A Background Report on Proposed Transmission Solutions for Southern New England

March, 2008

nationalgrid

Background Report Committee

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Foreword

National Grid is an owner and operator of transmission and distribution electric systems in Massachusetts, New Hampshire, and Rhode Island. The company is responsible for delivering power to all types of customers including residential, commercial, and industrial in areas of these states. National Grid has a legal responsibility to meet growing demand and to propose solutions that maintain reliable electric distribution and transmission service to all of its customers. The goal of this report and the public outreach is to inform and educate the public on National Grid's transmission investment plans.

This document has been prepared to provide an overview of electric energy issues in New England and related proposed transmission solutions for southern New England. The report was assembled by UtiliPoint International, Inc. (www.utilipoint.com), an independent consulting firm specializing in electric utility issues, at the request of National Grid. Volunteers, listed above, graciously agreed to serve on the "Background Report Committee" and were tasked with reviewing and critiquing the report content. We appreciate the input from the committee. The final content of the report is the responsibility of National Grid. National Grid is committed to providing an open and transparent discussion about electric power infrastructure issues. Your interest and input are encouraged and appreciated. We hope this document answers many of the questions you have.

Please direct any questions or comments you have to:

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1 Overview

Given electricity's vital role in our daily lives, utilities are responsible for building and maintaining highly reliable power systems. Even though it is invisible to most people, there is a complex, multi-layered system delivering electricity to the outlets on our walls. Power systems are one of the most complex systems in the world because the electricity generated must be in perfect balance with the electricity consumed (demand) at all times. Teams of system operators, computer models, and control systems are at work every minute of every day monitoring and managing the generation, transmission and distribution systems to ensure reliability, 24 hours a day, seven days a week, 365 days per year.

As explained in Section 2.0 of this report, power plants generate the electricity we consume and form the foundation of the power system. Connecting the electricity generated by these power plants to our communities are high-voltage transmission lines. The power plants and associated high-voltage transmission systems are designed to meet extremely high reliability standards because, if these parts of the power system fail, they can cause tens of thousands to hundreds of thousands of customers and large geographic areas to lose power.

New England's Growing Electric Demand

While our nation has one of the most reliable electric systems, there are many challenges to maintaining that reliability. In many regions of the country, increased electricity demand has led to investment in new generation and transmission infrastructure to maintain a reliable and reasonably priced electric supply.

Additionally the industry is experiencing rising and volatile fossil fuel prices and more stringent federal and state environmental regulations. These regulations require investments of billions of dollars to reduce the emissions of pollutants such as carbon dioxide, sulfur oxides and nitrogen oxides at existing power plants.

Section 3.0 of this report documents New England's growing electric demand challenges. Electric consumption varies second by second throughout the year, but from a utility planning perspective the "peak demand" (maximum consumption) in a year is a critical issue because the utility system must be designed to reliably serve this maximum demand. New England's peak demand has been growing and is projected to continue to grow for the foreseeable future. In fact, New England's peak electric demand in 2006 was nearly twice the peak demand of 1980.

Information found in Section 4.0 illustrates that the growth in New England's electric consumption would be even higher if it were not for energy efficiency investments by New England utilities in partnership with customers, state legislatures, and regulators. According to a report by the Independent System Operator of New England (ISO-NE), such programs have reduced electric demand by 1600 MW, which is nearly equivalent to the peak electric demand of the entire state of Rhode Island. Without these programs New England's peak demand would be about 6 percent higher than it is today.

National Grid is nationally recognized as a leader in the design and delivery of energy-efficiency, also called demand-side management (DSM), programs to its customers. In addition to efforts to curb the growth in electricity demand, the New England electric utility industry is making significant investments in infrastructure and other programs.

Transmission Investments

Growing electric demand requires substantial investments in the transmission system to maintain reliability as described in Section 5.0. Transmission lines are the superhighway delivery system of the utility industry. At some point, if there is too much traffic on the electric system highway, new roads must be built or additional lanes constructed. Not only do transmission bottlenecks cause reliability impacts, they can increase customer bills because it may be physically impossible to transport less expensive power from one area to another.

Where and how to invest in the transmission system requires thoughtful and coordinated study with other utilities in the region and ISO-NE. Studies are run to simulate power flows under a variety of conditions, including forecasting well into the future so that potential problems can be identified and addressed in advance of when they might actually occur. By systematically examining possible future operating scenarios, transmission planners identified the need to address several reliability concerns in the southern New England transmission system.

To address several of these regional transmission issues, National Grid must upgrade and add transmission facilities in Massachusetts and Rhode Island. The proposed solution represents hundreds of millions of dollars of investment in the transmission system. The proposed solution within National Grid's service area is divided into two distinct projects, called the "Interstate Reliability Project" and the "Rhode Island Reliability Project."

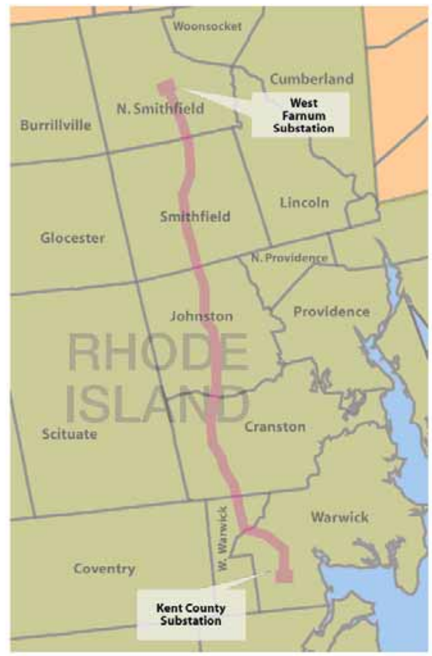
Interstate Reliability Project

Figure 1-1. The "Interstate Reliability Project."

This project involves adding a 345-kV transmission line to strengthen the ability to transfer electricity between Massachusetts, Rhode Island and Connecticut. The investment would also enhance the reliability of the high voltage transmission network serving the region. The new transmission line would be sited in an existing electric utility right of way, currently occupied by one or more transmission lines or structures. A right of way is the long strip of property on which a transmission line is built. The right of way may be owned by the utility or the utility may be granted an easement by a landowner to use the land.

Rhode Island Reliability Project

Figure 1-2. The "Rhode Island Reliability Project."



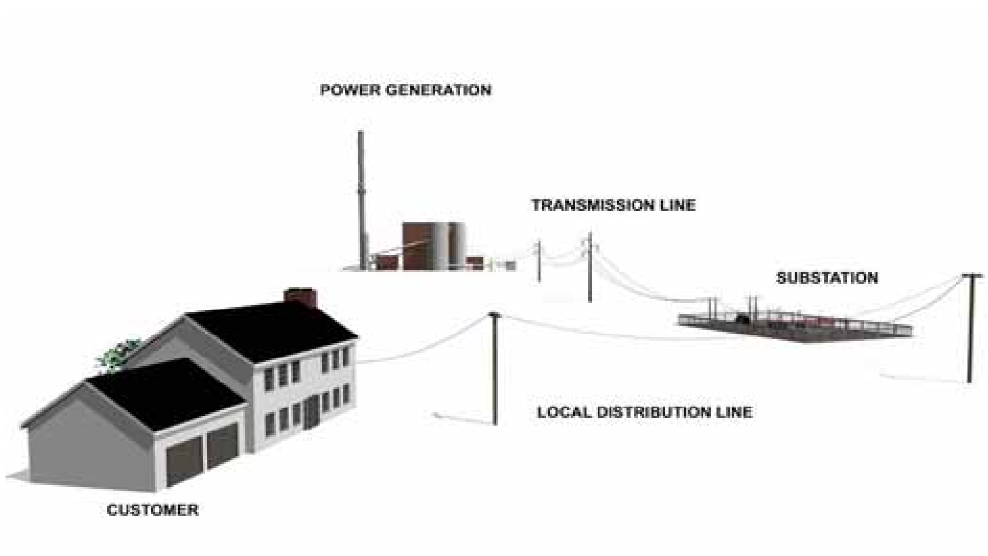
This project involves adding new 345-kV transmission line to strengthen the transmission system in Rhode Island. The investment would mitigate the possibilities of equipment overloads, voltage problems, power outages and the need to involuntarily shut off power to customers (known as "load shedding") in response to certain events (such as the loss of lines during lightning storms) that could occur.

Ultimately, National Grid has a legal responsibility to provide reliable electric service. It must plan and build for continued customer growth and propose cost-effective solutions that best meet the needs of its customers as well as comply with the various federal, state and local regulations. In 2008, National Grid plans to make the necessary regulatory filings required by law to implement the proposed solutions to address the reliability concerns that have been identified. Many of the federal, state and local permitting and licensing processes required for projects of this nature include opportunities for public involvement and input. If they projects are approved, construction is planned for 2010 to 2013.

2 Electric Utility Basics

Power systems are designed to reliably and safely move power from generation sources to customers. Although very complex in practice, conceptually the power system is divided into generation, transmission, and distribution as shown in Figure 2-1. Generation facilities (also known as power plants) convert an energy source such as natural gas, oil, coal, water, uranium or wind into useful electric energy. The generated electricity is transmitted to distribution substations at very high voltage levels (typically over 69,000 volts) via transmission lines. Transmission structures are tall and often constructed out of steel, but sometimes wooden structures are used. Utility transmission systems are normally interconnected with other utility transmission systems creating large regional transmission grids. Substations contain large transformers to convert from the high transmission voltage to the desired lower distribution voltage (typically under 35,000 volts).

Figure 2-1. Electric system components.



2.1 Generation

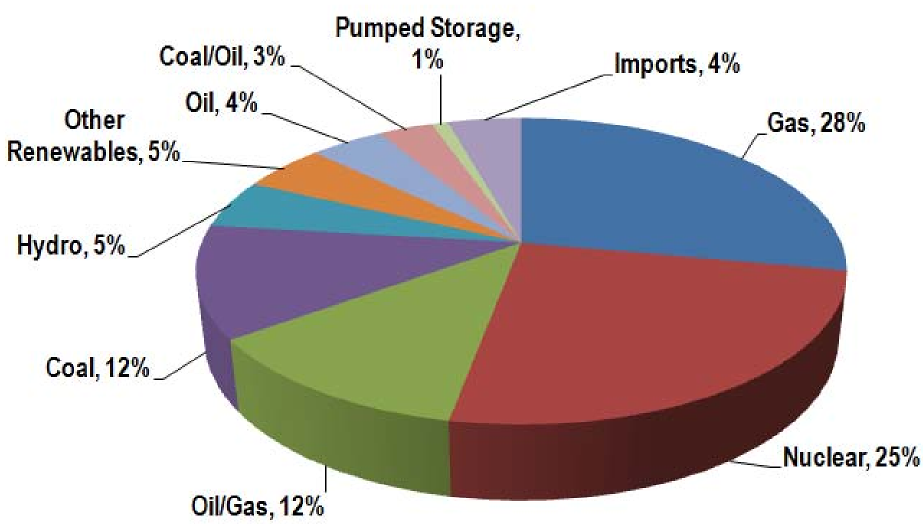
Power plants can be fueled by a variety of energy sources, most commonly in New England by coal, natural gas, oil and nuclear as is demonstrated in Figure2-2. About 4 percent of New England's electric supply is imported from Canada and surrounding regions. Renewable energy sources such as solar, wind and biomass are also becoming a factor as these technologies improve.

Figure 2-2. Power plant examples and New England power generation resources.

Brayton Pt.
Coal/Oil Plant
Somerset, MA

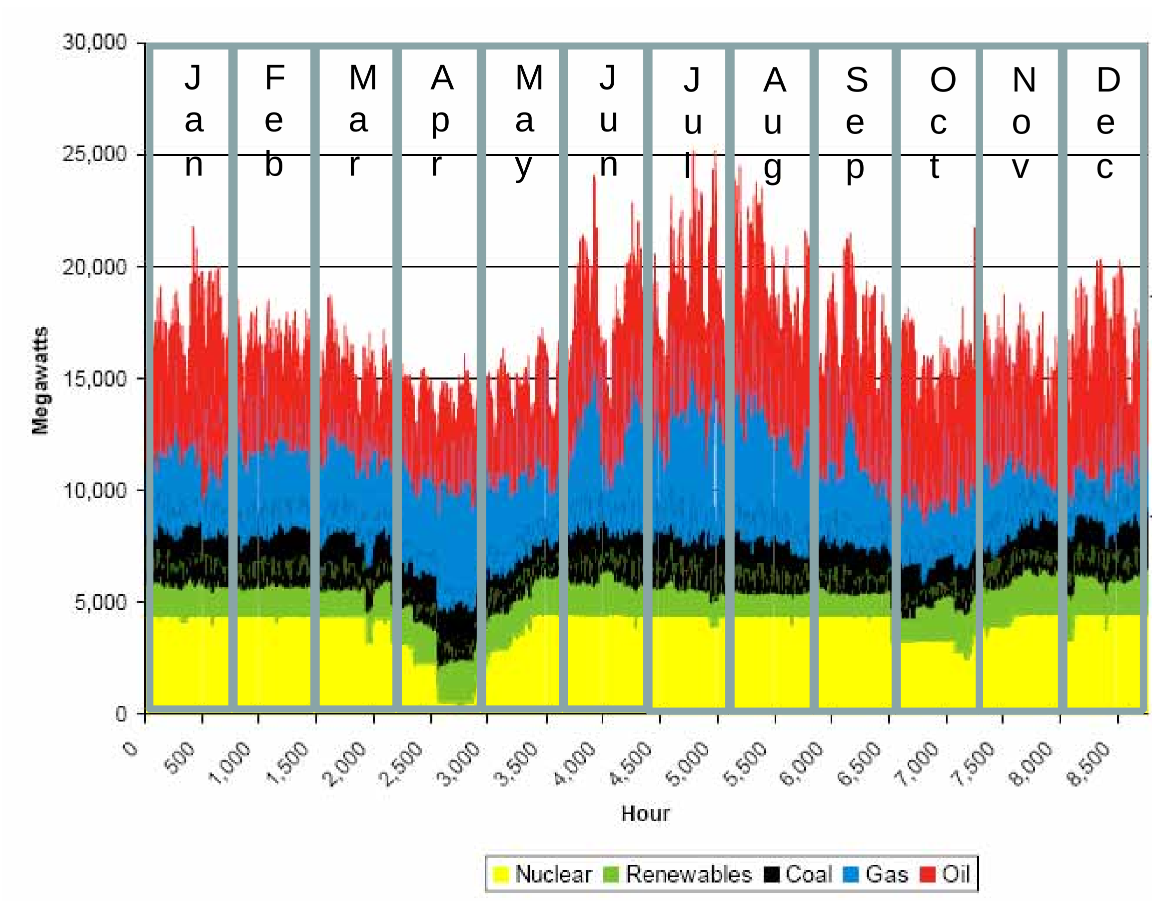
Pilgrim
Nuclear Plant
Plymouth, MA

Bear Swamp
Pumped Hydro
Rowe, MA



There are several reasons why New England utilizes a variety of generation types to meet the electricity demands of customers. Fuel diversity ensures the region is not overly dependent on one type of fuel source. Additionally certain power plants are better suited for certain type of applications. Nuclear and large size coal power plants are known as "baseload" facilities because they are generally designed to run around the clock in most days of the year and produce a large amount of electricity by typically operating at or near full capacity. But the electricity demanded by customers varies substantially throughout the day and seasons of the year. For example, in the summer, air conditioners may be off during the evening and on during daylight hours. Since the power generation supply must perfectly match electricity demand at every instant in time, there is a need for other types of generation plants to ensure a reliable supply. "Peakers," such as certain oil and natural gas fired generation facilities can be designed to start up relatively quickly and cycle to meet the peak demand. "Peakers" may only run during the 12 hours of a day when electricity demands are at their highest levels and then be shutdown overnight. "Intermediate" plants have characteristics somewhere between "peakers" and "baseload" facilities. They tend to be natural gas or oil power plants of modest size. They may run during weekdays, but turned off over weekends when electricity demands tend to be lower.

Figure 2-3. A combination of generation resources are needed to serve customers. Note the hourly, daily and seasonal variations in electricity demand during 2005.
(source: ISO New England Inc., 2005 New England Marginal Emission Rate Analysis)



Note: The yellow, green, black, blue, and red lines indicate the amount of power produced in a given hour of 2005 by nuclear, renewable, coal, natural gas, and oil power plants respectively.

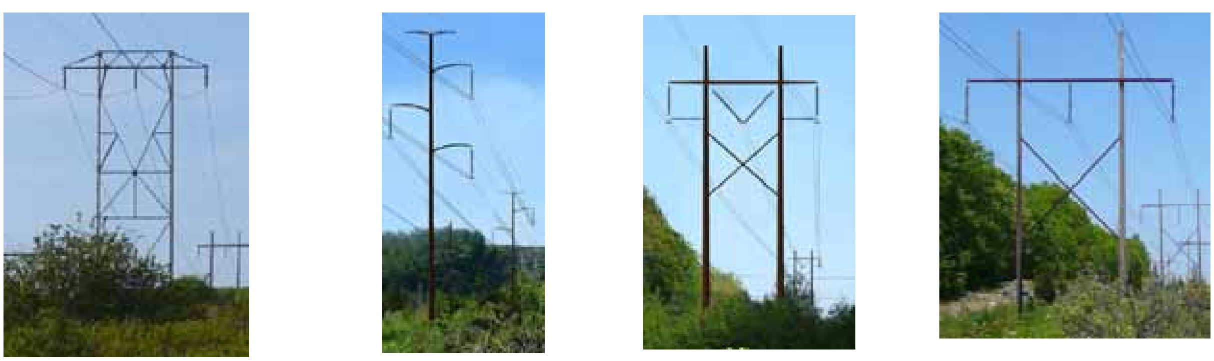
2.2 Transmission

Transmission lines may run tens to hundreds of miles and are used to bring large amounts of electricity from power plants to our communities. One key function of the transmission network is to ensure power is efficiently and reliably transferred from locations where it is produced to areas where it is consumed.

In New England these power lines operate at voltages ranging from 69,000 volts to 345,000 volts. Utility engineers use the letter “k” as shorthand for the word “thousand” and the letter “V” as shorthand for the word “volts.” So the term 345,000 volts is also commonly written as 345-kV, for example.

Transmission lines are carried on transmission structures, which come in many different designs. Transmission structures can also be made from different materials including wood and steel. The size of the transmission structure will depend on the operating voltage of the line, the type of material used, and the available width of the corridor it is constructed in.

Figure 2-4. Examples of transmission line structures.

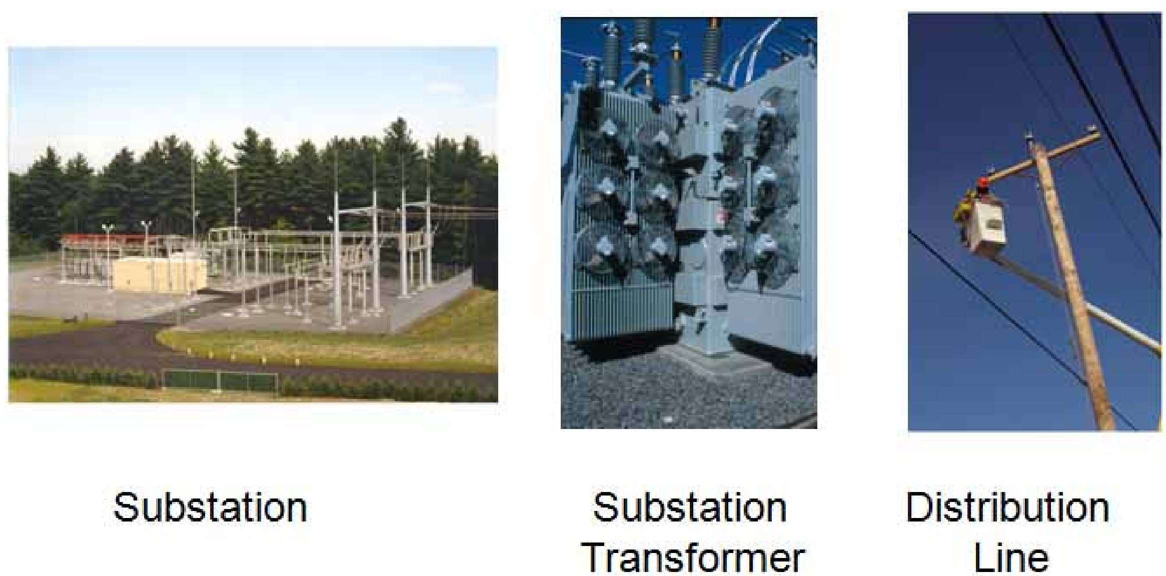


Steel Lattice Tower | Steel Monopole | Steel “H” Frame | Wood “H” Frame

2.3 Substation

Transmission lines deliver electricity to the distribution wires that serve communities through a facility known as a substation. Substation transformers convert electricity from transmission level voltages, such as 345,000 or 115,000 volts, to lower distribution voltages, such as 13,800 volts. Electricity is delivered to homes and businesses from the substation on distribution lines. Before entering our homes, the voltage is once again reduced to 120/220 volts using another transformer that is typically mounted on a distribution pole. These smaller distribution transformers are about the size of a large trash can.

Figure 2-5. Substation and distribution system.



2.4 Utility Measurements

The electric utility industry has several measurements it routinely uses to gauge various aspects of the power system:

- “Volts” (V) measure the power system “pressure.” Just like our blood pressure, the voltage in the power system must be kept within very narrow ranges or serious problems will result. Inadequate voltage will lead “brownouts” or in severe cases, “blackouts.” The shorthand for volts is the letter “V” and kV represents one thousand volts.

- “Watts” (W) measure the “flow rate” of electricity. For example, a 100-watt light bulb draws 100 watts of power when it is on. The shorthand for watts is the letter “W.”

- “Watt-Hour” (Wh) measures the amount of electric energy consumed over a period of time. If a 100-watt light bulb is left on for 10 hours, it will consume 100 watts times 10 hours of electricity, which is 1,000 watt-hours (Wh) of electricity. The shorthand for watt-hours is “Wh.”

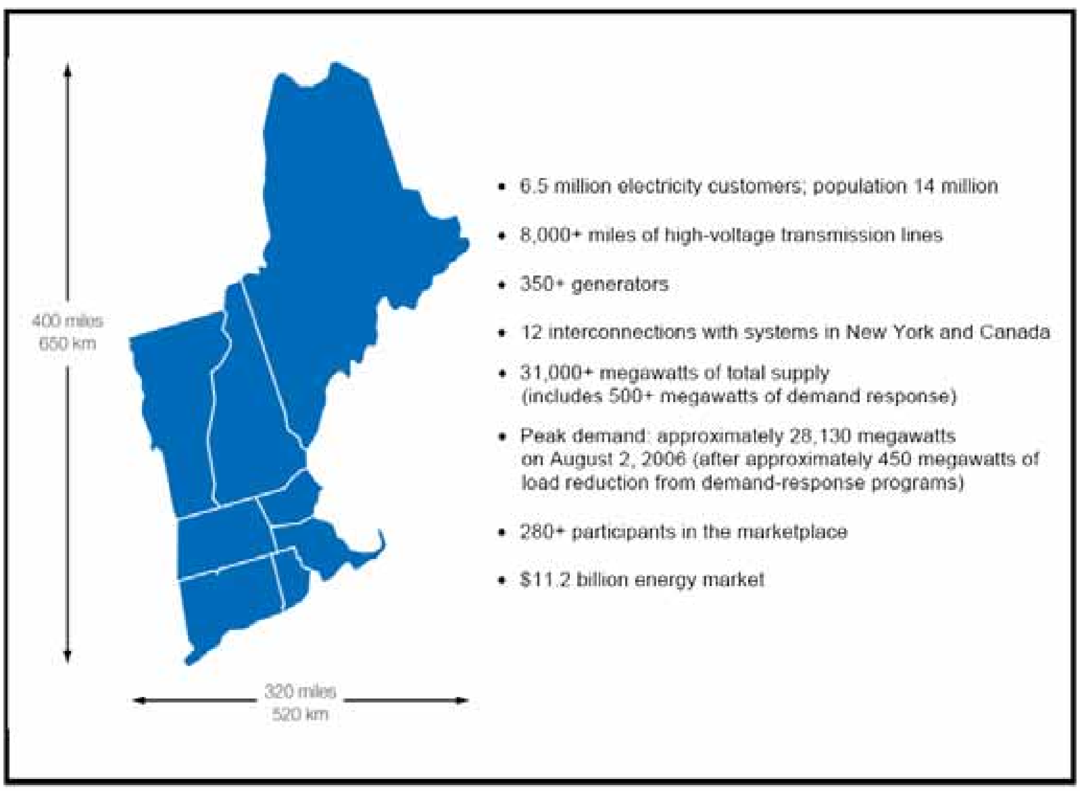
- “Kilo” (k) means one thousand and the letter “k” is used as the shorthand for one thousand. If a 100-watt light bulb is left on for 10 hours it would consume 1,000 watt-hours (1 kWh) of electricity. If electric rates are 15 cents per kWh, then leaving the 100-watt light bulb on for 10 hours would cost 15 cents.

- “Mega” (M) means one million and a megawatt is one million watts. The Brayton Point Power Plant, which is a very large power plant in Somerset Massachusetts, can produce up to 1,600 megawatts (MW) of electricity. The maximum (“peak”) electric demand in New England during 2006 was just over 28,000 MW.

2.5 New England Transmission System and Operations

Power systems have been called the most complex machines in the world because the electricity being made by power plants and delivered via the transmission and distribution wires must be in perfect balance with the electricity demanded by all customers at all times. System operators, computer models and control systems are at work during all hours of the year, monitoring and managing power plants and transmission systems to ensure reliability. In New England, National Grid owns and operates transmission systems in Massachusetts, New Hampshire, and Rhode Island. National Grid's transmission system is interconnected with other utility transmission systems across New England, Canada and New York.

Figure 2-6. Key facts about New England electricity (source: ISO-NE).



Note: "participants" include power generation owners, marketers, transmission owners, and other parties.

ISO New England Inc. (ISO-NE) is an independent, non-profit organization that plans and operates New England's bulk electric system, administers the wholesale electricity markets and oversees regional system planning. The ISO-NE is responsible for ensuring that individual utility companies plan for and operate the New England transmission system (also referred to as the transmission "grid") in a way that assures the reliability of the entire New England system.

ISO-NE reviews upgrades, modifications, and additions to the New England transmission system. If a transmission project is deemed to provide reliability or economic benefit to New England, ISO-NE will categorize the project as a Regional Benefit Upgrade and the cost of that project will be shared throughout the New England states using a funding mechanism called Pool Transmission Facilities ("PTF") funding. National Grid is expecting the transmission projects for Massachusetts and Rhode Island discussed in this report to be categorized as Regional Benefit Upgrades by ISO-NE. National Grid's Massachusetts and Rhode Island electricity customers pay approximately 16 percent and 6 percent respectively of all transmission related investments that are viewed by ISO-NE as Regional Benefit Upgrades.

Electric utility companies commonly interconnect with the transmission systems of other electric utility companies for reliability and economic reasons. Interconnections allow for more flexible sharing of generation resources. This sharing minimizes the amount of reserves and backup capacity needed to handle situations such as a planned shutdown of a power plant for maintenance or an unplanned shutdown resulting from an equipment failure.

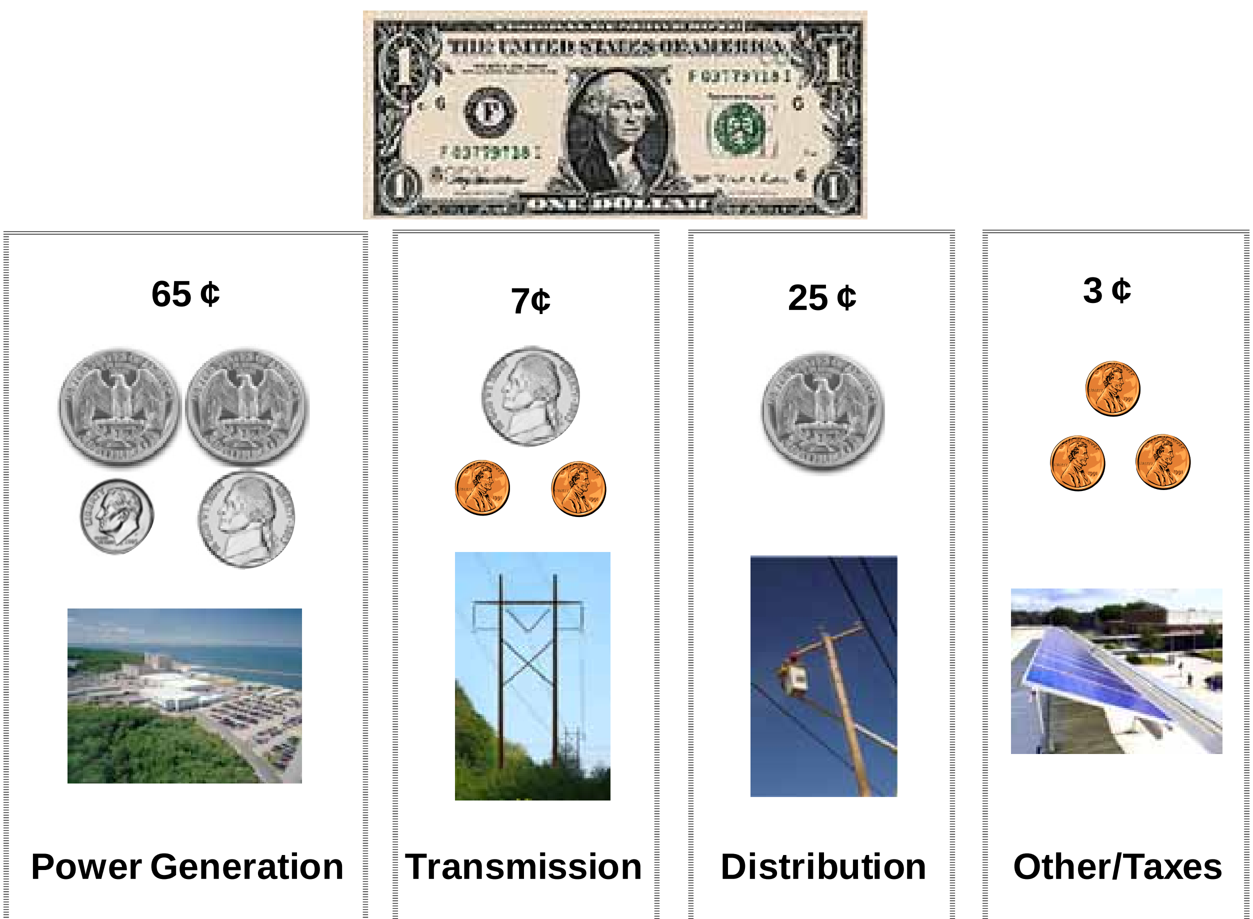
Generally utilities interconnect within logical geographic regions, also called "power pools" that are sufficiently large to achieve reliability and economy-of-scale benefits. Although these power pools may have interconnections (also known as "tie-lines") with other power pools, they often directly generate most of the electricity consumed within their region. Within the New England region, there is 33,350 MW of installed generation capacity. Interconnections to regions of New York and

Canada provide less than 5 percent of the total electricity used in the region but are an important source of power to help meet New England's electric needs. Without the interconnections with these two other regions, New England would have a need to build even more generation infrastructure or demand response capability.

2.6 Utility Economics

Typically around 65 cents of every dollar of an average electric bill goes to paying for power generation costs, including the cost of fuel. An individual power plant can cost hundreds of millions to billions of dollars to construct and cost tens to hundreds of millions of dollars a year to operate. Transmission typically makes up around 7 cents for every dollar on the utility bill, distribution about 25 cents, and other charges including renewable and energy-efficiency programs make up the remainder of a bill (3 cents).

Figure 2-7. What a dollar of the utility bill pays for (representative).



While electric transmission is a relatively small portion of the cost in the electric business, a new transmission project typically costs from tens to hundreds of millions of dollars. To minimize the impact on customer bills, the cost of utility investments are recovered from customers over a long period of time (typically 30 to 40 years). Homeowners do something similar when they buy a house and finance it over 30 years by taking out a mortgage.

By recovering investment costs in this way, even these large-scale transmission projects generally have only a modest impact on customer utility bills. Suppose there is a $400 million transmission project that qualifies for as a Regional Benefit Upgrade. In that case, approximately $64 million (16 percent) in project costs would be allocated to National Grid Massachusetts customers, while $24 million (6 percent) would be allocated to Rhode Island customers. These costs need to be collected, much like a bank collects a mortgage payment on a house. By spreading the “payments” over decades the impact on customer bills would be minimal.

The capital cost of a project is just one element in analyzing the overall economics of a utility project. Utility planners are tasked with developing the most cost effective solution, which includes not only the upfront investment (capital) costs but also accounts for benefit and cost impacts on other related operating expenses.

2.7 Key Planning and Operating Criteria

Transmission’s potential influence on the overall reliability of the power system is much larger than the 5 to 10 percent impact on a customer’s bill might suggest. If the transmission system fails, then large regions of the power system can experience a blackout. Achieving a high degree of reliability requires the system to have redundant features and excess capacity so that there is flexibility to reroute power due to equipment failures or when weather, accidents or other catastrophes cause a problem on the system.

Utility planners and operators commonly examine three types of scenarios when planning and managing the transmission system. For the first scenario, called "N-0," the transmission system must be capable of serving the electric demands under normal operating conditions. Electric systems contain thousands of pieces of critical equipment, such as transformers, that will occasionally fail. To provide another layer of protection, utility planners will look at adding backup systems to cover what are called "single contingency situations" like the ones just mentioned. These so-called single contingency scenarios are known as "N-1" (N minus one). The general philosophy is that no single piece of equipment failure on the power plant or in the transmission system will cause a large number of customers to lose power. Transmission designers further stress test the system design by looking at scenarios involving two or more equipment failures (known as "N-1-1" scenarios).

Utility planners in New England also apply two key criteria when examining the future needs for new power plants. First, that there only be one day in ten years when there would not be enough power supply available to meet the electric demand. Second, that there be 15 percent more generation capacity available than would be necessary to meet the forecasted peak demand on the system.

By using these and other criteria to plan and design the generation and transmission system, it is extremely rare that a customer loses power because of a problem in these parts of the system. Most customer outages are caused by a local problem on the distribution system such as a tree coming in contact with an overhead wire.

2.8 Transmission Design Considerations

The voltage level at which a transmission system is designed to operate greatly affects the amount of electricity that can flow over the transmission line. The higher the voltage, the more power the transmission system is capable of transmitting. For example, a 69-kV line may typically carry 100 MW of electricity, but a 345-kV line might carry over 1,000 MW of electricity.

In the water industry there is a similar principle. The higher the pressure (the equivalent of voltage) the more water will flow in a given pipe. But there are consequences to higher pressures. In the water business, the higher the pressure dictates that thicker pipe is needed to withstand the pressure. In the electric business, the higher the voltage, the taller the structures tend to be and the greater the need for insulation in electrical equipment, for safety purposes. All of the upgrades in height, spacing and protection have costs associated with them. Transmission designers need to carefully balance the added costs of higher voltage with the benefits of being able to carry more power. Similarly, the costs of maintaining backup systems and other means for building reserve capacity into the transmission system must be analyzed for the benefits these additional investments create.

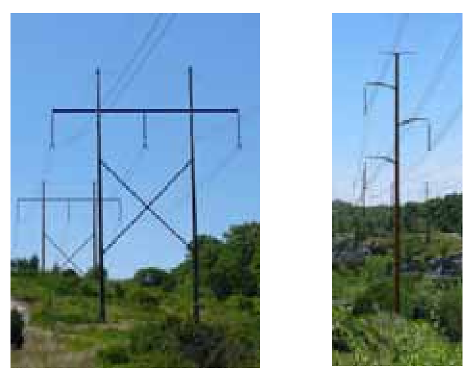
Utility engineers take into account numerous factors when physically designing a new transmission line. There are several design options available to minimize costs and impacts on the communities and environment. Construction costs, repair time and environmental impact, among other factors, generally lead to placing transmission lines place above ground (known as “overhead”) rather than underground. There are many types of structures that can be used to support overhead power lines. These structures differ in cost, span length (the distance between structures) and in height and width. In the end, the structure design must fit within the available corridor, minimize environmental impacts and be cost effective for customers.

2.8.1 Overhead and Underground Construction

Transmission lines are almost always built "overhead," meaning the wires are placed on tall poles or towers that typically are 60 to 100 feet or more in height. These structures can be made out of wood or steel. Steel structures , for example tend to come in two basic designs, a lattice type structure or "monopole" (a "single" pole). The selection of the structure type and material is driven by a number of factors including engineering considerations, costs, aesthetics, the voltage of the transmission line and the width of the available corridor where the line is to be constructed.

The photos in Figure 2-8 show an "H" frame and monopole design of transmission lines operating at the same voltage. Notice how the transmission towers have three major sets of lines on them. In addition to these wire "bundles", there are also less prominent "ground" wires that are normally located at the very top of the structure which are predominately used to provide protection from lightning.

Figure 2-8. Photos of a wood "H" frame and a steel "monopole" designs.



The lines are spaced so that air can act as insulation between them to prevent short circuits. In addition, a certain level of separation is necessary for worker safety and for providing sufficient clearance from trees and other vegetation.

There are many potential layouts of wires that affect both the width and height of the supporting transmission structure. One example of a configuration is a vertical design (the right photo in Figure 2-8) where the lines are essentially placed a safe distance above one another. The consequences of a vertical layout is that it normally will make the supporting transmission structure narrower but taller when compared, for example, to a layout where the wire bundles are laid out horizontally (the left photo in Figure 2-8). Wire bundles are sometimes laid out in a triangular manner which, in some sense, represents a compromise between the vertical and horizontal layout alternatives.

When engineers design a transmission system they may also consider rebuilding an existing line. For instance, suppose there is an existing 115,000 volt transmission line and a utility needs to build a new 345,000 volt line in the area. It may be possible to put both the 115,000 volt and 345,000 volt lines on the same structure. This is normally done by placing the lower voltage wire “bundles” a proper distance below the 345,000 volt wire “bundles.” Such a design is narrower when compared to building separate structures; however the tradeoff is a much taller structure. When using two separate structures the transmission tower height may be under 100 feet tall, but if put on the same structure the height could be over 150 feet tall. For reliability purposes, the consequence of putting two sets of transmission lines on the same structure can be negative. Anything that disturbs one line may cause a disturbance on both sets of lines, whereas if the lines were on separate structures only one line would be impacted.

Placing transmission lines underground might be beneficial from an aesthetics viewpoint. However, there are significant issues with underground transmission cables that normally limit their use to areas where there is no practical way to locate overhead lines, such as in the downtown area of a city.

One of the primary disadvantages of underground transmission lines is the significantly longer repair times when compared to overhead lines. While underground lines are protected from the direct impacts from trees and windstorms, they are still subject to failure for other reasons. When a failure occurs on an underground line, repairs typically take two weeks to more than a month while most overhead transmission line problems can be repaired within a day or two. The lengthy repair time for underground cables exposes the transmission system to potential emergency loadings and the risk of blackouts for a much longer period than overhead lines.

Underground transmission lines have several other operational issues that also must be considered when selecting a transmission system design. It is more difficult to have the same power rating from an underground line when compared to a single overhead line. The electrical nature of underground cables makes it more difficult to keep the system voltage within acceptable limits. Many “faults” (short circuits) or other problems on overhead lines are temporary in nature, and it is often possible to reenergize an overhead line after a short (several seconds) interruption. Faults on underground lines are almost never temporary, so the circuit must remain out of service until the cause can be located and repairs made. While some of these issues can be addressed by engineering controls, they add operating complexity and cost to the overall system.

Whether overhead or underground, the construction of a new transmission line is an expensive undertaking with underground transmission being particularly costly. For example, an overhead transmission line might cost $400 per foot to construct. An equivalent underground line may cost $1000 per foot to as much as $4000 per foot to construct or 2 ½ to 10 times as much as an overhead system.

Finally, there are environmental considerations associated with underground transmission lines. With overhead lines it is often possible to site the towers to avoid environmentally sensitive areas like wetlands, and span these areas to avoid directly impacting them. Underground transmission cables, by contrast, typically require trenching along the entire route, possibly creating environmental impacts in sensitive areas. While there are “trenchless technologies” available for underground lines, they have their own environmental and cost issues associated with them. If the underground lines are installed in established roadways, traffic disruptions and access to businesses and homes can be affected during the construction and maintenance of lines.

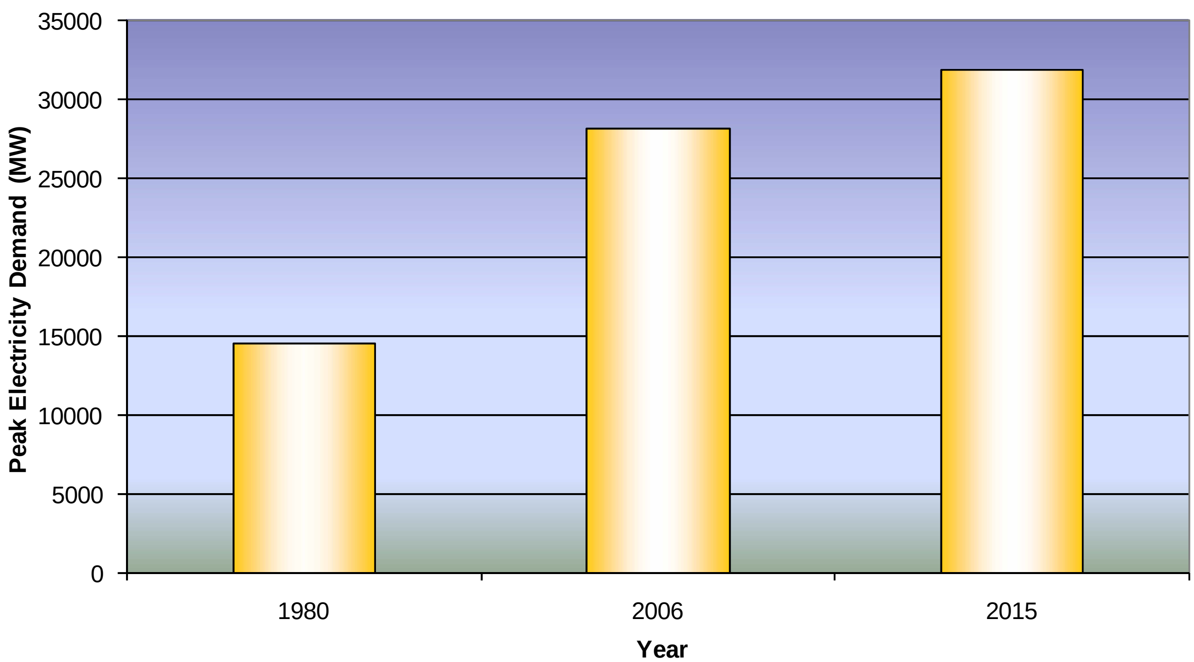
3 New England's Electricity Challenges

The electric industry in the United States is undergoing profound change and the New England region is no exception. There are several major issues confronting the industry as it plans for the future, including:

- **Carbon dioxide regulations** – Several countries and states have or are enacting limits on the total amount of carbon dioxide that may be emitted annually. Most analysts are expecting the United States to enact federal limits sometime in the next decade. These limits could financially disadvantage higher carbon emission plants such as coal compared to non-emitting sources such as nuclear or renewable energy resources.
- **Electric demand growth** – Electric demand is increasing not only because of population and economic growth but also because of other factors such as increased use of air conditioning and high consumption electric devices, including plasma TVs and large refrigerators.
- **Fossil fuel costs** – Fossil fuel costs are volatile and on the rise, especially natural gas. Prices have increased three to as much as ten times what they were in the low cost days of the 1990's.
- **New infrastructure investment** – With growth comes the need to expand the transmission system that transmits power from power plants to customers.
- **Renewable portfolio standards (RPS)** – Many states are enacting renewable portfolio requirements. These requirements typically mandate that a certain percentage of a utility's generation capacity be from renewable energy sources such as solar, wind and biomass. Massachusetts and Rhode Island both have enacted RPS requirements.
- **Investments must be prudent** – Utilities have the legal obligation to provide customers with reliable and cost effective electric service. Normally investments must be deemed as necessary, prudent and cost effective by state regulators before an investor owned utility (IOU) such as National Grid is allowed to recover costs from customers.

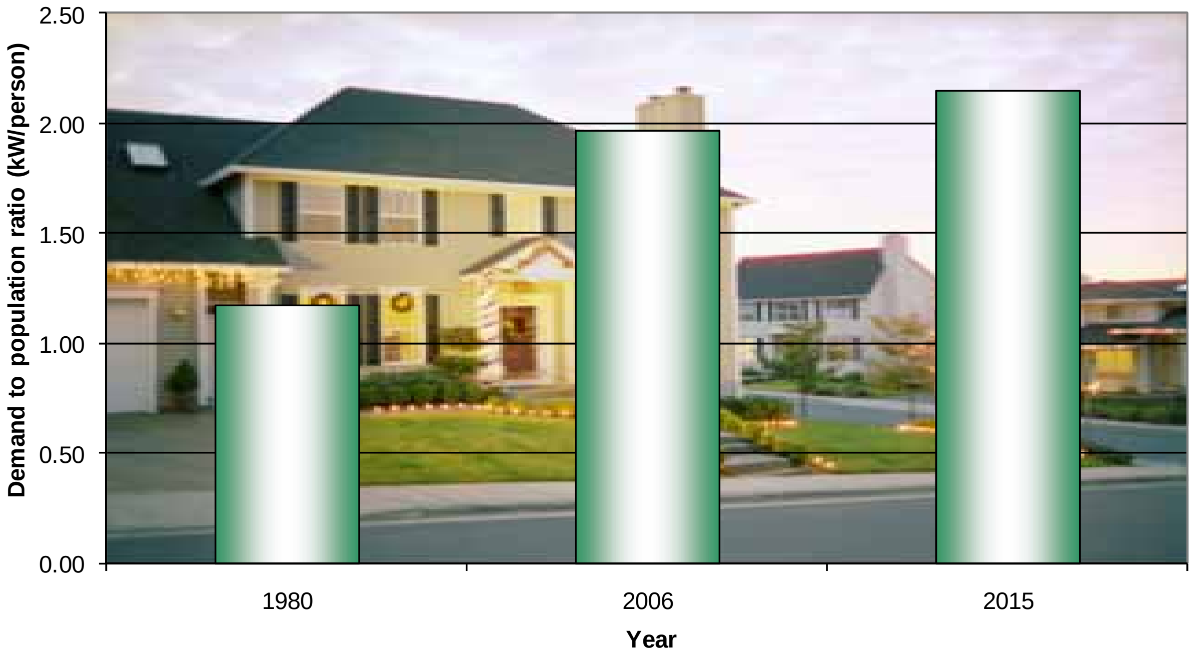
These and other factors impact the way utilities look at meeting growing customer demand. The power system must be designed to reliably and affordably serve the electric demand, especially the peak usage forecasted for current and future years. The demand for electricity at peak periods of usage has been growing in New England and is projected to continue to grow for the foreseeable future. In fact, the peak demand in 2006 was nearly twice the peak demand of 1980.

Figure 3-1. New England's peak electric consumption has nearly doubled since 1980 and is projected to grow to 32,000 to 34,000 MW by 2015 (source: ISO-NE).



Between 1980 and 2006 the population in New England increased from 14.5 million to 28.1 million and is expected to grow to nearly 32 million by 2015. As illustrated in Figure 3-2, by 2015 New England's peak electric demand per person is expected to be about 80 percent higher than what it was in 1980. This growth in peak demand per person is being driven by several factors such as economic growth and increased use of electric intensive appliances. As an example, in 1996 51 percent of Rhode Island households had air conditioners. A decade later, 83 percent of households have air conditioners.

Figure 3-2. The ratio of peak electricity demand to population is expected to rise from around 1.2 kW in 1980 to 2.2 kW in 2015, (data source ISO-NE).



Year	Peak Demand (kW)	Population	kW Demand per Person
1980	14,539,000	12,378,000	1.17
2006	28,127,000	14,269,000	1.97
2015	31,895,000	14,805,000	2.15
% change from 1980 to 2015			***83%***

4 Options for Meeting Electric Needs

Several types of investments working together are the key to meeting New England's electric needs. They include:

- reducing peak electric demand using energy conservation and demand response programs,
- increasing the use of renewable energy sources,
- investing in conventional generation such as gas-fired, and
- enhancing the transmission system to ensure the reliability and integrity of the power system as well as strengthening the development of renewable power such as wind generation.

4.1 Demand and Usage Reduction

Reducing electric demand, especially during peak periods of usage, and reducing total electric usage are areas of increasing focus for utilities. Power systems must be designed to handle the maximum consumption (called the "peak demand") by customers. By reducing the growth in peak demand, investments in new electric facilities such as power plants, transmission and distribution may be deferred.

Rising fossil fuel prices and more cost effective, state-of-the-art technologies are spurring customers to monitor and control their energy consumption, and considerable investments are being made to develop and implement demand reducing techniques. Utilities are responsible for educating customers about and implementing energy-efficiency and demand-side management programs that are cost-effective for customers. The types of demand-reduction programs are far ranging from directly controlling appliances to charging higher prices during times of peak electric demand to encourage customers to reduce electricity usage.

New England utilities supported by regulators and legislators already work to keep demand in check by making significant investments in energy reduction programs.

These programs are referred to as Demand-Side Management or "DSM" for short. According to ISO-NE, DSM and related programs are reducing New England's peak electricity demand by over 1,600 MW, which is nearly equivalent of the peak electric demand of the entire state of Rhode Island. Without these programs New England's peak demand would be about 6 percent higher than it is today.

National Grid is nationally recognized as a leader in the design and delivery of energy-efficiency, or demand-side management (DSM), programs to its customers. Over the last twenty years, National Grid's energy-efficiency programs have consistently helped participating customers significantly lower their energy bills by reducing their energy consumption. National Grid has also played a large role in the promotion of energy-efficiency standards in appliances and electrical equipment. The company is also a major contributor in the development of new standards that were recently adopted by the Commonwealth of Massachusetts to establish minimum green building requirements for all new state construction and major renovation projects.

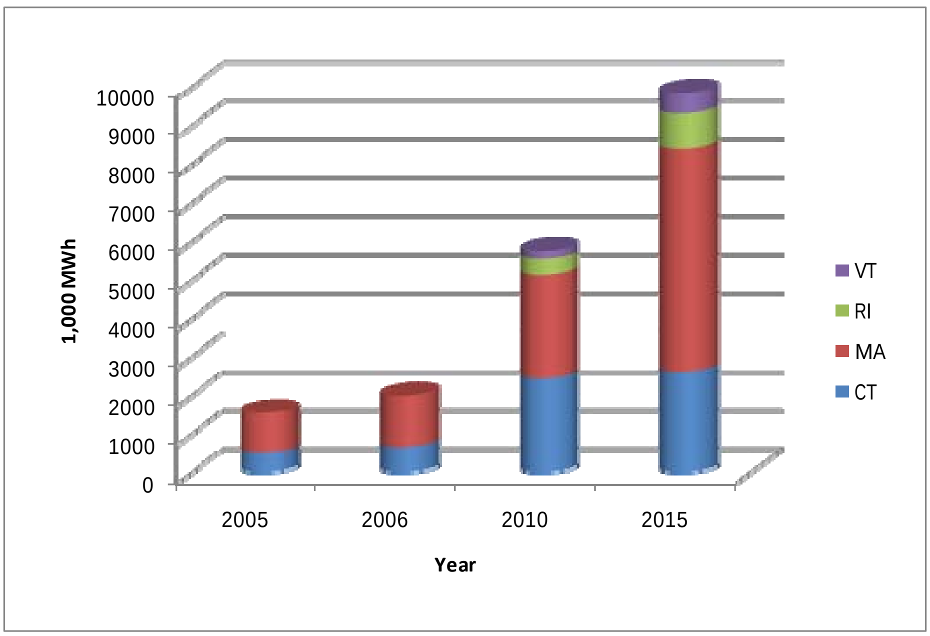
On an annual basis National Grid manages $69 million in energy-efficiency programs and in 2005 achieved a major milestone when its cumulative investment in energy-efficiency programs topped the $1 billion mark. During 2006, National Grid's award-winning energy-efficiency programs helped participating customers in Massachusetts, Rhode Island and New Hampshire save more than 265,550 megawatt hours of electricity – enough to power 32,400 homes for approximately one year. Reducing electricity consumption also saved more than 130,755 tons of carbon dioxide, the equivalent emission of 16,344 cars.

Demand reducing programs are expected to slow, but not entirely eliminate the growth in electricity demand. In fact, even with aggressive DSM the peak demand is expected to grow 4,000 MW or more over the 2006 to 2015 period. While cost-effective DSM programs slow the rate of demand growth, other investments must be made to meet the growth.

4.2 Renewable Energy Resources

Renewable energy resources such as wind, solar and biomass are seeing increased application for electric generation to help meet energy needs. Renewable Portfolio Standards (RPS's) provide incentives for developing these types of resources that emit no or low levels of pollutants. RPS's often require that a certain amount of generation supply come from such power sources. In New England, Connecticut, Maine, Massachusetts, Rhode Island and Vermont have adopted RPS's. The ISO-NE is projecting that by 2015 nearly 10 million MWh of electricity (an average of more than 1,000 MWh per hour), representing 6.5 percent of New England's electricity needs, will come from new renewable resources as a result of these New England state RPS requirements.

Figure 4-1. New England Renewable Portfolio Standards (source: ISO-NE).



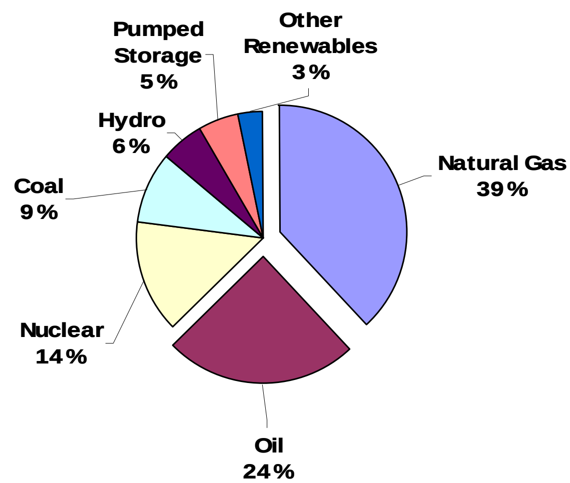
The various state RPS's are already stimulating investments. ISO-NE listed eighteen proposed large-scale renewable energy projects at year-end 2006. If all projects were constructed, they would represent 3.5 million MWh of annual electricity production capability which is the amount of electricity produced from a typical size coal generating unit.

Unlike baseload generation, which can operate around the clock, solar and wind are intermittent resources. For example, when a cloud passes over a solar generator, or the wind is not blowing, the power system must have other "backup" generating resources available. The transmission system must be capable of moving this "backup" electricity from where it is made to where it is needed.

4.3 Conventional Generation

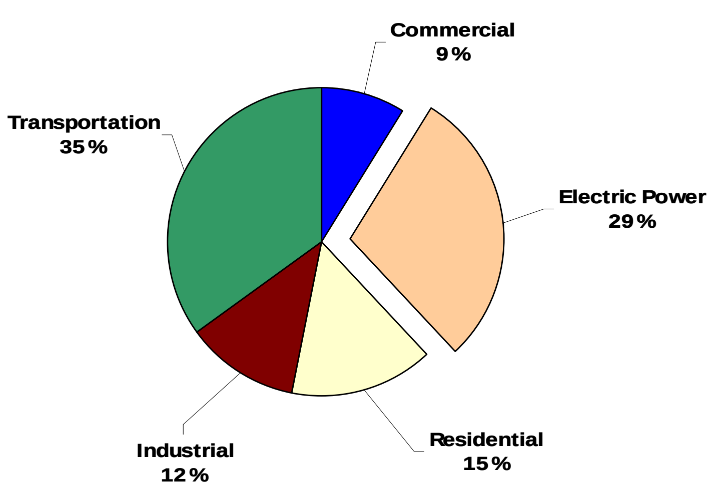
As explained above, conventional generating plants, such as those fueled by natural gas, coal, or uranium (nuclear), are able to generate large amounts of power and therefore serve a large portion of the New England electric needs today. One issue confronting New England and the nation has been its increasing reliance on natural gas generation. Since 1999, nearly 9,800 MW of new power plants have been constructed in New England, of which 9,500 MW were fueled by natural gas. Natural gas offers many advantages such as being the cleanest burning fossil fuel commercially available for electricity generation. In addition, natural gas plants are relatively inexpensive and can be constructed in what is a short amount of time compared to other types of power plants, typically two to three years. But New England imports nearly all of its natural gas via pipelines and a single liquefied natural gas (LNG) terminal in Everett, MA. This limited natural gas supply reduces the number of viable locations for new power plants. The limited supply also bring up other considerations such as supply disruption based on weather and other events. The growing dependency on and limited supply of natural gas makes its price much more volatile than other fuel sources with prices about three to ten times higher than the 1990's.

Figure 4-2. New England energy generation capacity by fuel type - 2006



Despite its drawbacks, natural gas power plants will likely be the type of "conventional" power plant constructed in New England for the foreseeable future. Electric power generation in the Northeast accounts for nearly 30 percent of all carbon dioxide (CO2) emissions in the region. Regulation of allowable CO2 emissions is proposed for the New England region. Most notably Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont are planning to participate in the "Regional Greenhouse Gas Initiative" (RGGI). The program aims to cap regional CO2 emissions from power plants at their current levels beginning in 2009 and ending in 2015. The states would then reduce the cap over four years to achieve a 10 percent reduction in power plant related CO2 emissions by 2019. This initiative may have a profound impact on the future of generation technologies deployed in New England. Energy conservation, renewable generation and nuclear generation may have an advantage because they have zero or near-zero carbon dioxide emissions. But nuclear plants can take well over a decade to permit and construct and their construction cost remains uncertain. Aggressive energy conservation and renewable energy programs are likely, but they may not be capable of meeting the CO2 targets alone. Coal, while a relatively inexpensive and plentiful fuel, can have double the CO2 emissions of natural gas power plants. Therefore, reducing the use of coal and oil generation and further increasing the use of natural gas electricity generation would be another way of producing net reductions in overall CO2 emissions in New England.

Figure 4-3. Northeast states 2003 CO2 emission by sector (source: State Energy Data System, Table 2, 2003 State Emissions by Sector).



Investment in new generation resources and/or demand growth ultimately leads to the need to upgrade or add to the transmission system. The following report section describes two such projects that are needed to improve and secure the reliability of the power system in southern New England.

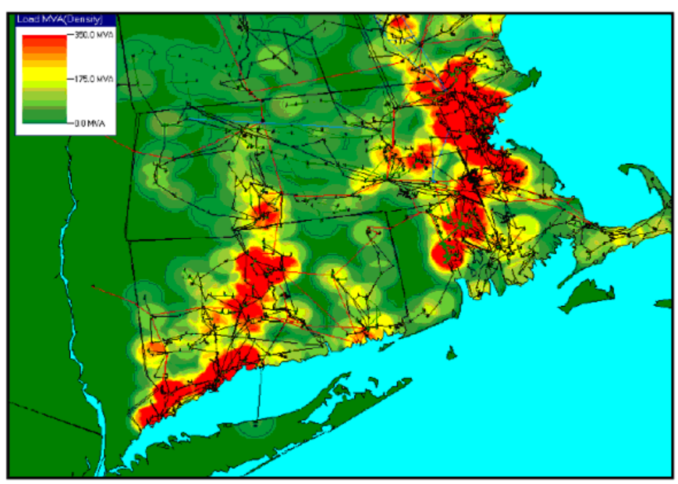
5 Proposed Transmission Projects for Southeastern Massachusetts and Rhode Island.

New transmission facilities, new power plants, energy conservation, and increased use of renewable energy sources are all part of the solution to the region's energy challenges. Transmission forms the backbone of the power system. As a result, "bottlenecks" in that part of system cause reliability concerns and can also increase customer electric bills because it may be physically impossible to transport less expensive power from one area to another.

In such a scenario more expensive, less efficient power plants can be required to generate power simply to support the demand in a local area because the transmission system is not capable of transmitting the electricity from elsewhere on the power system. For example, New England's transmission "congestion" cost about $180 million in 2006 because of the inefficiencies the congestion created by transmission limitations caused in the generation market.

The New England electric utility industry is responding to challenges of reliably serving the future electricity demand with significant investments in infrastructure and other programs. Five major 345-kV transmission projects have been sited in four New England states and are in various stages of construction and operation. From 2000 to year-end 2007, more than 200 transmission projects will have been put into

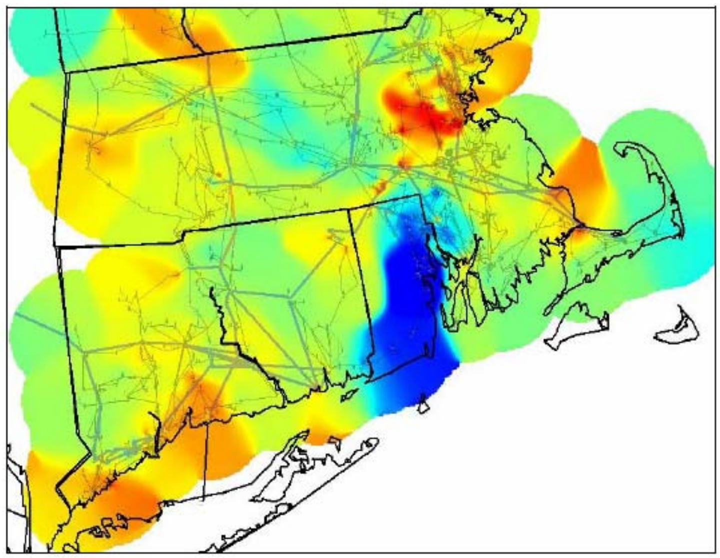
Figure 5-1. Electricity demand concentration in southern New England – red indicates area of high demand.



service representing an investment of approximately $1.5 billion.

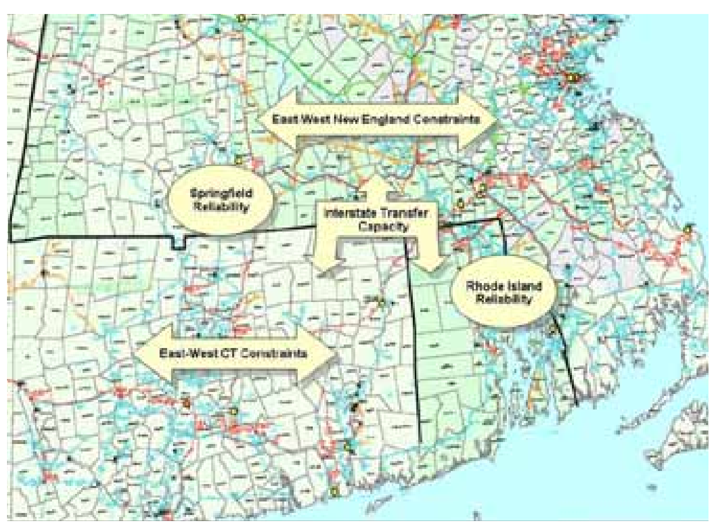
Where and how to invest in the transmission system requires thoughtful and coordinated study with other utilities in the region as well as ISO-NE. Studies are run to simulate power flows under a variety of conditions, including forecasting well into the future so that potential problems can be identified and addressed well in advance of when they might actually occur.

Figure 5-2. Example of a 2009 power system simulation result (low voltage conditions in blue).



The outcomes of these simulations allow engineers and planners to look at the possible consequences of unplanned events. For instance, the following graphic illustrates a 2009 scenario where the Rhode Island area would experience severe overloads and unacceptably low voltage (highlighted in dark blue) under certain "N-1" (the loss of one piece of equipment) conditions which could lead to customers losing power in the region.

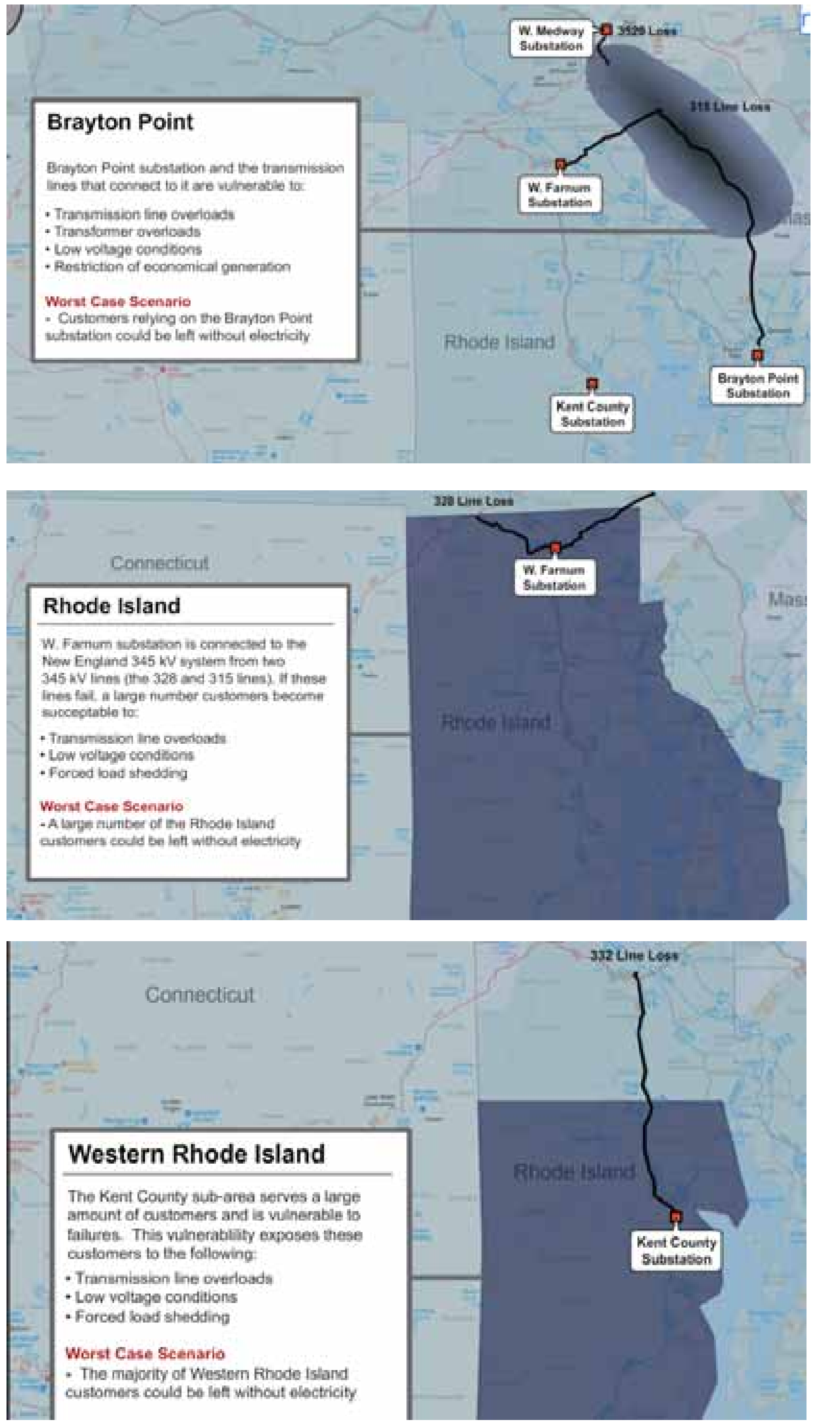
Figure 5-3. Electricity concerns in southern New England.



By systematically examining possible future operating scenarios, planners identified the need to address several reliability concerns in the southern New England transmission system. This study led by ISO-NE and supported by National Grid engineers and planners determined that different types of problems can occur in the New England region transmission grid depending on power system conditions, including:

- Constrained east-west power flows across New England;
- Overloaded facilities and voltage problems in the greater Rhode Island area because Rhode Island is overly dependent upon limited access to the area's 345-kV bulk transmission system;
- Overloaded facilities and voltage problems in the greater Springfield area;
- Limited interstate transfer capacity among Massachusetts, Rhode Island, and Connecticut affecting reliability;
- East-to-west power flows in Connecticut stressing the existing transmission system.

Figure 5-4. Examples of possible regional issues (areas potentially impacted shown in dark shading)



There are several specific examples, as well, as to how the reliability in southeastern Massachusetts and Rhode Island can be compromised if no transmission investment or upgrades are made in the area.

Take, for example, the situation in the Brayton Point area. Brayton Point, located in Somerset, Massachusetts, is New England's largest fossil fuel power plant and as a result plays an important part in regional power flows and reliability. Under a worst case scenario, with the loss of a transmission segment that connects to Brayton Point the region becomes vulnerable to a power outage. Similarly, Rhode Island may become vulnerable to an outage with the loss of one or more of the transmission lines providing power to key substations in the state such as West Farnum and Kent County.

Addressing these regional and local issues requires National Grid to upgrade and add transmission facilities in Massachusetts and Rhode Island. The proposed solution represents several hundreds of millions of dollars of investment in the transmission system. The solution within National Grid is divided into two projects, one called the "Interstate Reliability Project" and the other "Rhode Island Reliability Project."

5.1 The Interstate Reliability Project

For the Interstate Reliability Project, National Grid proposes to construct a new 345-kV transmission line to strengthen the ability to transfer electricity between Massachusetts, Rhode Island and Connecticut. This investment would enhance the reliable performance of the existing high voltage transmission network serving the region.

Figure 5-5. The Interstate Reliability Project.

The proposed line will begin in Millbury, Massachusetts and be constructed in the vicinity of Route 146, into North Smithfield, Rhode Island. It will then head west to Burrillville, Rhode Island and into Connecticut where it will connect with a neighboring utility, Northeast Utilities. The new transmission line would be sited in an existing electric utility right-of-way, which is currently occupied by one or more transmission lines. National Grid expects to finalize the engineering designs in early 2008. Applications for project approval will then be made with governing authorities and construction is targeted for 2010 to 2013.

National Grid expects using the existing right-of-way will minimize the cost, environmental and visual impacts of the project. Engineers have created simulated photos of the proposed transmission lines so that the public can get a sense of the types of transmission structures that might be used and the changes in view to the right of way that the public should expect. As the following examples in Figure 5-6 illustrate, in some cases new towers will be added to the right of way and in other cases existing towers will be replaced with newer types designed to handle the expected voltage, power flows, terrain and the wires they support.

Figure 5-6. Examples of proposed changes to existing right of way for Millbury, MA, Sutton, MA, N. Smithfield, RI and Burrillville, RI for the Interstate Reliability Project ("Before" on left, "After" on right.)


N. Smithfield - Millville MA Town Line Existing
View Facing North from Central Street


After
Visual Simulation Only


Burrillville RI
View Facing South from Collins Taft Road

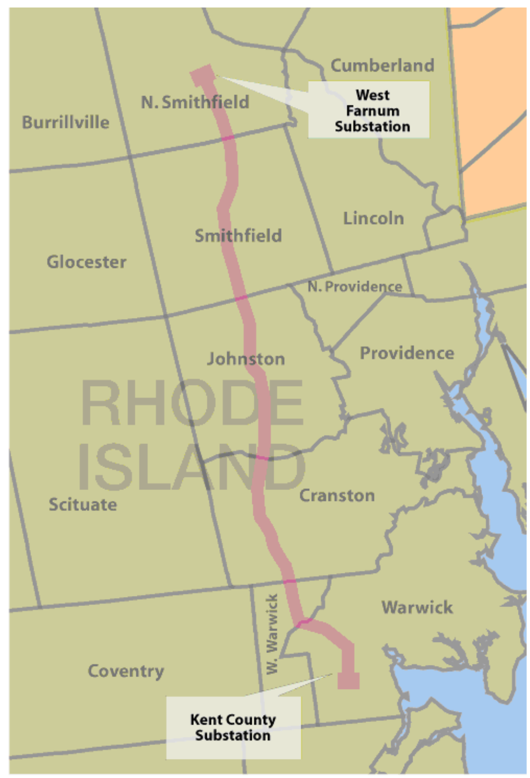

After
Visual simulation only

5.2 The Rhode Island Reliability Improvement Project

For the Rhode Island Reliability Project, National Grid proposes to construct a new 345-kV transmission line to strengthen the transmission system in Rhode Island. The new line would mitigate the possibilities of equipment overloads, voltage problems, power outages and the need to involuntarily shut off power to customers (known as "load shedding") in response to certain events that could occur.

The proposed line would connect the West Farnum and Kent County substations and would be located in an existing transmission right of way in the municipalities of North Smithfield, Smithfield, Johnston, Cranston, West Warwick and Warwick (Figure 5-7). The timeline for designing, permitting, and constructing this project is expected to coincide with the Interstate Reliability Project (2008 to 2013).

Figure 5-7. Rhode Island Reliability Improvement project.



As the following examples in Figure 5-8 illustrate, it is proposed that existing transmission structures (known as "H" frames) be replaced with a different design (known as "monopoles" because the wires are supported by a single pole).

Figure 5-8. Rhode Island Reliability Project right of way design examples for Smithfield, RI and Johnston, RI ("Before" on left, "After" on right.)

Note that two of the "H" frame style transmission towers would be replaced with "monopoles" to accommodate the addition of another transmission line (also of monopole design) in the existing right of way.

6 Electric and Magnetic Fields (EMFs)

Power lines, electrical wiring, electrical equipment and appliances all produce electric and magetic fields (EMFs). For more than 30 years, considerable scientific research and public discussion focused on the issue of EMF and health. Scientists around the world have conducted many research studies, and international and domestic government agencies, blue-ribbon scientific panels, independent health organizations and experts in both the regulatory and scientific communities have reviewed these studies to evaluate their potential implications for public health.

National Grid monitors and supports ongoing EMF research and tracks the conclusions of leading science and health organizations and government agencies around the world. The company's policy on EMF can be found at http://www.nationalgrid.com/emfs.

The company's EMF brochure, which includes links to information on internet sites of national and international scientific and health agencies, is included at the back of this document. Additional information and updates about EMF are available on the National Grid website, at www.emfs.info.

National Grid has personnel who are trained to measure EMF in customer locations and along our transmission and distribution lines. Property owners wishing to have EMF measurements taken should call National Grid's Ron Gillooly at (508) 389-4431 or email Ron at RONALD.GILLOOLY@us.ngrid.com

7 Corridor Selection Process

Finding a suitable corridor, or "path," for a new transmission line involves consideration of numerous factors. The process typically begins by taking the technical requirement for the project, such as the need to build a 345-kV transmission line from point A to point B and examining the possible corridors that can accommodate the line connecting those points. The utility gathers available ecological, physical, real estate and land use information from public and private sources. Various selection criteria are also identified for determining which possible corridors are potentially most favorable. Cost is part of the criteria but other factors such as potential impacts to environmental resources and existing land uses are also considered when evaluating a new corridor. Existing corridors occupied by transmission lines receive careful examination because building in existing corridors often involves less disturbance and fewer environmental impacts as oppose to creating a new corridor.

Figure 7-1. Aerial maps are examined for possible corridors.

Possible corridor segments that might meet the selection criteria are identified and then arranged in geographically continuous lengths and each viable corridor scenario is evaluated to identify viable corridor candidates. The goal is normally to narrow down the hundreds of possible segments to one to five possibly viable corridors. At the end of this stage of the selection process, one corridor may be labeled the "preferred" corridor and the other two to four candidates described as "alternates."

Once the possible corridors are identified and narrowed down, the utility may perform additional analysis and data gathering of the remaining candidate routes unless there is a clearly a superior option. Further studies may be carried out, such as inspection of wetlands and inventory of endangered species. A field review may also be conducted to gather additional information about the possible routes such as proximity to housing developments and the need for vegetation and tree management.

7.1 Corridor Selection for the "Interstate" and "Rhode Island" Projects

For the "Interstate" and "Rhode Island" projects, National Grid selected reconstructing existing rights of way as the preferred way to accommodate the proposed projects. National Grid's analysis indicates that using the existing rights of way is more cost-effective and has less impact on the environment and communities when compared to other alternatives.

Selecting a preferred plan required extensive analysis and research. National Grid identified a number of possible electrical solutions for each proposed project. Many combination of solutions were screened to identified system solutions that met the mandatory reliability criteria. Various route possibilities were compared using criteria such as environmental impact, "constructability" and cost.

8 The Project Approval Process

It takes years to study, plan and receive the necessary approvals to construct any major new electric facility in the states of Massachusetts and Rhode Island. Gaining the necessary approvals for a transmission project is generally a 2-year process. While the timelines for project approval may be similar in both Massachusetts and Rhode Island, their approval processes do differ. National Grid plans to submit the necessary approval applications in 2008 and expects to secure final authorization to move forward with the proposed projects in 2010. Construction would then begin and be completed by 2013.

Typically transmission projects require permits from federal, state and local authorities. The state approval process is described in this section. Before National Grid seeks state approval for a transmission project, the ISO-NE does a review of the project from a technical perspective to ensure it will be compatible with the overall New England system. Since ISO-NE is involved in the planning stages of National Grid's proposed projects it is likely the projects will pass technical review.

National Grid is committed to being a responsible member of the communities in which it operates. In addition to the public notices and public meetings required as part of the permitting process in Massachusetts and Rhode Island, National Grid has already begun its public outreach activities. These initial activities have included meetings with state and local officials, as well as distributing communications materials about the projects and holding meetings at homes of direct abutters along the rights-of-way in both Massachusetts and Rhode Island. Numerous other public outreach activities will take place throughout the planning, permitting, and construction process, including additional door-to-door outreach, municipal forums, public open houses, and advance construction notices. Throughout the entire process individuals, municipalities, businesses, and other stakeholders are invited to contact the National Grid community relations team to request a meeting to discuss any questions or concerns they may have.

8.1 Massachusetts

There are three major state agencies involved in securing authorization to move forward with a transmission project in Massachusetts, including:

- Massachusetts Environmental Policy Act Office (MEPA) - The MEPA office is part of the Executive Office of Energy and Environmental Affairs (EOEEA) providing environmental and regulatory review of transmission projects to make certain they comply with MEPA. After the application is filed, a notice is published in the state registry announcing the application. EOEEA will hold at least one public meeting and provide the public and other state agencies with the opportunity to provide comment on the project.
- Department of Public Utilities (DPU) - DPU ensures utility consumers are provided with the most reliable service at the lowest possible cost and oversees the energy facilities siting process. The DPU will host local hearings to allow for public input and will host evidentiary hearings to gather information and testimony concerning an infrastructure project. The DPU must find the project is in the public interest before the proposed project can move forward.
- Energy Facilities Siting Board (EFSB) – The EFSB is an independent state review board charged with ensuring a "reliable energy supply for the Commonwealth with a minimum impact on the environment at the lowest possible cost." Alternatives to a proposed facility, including one or more alternate routes (corridors) for transmission lines must be considered. As part of the EFSB approval process, public meetings are held in the locale affected by the project. The EFSB will also hold evidentiary hearings that may be combined with DPU evidentiary hearings.

The EFSB is required by statute to issue its order on the project within 12 months of receiving the application. The MEPA office and DPU do not have time limits on making decisions but generally are expected to provide their orders or approvals concerning a project within 12 to 18 months from receiving an application.

8.2 Rhode Island

The Rhode Island EFSB, consists of three (3) members: the Chairman of the Public Utilities Commission (PUC), the Director of the Department of Environmental Management (DEM) and the Associate Director of Administration for Planning. The Chairman of the PUC serves as the Chairman of the Energy Facility Siting Board. By state law, the Board is the licensing and permitting authority for all state and local licenses, which would be required for construction of a major energy facility in Rhode Island, except for licenses issued by the DEM under the delegated authority of federal law and under Chapter 2-1 of the Rhode Island General Laws, and licenses issued by the Coastal Resources Management Council.

After National Grid makes a filing with the Rhode Island EFSB, the EFSB will solicit input from many state and local agencies and the public on the project. Prior to public hearings held by state or local government agencies, National Grid will host public open houses and conduct outreach to landowners and other potential impacted parties. The PUC, for example, would provide input on the cost of and the need for the project. The DEM would provide its assessment of the potential environmental impacts of the proposed facilities. Town zoning boards and planning commissions will be asked for their input (called “Advisory Opinions”) on the project and may hold public hearings. The EFSB will also hold local hearings where the general public can express its opinion on the project. Finally, the EFSB will hold an evidentiary hearing on the project to solicit further input and testimony before making its final order. The process generally takes sixteen to eighteen months for a large transmission project.

9 Questions and Answers

In this section we try to anticipate questions that may have come to mind and provide clear answers.

Why are the transmission systems important to me?

Transmission delivers the power to our local communities from power plants located throughout the region and state. The transmission network is the backbone of the system and failures can cause large regional blackouts. To protect system reliability and prevent large-scale issues, utilities use multiple strategies to ensure the transmission system has high reliability.

If nothing is done, what will happen?

If the population and electric demand continue to grow as forecasted the reliability of electric service will be put in jeopardy. Because utilities are interconnected through transmission lines, one utility's failure to adequately plan for and design for serving its customers can impact others in the region.

Why are utility transmission systems interconnected?

Utilities interconnect because generally speaking it makes the power system more reliable and reduces the amount of power generation resources a utility needs to serve its customers. Through such interconnections utilities can rely on each other for backup power supply.

What can we conclude about electric and magnetic fields (EMF) and human health at this time?

Over the past 30 years, research has addressed the question of whether exposure to EMF might adversely affect human health. For most health outcomes, there is no evidence that EMF exposures have adverse effects. There is some statistical evidence from epidemiology studies that exposure to magnetic fields may be associated with childhood leukemia. Health agencies such as the World Health Organization have stated that this association is difficult to interpret because of limitations in the epidemiology studies, the absence of reproducible laboratory evidence, and a scientific explanation or mechanism that links magnetic fields with childhood leukemia. EMF exposures are complex and come from multiple sources in the home and workplace, in addition to power lines. The EMF health research remains a subject of debate and study. National Grid offers EMF measurements at no charge upon request and more information about EMF can be found at National Grid's web site: at www.emfs.info and in the brochure enclosed at the back of this report.

10 Glossary

Please note that ***bold italicized text*** refer to terms that are defined elsewhere in the Glossary.

Baseload – A baseload power plant is an electric generation plant that is expected to operate in most hours of the year.

Blackout – A total loss of power over an area; usually caused by the failure of major generating equipment or transmission facilities.

Brownout - Abnormally low voltage that causes voltage sensitive equipment such as computers, motors and certain types of lighting to have degraded or interrupted performance.

Conductor – A conductor is the part of a ***transmission*** or ***distribution*** line that actually carries the electricity, in other words, the wire itself. The wire or conductor is just one part of a transmission line; other parts include the poles and the insulators from which the conductor is hung. A conductor must have enough capacity to carry the highest ***demand*** that it will experience, or it could overheat and fail.

Contingency - A contingency is an unplanned event creating an outage of a critical system component such as a ***transmission*** line, ***transformer***, or ***generator***.

Demand - Demand is the amount of electricity being used at any given moment by a single customer, or by a group of customers. The *total* demand on a given system is the sum of all of the individual demands on that system occurring at the same moment. The *peak* demand is the highest demand occurring within a given span of time, usually a season or a year. The peak demand that a ***transmission*** or ***distribution*** system must carry sets the minimum requirement for its ***capacity*** (see also the definition for ***energy***).

Distribution - Distribution lines and distribution ***substations*** operate at lower ***voltage*** than the ***transmission*** systems that feed them. They carry electricity from the transmission system to local customers. When compared to transmission, distribution lines use shorter poles, have shorter wire spans between poles and are usually found alongside streets and roads, or buried beneath them. A typical distribution ***voltage*** would be 13.8-kV.

Easement – A right to use another's land for a specific purpose, such as to cross the land with transmission lines.

DSM (Demand-side Management) - Demand-side management, is intended to defer investments in generation or transmission facilities by curbing electrical ***demand*** growth. Energy conservation is one kind of DSM.

Fault - A fault is the failure of a line, ***transformer***, or other electrical component. Once such a component has failed (due to overheating, short-circuiting, physical breakage, or other trauma) it is automatically taken out of operation by a circuit breaker that quickly turns the component off. Once it has been "tripped off" it no longer poses a threat to human safety, but its loss may present a difficult burden to the remaining system (see also the definition of ***redundant*** below).

Generation or Generator - A mechanical generator is a device that converts mechanical ***power*** from an engine, a water wheel, a windmill, or other source, into electrical power.

kWh (kilowatt-hour) – A kilowatt hour is one thousand watt-hours. A watt-hour is a measure of the amount of electric energy generated or consumed in a given period of time.

kV (kilovolt) - A kilovolt is one thousand volts. Volts and kilovolts are measures of ***voltage***.

Load - see ***demand***.

Load Shedding – Intentionally turning off power to a customer or group of customers, usually for reliability reasons such as to avoid a blackout or equipment damage.

MW (Megawatt) - A megawatt is one million watts. Watts and megawatts are measures of power. To put this in perspective, the peak power demand for the New England region is approaching 30,000 MW or 30,000,000,000 (thirty billion) watts.

N-0 or **N-1** or **N-1-1 -** The term N minus zero (or one or two) refers to the failure of important equipment. Although these terms sound complex, they are actually quite simple. "N" is the total number of components that the system relies on to operate properly. The number subtracted from N is the number of components that fail in a given scenario. Therefore, N-0 means that no components have failed and the system is in a normal condition. N-1 means that only one component has failed. N-1-1 means that two components have failed, which is generally worse than having only one fail (see also the definition of ***contingency*** above).

Power - Power is the same thing as ***demand***.

PTF (Pool Transmission Facility) - Generally speaking, any transmission facility operating at 69 kV or higher and connected to other transmission lines or transmission systems is considered a PTF. PTF falls under the authority of ISO New England and the construction of new PTF facilities is funded through the ISO on a pro-rata basis among its member utilities.

Renewable power source - A renewable power source is any power source that does not rely on a *finite* fuel resource to keep it running, such as coal, oil, or natural gas, which will eventually run out. Renewable power sources include solar, wind and hydro generators, because sunlight, wind and running water will not run out. Generators that burn replaceable fuels also qualify as renewable power sources. Examples include bio-diesel generators that run on crop-derived fuels and wood-burning generators.

ROW (Right of way) - A right of way is the long strip of property on which a ***transmission*** line is built. It may be owned by the utility or it may be an ***easement***.

Substation - A substation is a fenced-in area where several ***transmission*** and/or ***distribution*** lines come together and are connected by various other equipment for purposes of switching, metering, or adjusting ***voltage*** by using ***transformers***.

Transformer – A transformer is a device that adjusts high-***voltage*** to a lower-voltage. Different voltages are used because higher voltages are better for *moving* power over a long distance, but lower voltages are better for *using* electricity in machinery and appliances. Transformers are commonly described by the two (or more) voltages that they connect, such as "115/13.8-kV," signifying a connection between 115-kV and 13.8-kV equipment or lines.

Transmission - Transmission lines and transmission ***substations*** operate at high ***voltage*** and carry large amounts of electricity from centralized ***generation*** plants to lower voltage ***distribution*** lines and substations that supply local areas. Transmission lines use poles or structures, have long wire spans between poles and usually traverse fairly straight paths across large distances. Typical transmission ***voltages*** include 345-kV, 115-kV and 69-kV.

Voltage - Voltage is much like water pressure in a system of pipes. If the pressure is too low, the pipes cannot carry enough water to satisfy the needs of those connected to them. If the voltage is too low, the electric system cannot carry enough electricity to satisfy the needs of those connected to it.