Costs as of October 2007

Note: Numbers above bars represent project quantities.

Source: ISO New England, "Regional Transmission Project Update", October 2007.

| Table 2<br>New England Reliability Transmission Projects | | |
|---|---|---|
| **Project Status** | **Total Number** | **Estimated Cost** |
| Conceptual | 81 | $442 million |
| Proposed | 164 | $1,238 million |
| Planned | 62 | $358 million |
| Under Construction | 47 | $2,347 million |
| **Total** | **354** | **$4,385 million** |
| Source: ISO New England, "Regional System Plan Transmission Projects", October 2007 Update. | | |

Table 3 lists the major projects completed or underway to address the region's congested areas identified by DOE and ISO New England.[29] They include five major 345 kV projects that have been approved and sited in four states – two of which are now in-service – as well as one under consideration and a study that is underway.

[29] These projects are also included in Table 2.

**Table 3**
**Summary of Major New England Transmission Projects and Studies Completed/Underway (345 kV)**

| Congestion Area | Transmission Project/Study |
| --- | --- |
| **Projects Completed in 2006/2007** | |
| Boston | *NSTAR 345 kV Reliability Project* – improves the reliability of the Greater Boston area by increasing import transfer capability by about 1,000 MW (or by about 28%). The project included the construction of a 345 kV substation and the installation of two underground 345 kV lines. The first phase of the project was completed in 2007. Phase two will add a third line --- expected to be installed in 2008. Transmission Owner: NSTAR |
| Southwest Connecticut | *Southwest Connecticut Reliability Project* – addition of 345 kV line to improve the transfer of power and system performance in Southwest Connecticut: Phase I included a 20-mile 345 kV circuit from Bethel to Norwalk completed in October 2006. Transmission Owner: Northeast Utilities, United Illuminating |
| **Projects Underway** | |
| New Brunswick to Maine | *Northeast Reliability Interconnect Project* – a new 144-mile, 345 kV transmission line between New England and New Brunswick to improve the transfer capability between the two regions by 300 MW and improve system performance in northern Maine. Projected in-service date is December 2007. Transmission owner: Bangor Hydro |
| Northwest Vermont | *Northwest Vermont Reliability Project* – includes a new 36-mile 345 kV line and a 28-mile 115 kV line and associated equipment to serve the major load center in northwestern Vermont. Portions of the project completed in 2006/2007 with total project completion scheduled for 2008. Transmission Owner: Vermont Transco |
| Southwest Connecticut | *Southwest Connecticut Reliability Project* – addition of 345 kV line to improve the transfer of electricity and system performance in Southwest Connecticut. Phase II: to include a 70-mile, 345 kV circuit from Middleton to Norwalk scheduled for completion in December 2009. Transmission Owner: Northeast Utilities, United Illuminating |
| **Planned Projects/Studies** | |
| Southern New England | *New England East-West Solution (NEEWS)* – consists of reinforcing the transmission lines at the intersection of three states (MA, CT, RI) and also within Greater Springfield, Rhode Island, Interstate and Central Connecticut. Project plans and costs expected to be finalized by the end of 2007. Application for siting approval expected for early 2008 with project completion in the 2011 to 2013 timeframe. Transmission Owner: National Grid, Northeast Utilities |
| Maine to New Hampshire | *Maine Power Reliability Program* – major study will identify alternatives to meet basic transmission reliability standards including a detailed assessment of Maine's bulk power transmission system using computer modeling to analyze the 345 kV and 115 kV system under many operating conditions. The study will be based on a ten year load forecast and is expected to be completed by late 2007. Transmission Owner: Central Maine Power |

## Economic & Environmental Value

In addition to enhancing system reliability, transmission infrastructure can lower consumer electricity prices, enhance environmental protection and increase competition by eliminating barriers to electricity trading across the region. Using two recently completed 345 kV projects as a proxy, this section highlights the potential economic and environmental value of new transmission infrastructure on a stand-alone basis and in comparison to possible demand and supply resource alternatives.

The proxy projects are the Phase I Southwest Connecticut Reliability Project described in Table 4 and the NSTAR 345 kV Transmission Reliability Project described in Table 5. These are compared to alternatives that were considered but rejected by ISO New England and regulators as being neither feasible nor practical.[30]

The first, investing in energy efficiency – including consumer energy efficiency and load management programs – while vital to the region, cannot produce the large-scale peak load reductions required to mitigate future potential transmission system overloads. In addition, efficiency programs do not provide the same benefits as transmission investments in terms of enhancing competition and providing access to remote or clean generation.

The second – constructing a new generator within the constrained areas – was considered infeasible because significant upgrading of the existing transmission infrastructure would be required to connect to and deliver its electricity from both the Boston and Southwest Connecticut areas. Furthermore, under the generation divestiture provisions of electric industry restructuring in Massachusetts and Connecticut, both NSTAR and Northeast Utilities can no longer own generation facilities. This means that the companies cannot construct new generation facilities as a planning tool in ensuring the reliability of the transmission system.

While these alternatives were found to be neither feasible nor practical, their benefits are compared herein to those of the transmission projects in order to provide perspective on the economic and environmental value of transmission. As shown in Figures 8 and 9, the benefits derived from the transmission projects significantly outweigh capital investment – because they reduce or eliminate congestion costs and the need for expensive RMR agreements. The payback, in a financial sense, is rapid. The projects also provide environmental benefits such as the reduction of greenhouse gas emissions and pollutants through the reduced operation or retirement of old and inefficient generating plants.

[30] Alternatives included in Schedule 12C Application Report for both projects.

## Table 4
## Phase I SW Connecticut Reliability Project

**Project Need**. Southwest Connecticut was the only major part of the state not connected to the 345 kV transmission system. The area was served by a system of 115 kV lines -- many installed more than 40 years ago -- which was never intended to support the electricity demand of the early 21st century. Despite numerous upgrades made over the last few decades, the system was simply not adequate to supply the areas continuing growth in electricity usage. During the five-year period preceding the company's application for siting the project, the peak load in the area increased by approximately 27 percent causing line overloads, voltage degradations and short-circuit currents and an increasingly elevated risk of outages.

**Description.** This Northeast Utilities (NU) project included construction of a 20.3 mile 345 kV transmission line between Plumtree Substation in Bethel and the Norwalk Substation in Norwalk, Connecticut (including 8.5 miles of new overhead construction and 11.8 miles of underground cables). The new 345 kV transmission circuit incorporated two different underground cable technologies. At the Plumtree Substation in Bethel, a state-of-the-art 345 kV outdoor gas-insulated substation was required because the space for expansion was constrained by adjacent wetlands. The project was announced in the summer of 2001. However, because of local opposition and siting complications, construction did not begin until March 2005 – almost a four year time frame. The project was energized October 12, 2006 (two months ahead of schedule).

**Cost:** $343 Million ($10 million under budget)

**Benefits:**

- *Electricity equivalent to one large generating plant:* The project increases electricity capacity available to the area by 600 MW (equivalent to one generating plant serving about 500,000 households a year) assuring reliable uninterrupted service particularly during peak usage.

- *Consumer savings of more than $100 million annually:* The project reduces existing federally-mandated transmission congestion charges (nearly $100 million annually) and contributes to the eventual mitigation of expensive reliability agreements with generators located in the area that total more than $200 million.

- *Environmental:* The new line connects consumers to new generating plants that use cleaner fuels and reduces the operation of older, inefficient, high-emitting facilities required for reliability purposes.

## Table 5
## NSTAR 345 kV Transmission Reliability Project

**Project Need.** The primary purpose of the project was to maintain reliability of the transmission system serving the City of Boston and surrounding communities. Without the project, load growth was projected to exceed available transmission capacity beginning in 2006, causing the area to experience potential overload conditions. In 2000, the electric grid serving the city was reinforced from the north by the installation of two 345 kV underground circuits, but the transmission lines serving key load centers from the south were limited to 115 kV circuits that were incapable of providing the level of capacity needed to serve consumer load.

**Description:** The project involved the construction of two underground circuits. The new circuits connect the existing 345 kV system located south of Boston (Stoughton/Canton border) with two key substations in the City of Boston. The 18-mile project was initiated at a new switching station in the town of Stoughton. One underground cable was installed to Hyde Park and the other line to South Boston K Street substation. The existing substations were enhanced to accommodate the new lines. Construction began in the spring of 2005. Line 1 was energized in October 2007; Line 2 in April 2007. At the time, it was one of the largest underground transmission infrastructure upgrades in the history of the U.S. utility industry. A third line is scheduled to be installed in 2008 (Phase II).

**Cost:** $220 Million

**Benefits:**

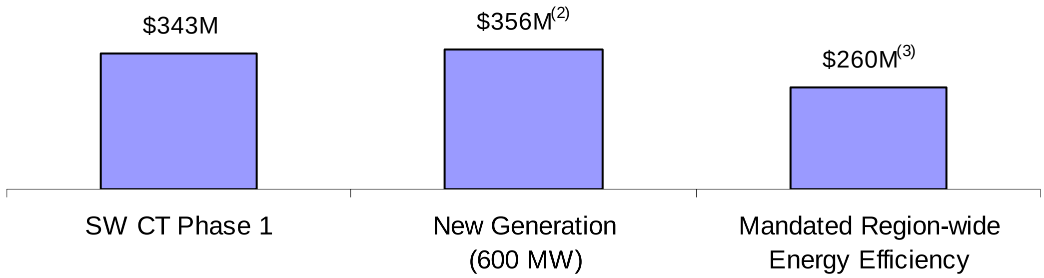
- *Electricity equivalent to two large generation plants:* The project provides the capability to import 1,000 MW of electricity to the greater Boston area (equivalent to serving about 800,000 households a year). Import capacity into the area is increased by approximately 28 percent.

- *Consumer savings of about $260 million annually:* The project eliminates $130 million/year in federally mandated transmission congestion costs; $30 million a year for a Reliability Agreement with New Boston Generation Station Unit 1 (now under deactivation because it is no longer needed); and contributes to the elimination of the Mystic Units 8 and 9 Reliability Agreement which were costing consumers $289 million annually (assumed NSTAR transmission project to contribute one-third of those savings).

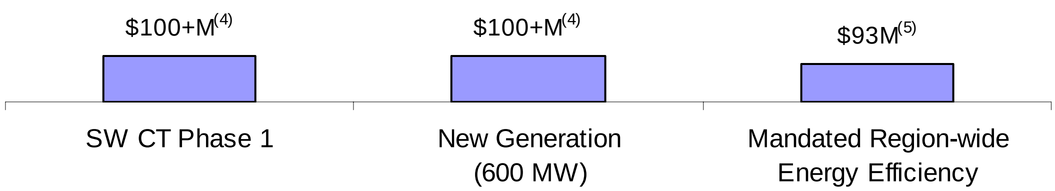
- *Environmental:* Through the deactivation of the New Boston Unit 1, about 245,000 tons of $CO_2$ are avoided each year (assuming the electricity is now supplied by a new, more efficient natural gas-fired unit).

**Figure 8 – The Value of SW CT Phase I Transmission Project Compared to Supply and Demand Resource Alternatives [1]**

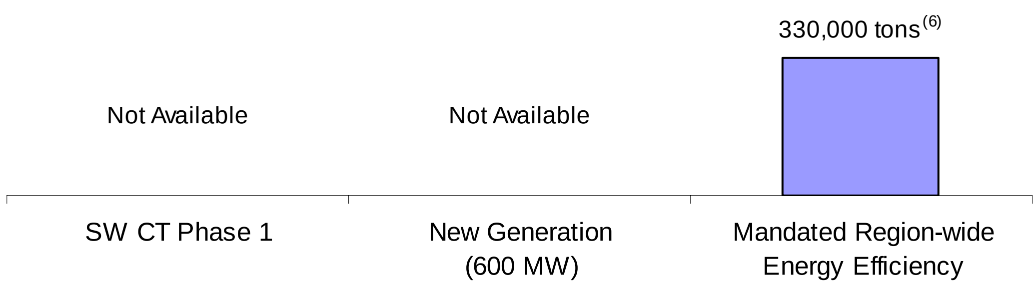
**<u>Cost</u> (one-time capital expenditure)**




**<u>Estimated Consumer Savings</u> (per year)**



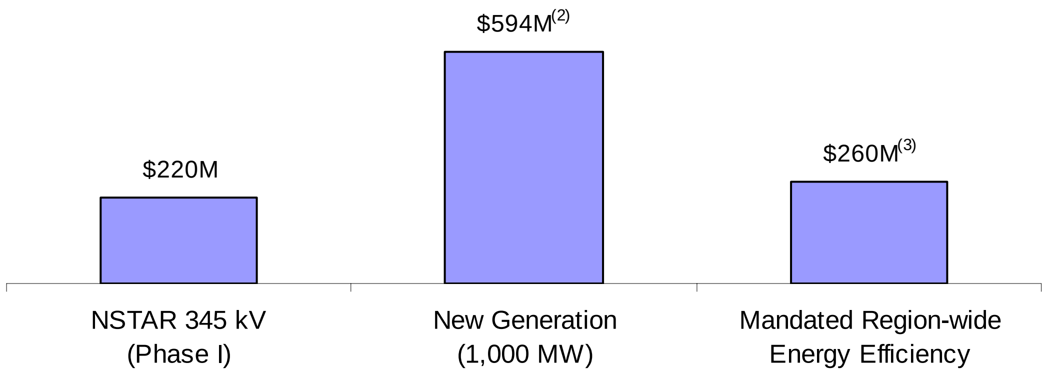

**<u>Estimated $CO_2$ Emission Savings</u> (per year)**



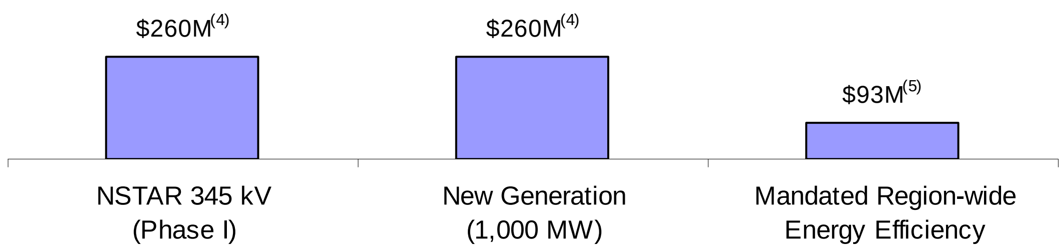

[1]While the alternatives were found to be neither feasible nor practical, the comparisons are made to put into perspective the value of transmission.
[2]Assumes cost of $594 per kW for a high-efficiency combined cycle of natural gas-fired generating facility (capital cost from U.S. DOE, EIA)
[3]Amount contributed by the region's consumers (mandated charge on electricity bill)
[4]Assumes $100 million per year savings in transmission congestion (estimated by Northeast Utilities). Potential future mitigation of RMRs would increase savings. New generation alternative assumed to provide similar economic benefits.
[5]Amount consumers currently save/year from consumer-funded energy efficiency programs (data from Northeast Energy Efficiency Partnership)
[6]Region's emissions savings from consumer-funded programs based on average fuel mix.

## Figure 9 – The Value of NSTAR 345kV Transmission Project Compared to Supply and Demand Resource Alternatives [1]

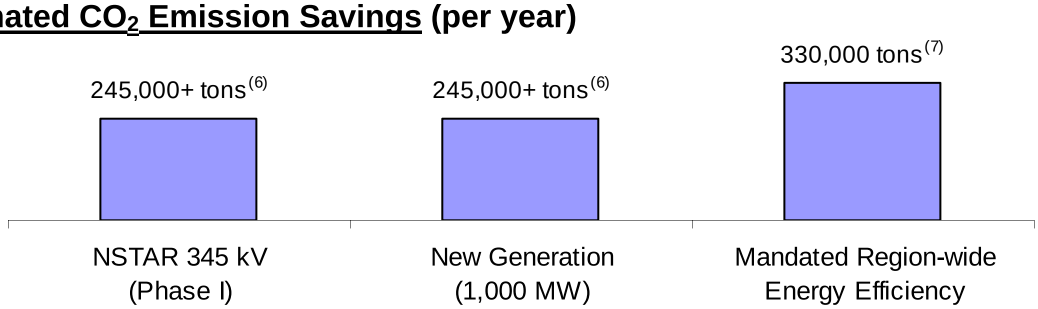
**<u>Cost</u> (one-time capital expenditure)**




**<u>Estimated Consumer Savings</u> (per year)**




**<u>Estimated $CO_2$ Emission Savings</u> (per year)**




[1]While the alternatives were found to be neither feasible nor practical, the comparisons are made to put into perspective the value of transmission.
[2]Assumes cost of $594 per kW for a high-efficiency combined cycle of natural gas-fired generating facility (capital cost from U.S. DOE, EIA)
[3]Amount contributed by the region's consumers (mandated charge on electricity bill)
[4]Assumes $130 million per year savings in transmission congestion (estimated by NSTAR); $30 million from elimination of RMR agreement for New Boston Unit 1 (being deactivated); partial contribution to elimination of RMR agreements on Mystic Units 8 and 9, totaling $289 million (assumed savings contribution of 1/3). New generation alternative assumed similar economic benefits.
[5]Amount consumers currently save/year from consumer-funded energy efficiency programs (data from Northeast Energy Efficiency Partnership)
[6]Amount of emissions savings from the closure of New Boston Unit 1 (assumed replacement with high efficiency natural gas-fired unit). New generation was assumed to have similar environmental benefits.
[7]Region's emissions savings from consumer-funded programs based on average fuel mix.

# V. Policy Considerations

The region must address the challenges of an aging transmission infrastructure, historic under-investment in infrastructure, complex siting processes and slow decision-making if the system is to remain robust and reliable *and* be the facilitator for an effective competitive marketplace.

There should be increased consideration from the perspective of market efficiency, which to be satisfied may go beyond reliability requirements. Beyond eliminating load pockets, bottled generation and RMR agreements, market efficiency is improved by the overall breadth and depth of the region's transmission system. The efficient ability to deliver the electricity commodity to the marketplace leads to decreased consumer prices and increased environmental protection.

On the basis of the previous sections, the following is a summary of key issues that should be addressed by state and federal policymakers going forward to assure that both reliability criteria and market efficiency requirements are met. The issues are listed in no particular order –- but to some extent are overlapping. No position is taken on these respective issues beyond the recognition that resolution – or at a minimum – consideration appears necessary.

## Transmission projects that provide economic benefits (not justified on the basis of reliability alone) face hurdles in demonstrating "need"

The transmission projects highlighted in Section IV show the significant economic benefits to consumers from new development – saving hundreds of millions of dollars every year in reduced congestion costs, decreased RMR agreements and the capacity to import lower-cost generation. These savings increase the economic competitiveness of the region, which is desirable given that New England has the highest electricity prices in the nation.

A recent national study of the benefits and costs of new transmission estimated that $12 billion of improvements to the nation's transmission system would yield net savings of $176 billion to consumers by 2030 due to reductions in congestion, operating reserve costs and economic impacts as the result of poor power quality and outages.[31] This study confirms the substantial consumer economic benefits associated with new transmission infrastructure.

New England has established a comprehensive transmission planning process with input from market participants, state regulators, and other stakeholders that evaluate transmission projects based on their impact on the region's power system and

[31] On a NPV basis, calculated by ICF Consulting in "The Costs and Benefits of Investing in the U.S. Transmission Grid", 2004.

consistency with industry standards. To date, however, the focus has been on reliability. No project has thus far has been constructed on the basis of economic or other benefits.

Planning processes should include other benefits of transmission infrastructure such as consumer economic savings, fuel diversity, emissions reduction, and decreased market power. Transmission capacity should be recognized as the infrastructure required to enable effective operation of competitive markets and compliance with environmental policies – and not for reliability purposes alone.

## Transmission planning policies do not account for fuel diversification or compliance with RGGI or RPS goals

New England's growing reliance on natural gas to fuel new generating plants has repeatedly raised concerns about declining fuel diversity of the region's electricity fuel mix. Natural gas is expected to soon fuel more than 50% of the region's generating capacity.

Fuel diversity is desirable as a hedge against potential natural gas supply disruptions, which could significantly effect the reliability of electricity delivery that the region's economy and quality of life depend on. Transmission planning policies should consider the expansion of infrastructure to increase access and accommodate more diverse electricity generation sources – such as renewables – that are often located in remote areas that otherwise makes interconnection expensive or uneconomic.

It must be emphasized that more renewable generation will also be necessary to meet the RGGI goal of reducing carbon dioxide emissions from electricity generation by 10% by 2019 – with the potential shutdown/retirement of existing fossil-fueled generating facilities.

In addition, most of the New England states have instituted Renewable Portfolio Standards (RPS) to ensure that a specified percentage of electricity is generated from qualified renewable sources.[32] However, the amount of renewable generation in the region remains limited – with a key constraint being lack of transmission infrastructure to remote locations (e.g. Northern New England) where wind generating facilities would most likely be sited. For instance, it has been estimated that more than 1,000 Megawatts of wind and other renewable generation sources could be developed in Maine, but the lack of transmission infrastructure could make individual projects uneconomic.

[32] MA renewable target level in 2006 is 2.5%, rising to 5% in 2010; CT's target level in 2005 is 2%, rising to 7% in 2010; ME is expanding its program; RI started its RPS program in 2007; VT utilities must meet all net demand growth with renewables; in NH, 25% of electricity must come from renewables by 2025.

Therefore, transmission must play a key role in increasing the amount of renewable generation in New England. However, while ISO's regional planning process includes consideration of project reliability and economic benefits, there is no evaluation classification for environmental upgrades.

One approach being taken in other regions is development of a "green" line dedicated to renewable generation development in areas with high renewable potential. For example, in California, the PUC, the ISO, and FERC have agreed on a "Tehachapi Policy" – which rate-bases a renewable "trunk line" ahead of the development of wind farms. Rather than incrementally building transmission to serve specific wind generating facilities, a transmission line is being constructed to serve an area with significant renewable potential. This "build and they will come" approach warrants some consideration in New England.

## Siting and approval of new transmission is lengthy and subject to local actions that can be detrimental to the region

A major obstacle of transmission infrastructure development has been significant delays during the siting and permitting process – particularly for large projects. An example is the application for the Phase I SW Connecticut Reliability Project which was submitted by Northeast Utilities in 2001.

In 2002, the Connecticut Legislature passed a law imposing a moratorium on new transmission development. In addition, the legislature established a working group to evaluate alternatives to the proposed transmission line even though ISO New England continued to identify southwest Connecticut as having the most serious reliability issues in the region. The Connecticut Siting Council (CSC) then requested NU to propose 21 different design variations involving a combination of underground and overhead lines. Not surprisingly, the outcome resulted in a more complex project than originally proposed. In September 2003, the CSC approved the final configuration, but Norwalk – one of the four municipalities impacted – filed an appeal that delayed the project until August 2004.

Such siting and process approval delays increase project costs and schedules and go beyond reasonable review and debate. The very nature of most transmission projects is that they traverse multiple municipal and state jurisdictions making siting a challenge even under the best circumstances.

## FERC-Approved Transmission Project Cost Allocation -- New England Stakeholders Continue Discussions

ISO New England has established a process – with stakeholder participation and FERC approval – to determine cost allocation for transmission projects.[33] Under the current methodology, two types of upgrades qualify as “Regional Benefit Upgrades” to receive cost recovery through regional rates.

To qualify, a project must be included in the ISO New England Regional System Plan as either a Reliability or Market Efficiency Upgrade. Essentially, these are enhancements or upgrades that are not related to the interconnection of a generator, but are necessary to ensure the continued reliability of the system, or are designed to reduce bulk power system costs to load system-wide.[34]

Once qualified, project costs are “regionalized” if they are determined to have region-wide benefits or “localized” if they provide only local benefits. This FERC-approved methodology was custom designed for New England’s tightly interconnected transmission system. It is administered by ISO New England and has been a key driver in the recent increase in transmission infrastructure development by providing financial certainty for new projects. However, the methodology continues to be discussed among some regional state regulators.

Currently, all New England states pay a portion of the costs of transmission upgrades built in the region regardless of which areas have caused the need for and which areas will primarily benefit from the upgrades (if they have been deemed to be needed for regional reliability purposes). Maine, in particular, is concerned about the costs to its consumers for transmission investments that will primarily benefit other parts of the region. The New England Conference of Public Utility Commissioners (NECPUC) resolved to conduct a study of alternatives to the FERC-approved transmission cost allocation methodology to determine whether refinements are needed to ensure the region’s methodology is equitable.[35] That study was completed and is undergoing review.

The issue is of concern in some states, as the total dollars for transmission projects are substantial. However, transmission is typically paid for over a 40-year period so the actual impact on a consumer’s monthly bill is relatively small as shown in Figure

[33] In recent years, FERC has also approved cost allocation methodologies for other regions including: New York, PJM, MISO, Southwest Power Pool and California. These cost allocation methodologies are in various stages of development. Comparison of these methodologies is complex in that each region possesses a unique set of physical characteristics, market dynamics and historical perspective that may have been taken into account during the development of respective cost allocation methodologies.

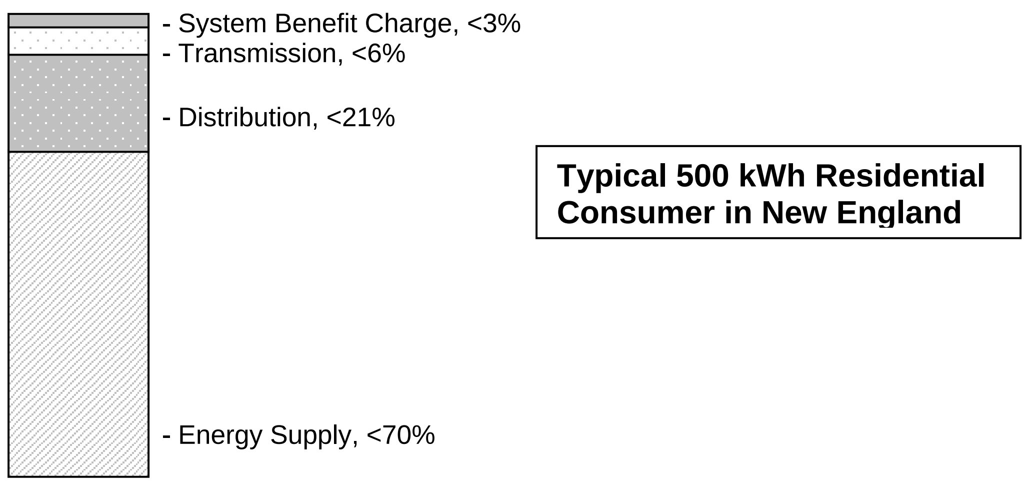
[34] To date, only two projects have been proposed as market efficiency transmission upgrades – they are in the conceptual stage – and no analyses has yet been done to determine cost allocation.

[35] NECPUC Resolution to Study Alternatives to the Current Transmission Cost Allocation Methodology, January 8, 2007. Resultant report: NECPUC Staff Report on Transmission Cost Allocation Pursuant to January 8, 2007 NECPUC Resolution, June 15, 2007.

10 below.  The value of being connected to a robust, reliable and highly efficient interconnected transmission grid, on the other hand, is significant.

While not all stakeholders are pleased with the region's transmission cost allocation methodology, it is an example of the importance of regional cooperation to address transmission issues.

**Figure 10 - Transmission Comprises a Small Component of a Consumer's Total Electric Bill**




Source: "Transmission Adequacy – The Path to Successful Markets", National Grid, Annual NECPUC Conference, June 25, 2007