NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

BACKGROUND REPORT ON NEW HAMPSHIRE TRANSMISSION INFRASTRUCTURE

TO THE
NH GENERAL COURT

December 1, 2007

Pursuant to SB 140,
Laws of 2007, Chapter 364:1

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INTRODUCTION

In Senate Bill 140, which was signed into law by Governor Lynch on July 17 of this year,[1] the Legislature concluded that "it is in the public interest and to the benefit of New Hampshire to encourage the development of renewable energy" and that instrumental to such a goal the "existing transmission infrastructure, particularly in the northern part of the state, will need to be upgraded or replaced or new transmission facilities will need to be built." To assist it in its deliberations concerning how best to bring about the "[a]ppropriate upgrades to the transmission infrastructure…important to economic development," the Legislature directed the Public Utilities Commission to prepare a report describing:

1. the existing electricity transmission system in New Hampshire,
2. the current process for siting, constructing and financing transmission upgrades and expansion,
3. the approximate costs of potentially appropriate transmission upgrades,
4. approaches pursued by other states to encourage transmission expansion related to renewable generation, and
5. actions the Public Utilities Commission has taken to advance New Hampshire interests with respect to transmission.

This report, which is intended to lay the foundation for informed decision making by the Legislature, was prepared with the assistance and input of numerous stakeholders. Thomas Frantz, the Director of the PUC's Electric Division, and Michael Harrington, the PUC's Senior Policy Advisor for Regional Issues, held numerous meetings and facilitated discussions in Concord and the North Country with concerned citizens, developers of proposed renewable generation facilities, transmission companies, the Independent System Operator, and lawmakers.

Construction of transmission for remote renewables, or location-constrained resources, is currently an important topic in many parts of the country. In New Hampshire, the topic has been receiving increasing attention as a result of, among other things, Governor Lynch's call in August, 2006 for New Hampshire to "set a goal of ensuring that at least 25 percent of New Hampshire's energy comes from renewable sources by 2025" and the Legislature's subsequent passage in 2007 of House Bill 873, establishing minimum renewable portfolio standards for electric generation.

[1] The relevant portion of SB 140 is Chapter 354:1, Laws of 2007, effective 7/17/07.

Each state addressing the issue of how to incorporate remote renewables into the existing transmission network is responding to the circumstance that in most cases the areas where the wind blows strongly and consistently enough to support large scale wind farms are remote from the large population centers that can use the generation output; the same paradigm commonly applies to renewable technologies such as biomass where transporting the large volume of required fuel over long distances would be cost prohibitive. Transmitting power from remote facilities to population centers, furthermore, represents a realignment of the dominant approach to the generation, transmission and distribution of electric energy that has prevailed for over a century. Historically, most large generating stations were built close to population centers because it was the economically and technically rational decision. The transmission system was therefore constructed in such a way that the transmission lines diminished in size and carrying capacity as they moved further away from population centers. Consequently, transmitting power from remote areas where renewable generation is likely to be sited typically requires the upgrade of existing transmission or the construction of new transmission, as recognized in Senate Bill 140.

Upgrading or expanding transmission is further complicated, as observed by the Edison Electric Institute in September 2007, because "the optimal and most efficient transmission project can exceed the size needed to support the initial renewable generation development" and "the time required to plan, site, and construct the transmission to accommodate renewable generation distant from load centers will often exceed the time required to develop the initial renewable resource sites." Moreover, "[p]lanning new transmission infrastructure that only meets the needs of the initial development can limit future development and lead to costly upgrades to the newly constructed line." Finally, existing regulatory processes are not well suited to reconciling these timing mismatches, nor the competing needs of generation developers and transmission owners for financial certainty. The essence of the latter issue is that generation developers, before they make a substantial financial commitment, want to know how much they will need to pay for transmission, while transmission owners, before they make a substantial financial commitment, want to be assured that there will be sufficient generation to justify the additional transmission.

Section 1 of this report summarizes state and federal jurisdiction, describes the physical layout of the electric transmission system in New Hampshire and provides maps that depict the size, route and ownership of transmission lines. Section 2 includes a summary of the New Hampshire statute governing the siting of transmission lines, RSA Chapter 162-H, and a description of the process administered by the New England ISO, Inc. the Independent System Operator, for the construction of transmission lines. Section 3 provides high-level cost estimates prepared by Northeast Utilities, the parent company of Public Service Company of New Hampshire, and National Grid of several general transmission scenarios for integrating hundreds of MWs of new renewable generation in northern New Hampshire. Section 4 catalogues approaches being pursued in other states, most notably, Texas, California, Colorado and Idaho, seeking economic ways of financing the transmission needed to integrate remote renewable generation. Section 5 summarizes actions taken by the Public Utilities Commission regarding transmission. A conclusion is followed by a number of appendices providing supplemental information. The PUC website also has supplemental information and links: www.puc.nh.gov.

> *"Transmission investment and the allocation of the costs of those investments are complex issues, encompassing difficult modeling, environmental, economic, equity, and engineering questions."*[2]

1. New Hampshire's Existing Electricity Transmission System

1.1. Legal and Regulatory Decisions Affecting Transmission Policy

The financial well-being of virtually all aspects of our economy depends on the safe and reliable operation of the power grid, and a strong transmission network is essential to a well-functioning power market. The grid operates under a patchwork of federal and state laws and regulations. In order to better understand current issues surrounding transmission in New Hampshire and New England, it is useful to review the major legislation that has shaped the existing transmission system, a system that is still changing in light of the restructuring of the electric industry and mandates to increase the grid's reliability while encouraging the growth of renewable generation.

Until the recent development of independent system operators (ISO) or regional transmission organizations (RTO) in parts of the United States, such as New York, New England

[2] *A National Perspective on Allocating the Costs of New Transmission Investment: Practice and Principles,* A White Paper prepared by The Blue Ribbon Panel on Cost Allocation for WIRES, the Working Group for Investment in Reliable and Economic Electric Systems, September 2007, available at: http://www.wiresgroup.com/resources/industry_reports/Blue%20Ribbon%20Panel%20-%20Final%20Report.pdf.

and the Middle Atlantic region, the planning and construction of transmission was done by vertically integrated utilities under rate-of-return regulation. Retail prices were based on an individual utility's cost-of-service or revenue requirement.[3]

In 1935, Congress passed the Federal Power Act, significantly expanding the authority of the Federal Power Commission (FPC) over the nation's electric utilities, to include the transmission of electricity in interstate commerce as well as any wholesale power transactions. The Federal Power Act states under Title 16, Ch. 12, Subchapter II, Section 824. Declaration of policy; application of subchapter that:

> It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that the Federal regulation of matters relating to generation to the extent provided in this subchapter and subchapter III of this chapter and of that part of such business which consists of the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.

The Federal Power Act preserved states' jurisdiction over retail electric rates for local distribution and generation facilities. The FPC, which later became the Federal Energy Regulatory Commission (FERC), was granted clear authority over transmission service and electric sales at the wholesale level. In fact, Section 201(b)(1) is clear on this point. It states:

> (1) The provisions of this subchapter shall apply to the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce, but except as provided in paragraph (2) shall not apply to any other sale of electric energy or deprive a State or State commission of its lawful authority now exercised over the exportation of hydroelectric energy which is transmitted across a State line. The Commission [FERC] shall have jurisdiction over all facilities for such transmission or sale of electric energy, but shall not have …jurisdiction … over facilities used for generation of electric energy or over facilities used in local distribution or only for the transmission of electric energy in intrastate commerce, or over facilities for the transmission of electric energy consumed wholly by the transmitter." 16 U.S.C. Section 824(b)(1)[4]

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[3] Simply put, a utility's revenue requirement includes the costs it has prudently incurred to provide transmission, distribution and generation service. The revenue requirement equals the operation and maintenance costs of distribution, transmission and generation plus depreciation of those distribution, transmission and generation assets plus a commission-approved return on the utility's undepreciated capital investment plus income, business and property taxes.

New Hampshire's regulated utilities continue to have their distribution rates set under rate-of-return regulation though the generation rates, now known as default service rates, are procured through a competitive wholesale auction for those customers that choose not to purchase from a competitive retail supplier. Public Service Company of New Hampshire's retail rates also include cost-of-service ratemaking for its generation and purchased power component.

[4] The U.S. Supreme Court most recently addressed the extent of FERC jurisdiction over transmission in New York v. FERC, 535 US 1 (2002). For purposes of the upgrade of transmission in northern New Hampshire, it is reasonable to assume that any upgrades to the Coos County loop will be subject to FERC jurisdiction.

More recently, the electric utility industry has evolved, in various parts of the country, from a highly regulated, monopolistic industry with traditionally structured, vertically integrated electric utilities to a less regulated, competitive industry. The first significant provision for competition in electric generation came with passage of the Energy Policy Act of 1978. Included in the Energy Policy Act was a title promoting non-utility generation from renewable energy, The Public Utilities Regulatory Policy Act or PURPA. PURPA was enacted in response to the oil embargoes by the Organization for Oil Producing and Exporting Countries (OPEC) in the 1970s. PURPA's effects were mixed: some parts of the country saw little activity while others, such as the northeast and California, experienced significant renewable energy activity. For those areas, the new generators (known as Qualifying Facilities or QFs) also affected the planning and construction of transmission facilities in order to interconnect them to the grid. Unlike the large central power plants that were built by the utilities, the generating capacity from QFs was small and they were located, generally, at remote locations.[5] PURPA required utilities to purchase the output from QFs at the utility's avoided cost.

While PURPA set the stage for wholesale competition and non-discriminatory open access to transmission, the Energy Policy Act of 1992 promoted wholesale competition by removing some constraints on ownership of electric generation facilities and permitting any electric utility to ask the FERC to require another electric utility to provide transmission services (wheeling). Thus, the Energy Policy Act significantly increased competition by permitting generation owners to sell power at wholesale to non-contiguous utilities.

Transmission rates were set to promote the economically efficient development of generation and transmission. In 1995, FERC issued a Transmission Pricing Policy Statement, asserting that transmission pricing should encourage the efficient location of new generators, take place at the regional level and provide for the orderly and economic expansion of the transmission system. FERC soon issued two major orders, Orders 888 and 889, establishing the framework for today's open access transmission rules.

Order 888 mandated that transmission owners: provide third parties with open, non-discriminatory access to transmission facilities; provide transmission service at cost-based prices;

[5] Nationally, PURPA resulted in over 60,000 MW of new generation from QFs. In New Hampshire, approximately 200 MW of QF generation, mostly biomass and small hydroelectric, came on-line in the mid to late 1980s.

and use their best efforts to provide new transmission facilities to third parties requesting it and willing to pay the cost of the new or expanded transmission facilities.

During the 1990s, as FERC set rules and guidance in transmission pricing, many parts of the country, especially the northeast and California, moved rapidly at the same time toward restructuring the electric industry to encourage retail competition. Many vertically-integrated electric companies divested their generation assets either to unregulated affiliates or to competitive suppliers. Significant new generation was built in the late 1990s and early part of this decade, but transmission construction lagged significantly until recently.[6]

In Order 2000, FERC strongly encouraged the formation of large, independent regional transmission organizations (RTOs), believing they would provide better coordination of the transmission markets and further promote its policy of more efficient transmission pricing, in part, to resolve transmission congestion problems. With passage of the Energy Policy Act of 2005, the FERC has further sought to strengthen transmission coordination and infrastructure development while supporting competitive electric markets. Its policy continues to evolve, however, as it recognizes the increasing demands of interconnecting a new wave of generators, especially renewable generators spurred by state policies such as Renewable Portfolio Standards (RPS) and the Regional Greenhouse Gas Initiative (RGGI) to address climate change.

In an order dated April 19, 2007, addressing a request for a declaratory ruling by the California Independent Operator Corporation (CAISO) seeking an alternative rate treatment for interconnection costs from the FERC's Order 2003 default interconnection policy, the FERC stated that the "difficulties faced by generation developers seeking to interconnect location-constrained resources [e.g., remotely sited wind facilities] are real, and such impediments can thwart the efficient development of needed infrastructure." While that decision provides promise for states as they undertake efforts to support renewable electric generation, the tension between federal and state regulation continues. Order 2003 established interconnection requirements for public utilities that own, control, or operate facilities used in transmitting electric energy over transmission facilities in interstate commerce to file revised open access transmission tariffs that

[6] According to the Edison Electric Institute, approximately $23 billion in transmission investment has been made since 2000 and its members, based on a survey, expect to spend another $31.5 billion from 2006-2010. In New England, the Independent System Operator expects $6 billion of transmission will be expended on transmission projects from 2003 through 2010(?).

included standard provisions for interconnection as specified by FERC. That decision and a similar one for generators of less than 20 megawatts are under review by appellate courts.

1.2. Overview of the Regional Transmission System

New Hampshire's transmission system is an integrated part of the interconnected New England transmission network, which comprises over 8,000 miles of high voltage transmission lines and interconnects with New York and Canada through 12 "tie lines." This highly complex electrical equivalent of our "interstate highway system" allows for the efficient and reliable transport of electric energy from scores of generation sources to the millions of customer locations where it is used. In New England, the system is operated by the independent system operator, ISO-NE, which, in collaboration with New England's utilities and input from numerous stakeholders through a public process, designs the system to meet increasingly more stringent federal and regional reliability criteria.[7] (See maps on next pages.)

The backbone of the transmission system in New Hampshire, as in New England, is the 345 kV system.[8] PSNH owns and operates 252 circuit-miles of 345 kV lines. Altogether, PSNH's transmission system entails slightly over 1,000 circuit-miles, 743-circuit miles of 115 kV lines and 8 circuit-miles at 230 kV. Its transmission system feeds power through 56 substations throughout the state.

The other major transmission owning utility in New Hampshire is National Grid, which owns and operates 324.5 circuit-miles in the state, of which 267.3 circuit-miles are at 230 kV, 56.55 circuit-miles are at 115 kV and 0.4 circuit-miles are at 69-kV.[9] The 230 kV lines were built around 1930 to export power from the Comerford and Moore hydroelectric facilities on the Connecticut River to southern New England. The National Grid 115 kV line was developed to supply local area load.

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[7] The National Electric Reliability Council, predecessor to today's North American Reliability Council (NERC) was created in 1938 to provide uniform system design and operating standards. It was created in response to the massive east-coast blackout of 1965. Today, NERC writes standards for reliable planning and operation of the high-voltage grid in North America, enforces compliance with its reliability standard and assesses the adequacy and reliability of the of the grid in coordination with ten regional reliability councils. The New England bulk power system is part of one of those regional councils, The Northeast Power Coordinating Council (NPCC).

[8] The distinction between transmission and distribution is not always obvious or uniform, but in New Hampshire as well as New England, the transmission system is considered to include those facilities, such as lines and transformers, used to move power at 69 kV or above.

[9] Florida Power and Light owns a very short section of transmission associated with its Seabrook ownership.

Graphic redacted for security reasons.

Graphic redacted for security reasons.

New Hampshire's high-voltage transmission system also includes a direct current (DC) line that runs nearly the length of the state. The HVDC line was designed to provide mutual assistance between Hydro-Québec and the participants of the New England Power Pool (NEPOOL) during power emergencies as well as to improve the reliability of the bulk power grid for each party to the 1983 Interconnection Agreement. Improved operational coordination and new economical power transactions also were important to the agreement and its approval. The HVDC facilities were originally configured as a 690 MW/2,000 MW tie line constructed in two phases. Phase I, from the Monroe HVDC terminal and now deactivated, interconnected northern New England with the Des Cantons HVDC terminal in Québec. Phase II interconnects central Massachusetts with one of two Hydro-Québec HVDC terminals, either Nicolet and/or Radisson. Phase II is still operational and can import or export power between the two regions. The total transfer capability of the HVDC facilities is rated by ISO-NE in accordance with the Department of Energy permit for the Phase II facilities. Its current import capability is rated at 1,200 MW for firm power. Any amount above 1,200 MW is considered non-firm power.

1.3. Characteristics of Transmission System in Northern New Hampshire

The transmission system in northern New Hampshire is made up of 115-kV lines owned by PSNH. The various circuits were built on contracted rights-of-way (ROW) over a number of years, starting in the 1940s. The 115-kV line, often referred to as the Coos County loop, is made-up of six separate segments. The following table summarizes the key aspects of the Coos County loop:

Line#	Description	Miles	Conductor	Normal Summer Rating (MVA)
D-142	Whitefield-Lost Nation	18.08	336, 795 ACSR	60
Q-195	Whitefield-Littleton	16.15	336, 477 ACSR	120
S-136	Whitefield-Berlin	27.01	795 ACSR	80
U-199	Littleton-X-178	9.01	795ACSR	225
W-179	Berlin-Lost Nation	27.87	336 ACSR	60
X-178	Whitefield-U-199 Tap	14.83	795 ACSR	115

The S-136, W-179, and D-142 lines form a loop from the Whitefield Substation connecting to the Berlin and Lost Nation substations (see map). A 115 kV line, the Q195 line, connects the Whitefield substation to the New England bulk power system through a connection at National Grid's Moore substation and to the Littleton and Beebe substations of PSNH through the X178 line. The normal summer rating of the X-178 line is 230 MVA maximum.

The Coos County loop is connected to National Grid's 230 kV system through PSNH's line to the Moore substation. It also is connected to the National Grid 230 kV system and the Vermont Electric Company (VELCO) 115 kV system through the X-178 line's termination between the Whitefield and Littleton substations. The Whitefield substation also is connected into the 115-kV line going to southern New Hampshire through the X-178 line termination between the Whitefield and Beebe substations.

The existing 115 kV loop is built on the current ROW, predominately 150 feet wide, using H-frame construction. The height of the H-frame structures is 50 – 60 feet.

Northern New Hampshire is generally winter-peaking. Over the last five years, the winter peak load for the Berlin-Lancaster area averaged approximately 70 MW, although it hit a high of 80.2 MW in the winter of 2005/2006. The recent summer peak was 75.4 MW in 2003 and the average peak load for the summer over the last five years is 69.3 MW.[10]

The load carrying ability of the Coos County loop varies based on system conditions, but is generally about equal to the load in the area. PSNH has stated that the existing transmission system in the area is adequate to support the existing load and expected load growth for many years. According to PSNH, the Coos County loop could support approximately 100 MW of new generation in the area without significant transmission upgrades.

All PSNH facilities associated with the Coos County loop shown in the table above are considered non-PTF facilities.

2. The Current Process for Siting, Constructing and Financing Transmission Upgrades and Expansion

2.1. Summary of New Hampshire Siting Statute

RSA Chapter 162-H, originally enacted in 1991, is titled "Energy Facility Evaluation, Siting, Construction and Operation."[11] Among other things, the Legislature in RSA 162-H:1, II, in describing its purpose, declared "that the siting of electric generating plants and high voltage

[10] New Hampshire, overall, is a summer peaking state with a peak load of approximately 2,400 MW.
[11] SB 140 amended RSA 162-H to create a new category of "renewable energy facilities" which have different time frames for review and which may be reviewed by a sub-committee of the Site Evaluation Committee. The discussion here concerns the treatment of a transmission line as a "bulk power supply facility" and does not seek to resolve whether a transmission upgrade to facilitate remote renewables qualifies as an "associated facility" under the definition of "renewable energy facility."

transmission lines should be treated as a significant aspect of land-use planning in which all environmental, economic and technical issues should be resolved in an integrated fashion so as to assure the state an adequate and reliable supply of electric power in conformance with sound environmental utilization."

To effectuate its purpose the Legislature created the Site Evaluation Committee, comprising 14 members drawn from the Department of Environmental Services, the Public Utilities Commission, the Department of Resources and Economic Development, the Department of Health and Human Services, the Fish and Game Department, the Office of Energy and Planning, and the Department of Transportation. The Site Evaluation Committee, through an adjudicative process, is charged with determining whether to grant a Certificate of Site and Facility to an applicant seeking to build a bulk power supply facility or an energy facility.

A bulk power supply facility is defined, generally, as:

1. electric generating station equipment and associated facilities capable of operating at a capacity of 30 MW or more;
2. an electric transmission line rated at 100 kV or more, associated with a generating facility, over a route not already occupied; and
3. an electric transmission line rated at 100 kV or more, longer than 10 miles, over a route not already occupied.

RSA Chapter 162-H establishes procedures and timelines for the filing and consideration of an application for a certificate of site and facility. An application must "contain sufficient information to satisfy the application requirements of each state agency having jurisdiction, under state or federal law, to regulate any aspect of the construction or operation of the proposed facility, and shall include each agency's completed application forms." Each application must also: describe the type and size of each major part of the facility; identify preferred and alternative sites for each major part; describe the impact of each major part on the environment; describe proposals for studying and solving environmental problems; describe financial, technical and managerial capabilities; and document that written notice has been provided to appropriate governing bodies.

Within 30 days after acceptance of an application, the Committee must hold a public, informational hearing in each county where the facility is proposed to be located at which the applicant will present information to the public and to the Committee. Subsequent hearings are adjudicative in nature, consisting of written and oral testimony, cross-examination by parties to the proceeding, as well as questioning by members of the Committee, and are followed by briefs and a written decision by the Committee, which is subject to rehearing and appeal to the New Hampshire Supreme Court. As part of the adjudicative proceeding, the Attorney General appoints Counsel for the Public, who shall "represent the public in seeking to protect the quality of the environment and in seeking to assure an adequate supply of energy."

The Committee has 60 days to determine whether to accept an application, and nine months from acceptance to determine whether to issue or deny a certificate. In order to issue a certificate, the Committee, "after having considered available alternatives and fully reviewed the environmental impact of the site or route, and other relevant factors," must find that:

1. the applicant has adequate financial, technical and managerial capabilities;
2. the facility will not unduly interfere with the orderly development of the region;
3. the facility will not have an unreasonable adverse effect on aesthetics, historic sites, air and water quality, the natural environment, and public health and safety; and
4. the facility is consistent with state energy policy.

With respect to a jurisdictional transmission line, the Public Utilities Commission must also find that the facility is "required to meet the present and future need for electricity" and that it "will not adversely affect system stability and reliability factors."

After a Certificate is issued, the Committee retains enforcement authority over the facility to ensure that the terms and conditions of the Certificate are not being violated. Subject to certain due process requirements, the Committee may suspend or revoke a Certificate.

2.2. New England Independent System Operator Review

ISO New England's Role in the Region

ISO New England Inc. (ISO or ISO-NE) is the Regional Transmission Organization for New England.[12] ISO-NE is a private, not-for-profit corporation, created in 1997, and regulated by the Federal Energy Regulatory Commission (FERC). ISO's primary areas of responsibility include overseeing the reliability of the region's bulk power system, administering the region's wholesale electricity markets, providing regional open-access transmission service, and conducting regional system planning. ISO is governed by an independent board of directors and ISO directors and employees have no financial interest in any of the companies operating in New

[12] www.iso-ne.com. The NHPUC thanks ISO New England for drafting this section.

England's wholesale electricity markets. The ISO also does not build or own generation or transmission facilities.

State and Stakeholder Involvement

ISO develops the Transmission, Markets and Services Tariff (Tariff), operating and planning procedures, and changes thereto, through an extensive stakeholder process.[13] The New England States are active participants in this process through individual state public utility commissions and the New England Conference of Public Utilities Commissioners (NECPUC). The States are also in the process of forming the New England States Committee on Electricity (NESCOE) to provide input to the ISO and the FERC on regional matters.[14] The New England Power Pool (NEPOOL) Participants provide advisory input to the ISO through several stakeholder committees.[15] The ISO's Tariff, which includes the Open Access Transmission Tariff (OATT) and Market Rule 1, are subject to FERC approval.

ISO Responsibility for Regional System Planning

FERC granted ISO responsibility for regional system planning for the six-state region in 2000.[16] To meet this responsibility, ISO conducts the regional system planning process for regional transmission service in coordination with other transmission-owning companies/utilities in New England under the ISO OATT and/or transmission operating agreements. Based on this coordinated and collective effort, the ISO develops an annual Regional System Plan (RSP) that identifies systems needs.[17] In addition, the RSP includes a ten-year forecast of electricity use and peak demand for electricity for New England, the States and multiple sub-areas of New England. The RSP also provides a written assessment of the adequacy of the region's bulk power system infrastructure (i.e., transmission, generation, and demand-side resources) to reliably serve future demand for electricity and meet reliability standards. It also describes the

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[13] http://www.iso-ne.com/rules_proceds/index.html

[14] FERC Docket No. ER07-1324

[15] Participants Committee, Reliability Committee, Markets Committee, Transmission Committee and various subcommittees

[16] While regional coordination of transmission planning and operations have been features of the New England bulk power system for more than 30 years, the establishment of the ISO represented a shift *from* planning for transmission and generation by vertically integrated utilities in a process largely regulated by state commissions *to* regional transmission planning and administration of markets for developing generation by an independent entity (the ISO) in a process regulated by the FERC.

[17] http://www.iso-ne.com/trans/rsp/index.html

regional transmission plan to meet these standards. Among other things, the RSP also describes the fuel mix for generation and analyzes the region's ability to meet state and federal environmental regulations, as well as renewable portfolio standards and carbon emission reductions targeted in the Regional Greenhouse Gas Initiative (RGGI).

New England stakeholders provide input to the regional system planning assessment and process throughout the year through the Planning Advisory Committee (PAC).[18] ISO presents to the PAC the load forecast, the scope and status of ongoing studies of the regional transmission system needs and the development of transmission solutions, and, subsequently, preliminary study results (e.g., resource adequacy analysis, operable capacity analysis, operating reserve requirements, and the impact on reliability during the winter if there is a loss of fuel for generators that only use natural gas).

The regional system planning process is an open and iterative process that culminates each year with an open meeting where the public can provide input to ISO's Board of Directors before the ISO approves the regional system plan. ISO also provides regular updates throughout the year on the status of transmission projects included in the RSP. The regional system planning process has resulted in more than 200 transmission projects totaling $1.2 billion of investment going into service since 2002. Additionally, there is $3 billion to $6 billion of transmission investment expected to be in service over the next decade, based on projects that are either under study or under construction throughout New England.[19] The active participation of the States in the planning process has been instrumental in achieving this success.

Planning is Guided by Reliability Standards

Transmission planning is guided by reliability standards, which are established at the national, northeast and regional levels by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC) and ISO New England respectively. Standards unique to the needs of the bulk power system in New England are embodied in the ISO's reliability standards set forth in the ISO operating and planning procedures. The advent of mandatory reliability standards pursuant to federal legislation passed by Congress in 2005 reinforces the importance of planning for New England.

[18] http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/index.html
[19] http://www.iso-ne.com/trans/rsp/2007/oct07_update_Final_101107_iso-redacted.pdf

Process for Transmission Development

The process for transmission development begins with the identification of system needs through various ongoing needs assessments. The process further leads to the development of possible transmission solutions, defines projects to meet the needs, examines alternatives, and requires ISO reliability and cost approvals of the transmission proposal ultimately advocated by Transmission Owners. Stakeholders provide input throughout this process. This generally occurs as a precursor to the state siting process.

The planning process provides an opportunity for market participants to propose market responses to the needs identified in the RSP and corresponding needs assessments conducted by the ISO. Such market responses include, but are not limited to, generation, demand-side measures, and merchant transmission. ISO is obligated to develop a transmission plan as a backstop for reliability. To the extent that the market responds to address system needs, ISO can modify the transmission plan accordingly. Of importance, the RSP does not constitute an integrated resource plan.

Types of Transmission Upgrades

There are several types of transmission upgrades provided for in the ISO Tariff, including: (1) generation interconnection-related upgrades; (2) Elective Transmission Upgrades; (3) Merchant Transmission; (4) Local Benefit Upgrades; and (5) Regional Benefit Upgrades.[20] Reliability and market efficiency upgrades that benefit the region are included in the category of Regional Benefit Upgrades. Most of the projects in the RSP are identified as Regional Benefit Upgrades. Generator interconnection-related upgrades, which, by their nature are elective, enable new power supply resources to be added to the grid, are not part of the RSP.

Reliability Review

ISO reliability approval is required before a Transmission Owner can connect a transmission facility to the grid. This reliability review is conducted pursuant to Section I.3.9 of the ISO Tariff (the “I.3.9 process”) and applies to all interconnections to the transmission system, including transmission and generation facilities. This review is intended to ensure that a new

[20] http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/index.html

facility would not create adverse impacts on the reliability of the regional transmission system. Reliability review is a precursor to cost review for transmission projects.

Review of Transmission Costs

ISO has responsibility for review and approval of costs for transmission proposed to be included in the regional rate pursuant to Schedule 12C of the ISO Tariff. NEPOOL and the States provide input to the ISO's review of transmission costs.

In 2003, the FERC approved the existing cost allocation process for transmission in New England.[21] ISO and NEPOOL filed the proposal jointly in mid-2003 following an extensive, multi-year stakeholder process that included representatives of the New England States, market participants, transmission owners, and other interested persons.

Regional cost sharing applies to transmission projects that benefit the region. ISO conducts an independent cost review to determine if costs are reasonable, in accordance with good utility practice, and justified for regional cost support. Projects (or elements of projects) that do not provide a regional benefit are deemed "localized" and are not supported by the region.

The region supports the cost of transmission investment based on a share of consumption. Each state's share of consumption affects its contribution to transmission investment in the region. Each state's share, based on network load for the 2006/07 power year is as follows: New Hampshire (9.2%); Maine (8.4%); Vermont (4.1%); Massachusetts (45.5%); Rhode Island (7.0%); and Connecticut (25.7%).

The justification for regional cost sharing is that transmission customers throughout New England benefit from bulk power system upgrades throughout the system especially given the tightly integrated nature of the region's power system. Regional cost sharing only applies to transmission projects rated 115 kilovolts and higher.

Changes to the Transmission Planning Process

FERC issued Order 890 in February 2007, which led to a review of the transmission planning process in New England. The Order requires all transmission providers, including Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), to demonstrate that their existing planning processes are consistent with principles identified by the

[21] Docket No. ER03-1141-000 et al.

FERC, such as having an open, coordinated and transparent planning process on both a local and regional level. ISO has worked with NEPOOL and NECPUC to develop modifications to the process in New England pursuant to Order 890 and ISO plans to file conforming changes in the form of a new attachment to the ISO OATT (Attachment K) by December 7, 2007. Key modifications include establishing a process for developing needs assessments and treatment of market responses in needs assessments, and a process to evaluate potential transmission projects or market responses based on economic benefits to the region.

Process for Generation Interconnection

The administrative and technical study process for generation interconnection is complex. Each project is unique and, therefore, studies must be conducted on a case-by-case basis. The process involves extensive and detailed planning and engineering studies to determine the system modifications necessary to interconnect the generator in a manner that is fully compliant with reliability standards. This requires ISO to coordinate with multiple entities that may be affected by the interconnection, particularly the interconnecting Transmission Owner.

ISO Administration of Generator Interconnections

As the RTO in New England, the ISO is obligated to provide "open access" to the regional transmission system in New England consistent with FERC policy. As such, ISO does not endorse individual generation projects. Any determination of the viability of a generator project in the region's electricity markets is outside the scope of the ISO's review of proposed projects. That assessment is the responsibility of developers of projects.

ISO has responsibility for the administration of the generator interconnection procedures established by the FERC. These procedures apply to all requests for interconnection to FERC-jurisdictional transmission facilities under ISO operating authority. Part of this responsibility includes the obligation to conduct the studies to determine the system modifications necessary to interconnect the new generation.

Generator interconnection studies, as well as studies of other system changes, are conducted in a manner to assure compliance with FERC's orders on generation interconnection, Schedules 22 and 23 of the ISO OATT, and Section I.3.9 of the ISO Tariff. A project seeking interconnection to the grid must successfully complete the generation interconnection process set forth in Schedules 22 and 23 of the OATT, as well as the process established pursuant to Section I.3.9 of the Tariff to ensure against adverse impacts on the tightly integrated regional transmission system. NEPOOL provides technical and advisory input through the Section I.3.9-related process. ISO issues final determinations on all proposals to interconnect generation or implement other changes to the New England bulk power grid.

The Generator Interconnection Study Queue

ISO administers generator interconnection requests, and their associated studies, in the order that they apply (i.e., first come, first served), and projects are assigned a number in the Generator Interconnection Study Queue (the "Queue"). The Generator Interconnection Study Queue is updated regularly on the ISO Web site.[22] The Queue is dynamic. New projects regularly apply to the Queue, and some withdraw. Not every project in the Queue will be built. Since the first publication of the Queue in 1997, approximately 40 generating projects out of more than 200 generator applications have become commercial, adding more than 10,000 MW of generating capacity to the grid. Almost 100 projects, totaling more than 30,000 MW, have withdrawn from the Queue since its inception. There are approximately 100 projects active in the Queue today including projects totaling more than 1,200 MW in New Hampshire.[23]

New Hampshire Projects in the Queue

Project Name*	Fuel Type	Summer Capacity (MW)	Winter Capacity (MW)	County
Hydro Project	Water	169	170	Grafton
Combined Cycle	Natural Gas	563	616	Rockingham
Wind Project	Wind	100	100	Coos
Wind Project	Wind	146	146	Coos
Biomass Project	Wood	56	68	Coos
Biomass Project	Wood	45	45	Hillsboro
Biomass Project	Wood	41	41	Coos
Biomass Project	Wood	41	41	Coos
Biomass Project	Wood	17	17	Grafton
Wind Project**	Wind	24	24	Sullivan
Wind Project**	Wind	34	34	Coos
Landfill Gas**	LFG	6	6	Coos

* Project developers are not revealed until an interconnection agreement is reached.
** Project proposes to connect to the distribution system.

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[22] http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/status/index.html

[23] See footnote 32 below for the source of this slide image.

Minimum Interconnection Standard

Generator interconnection in New England is done according to the FERC-approved Minimum Interconnection Standard (MIS). This standard governs the generation interconnection studies. Under MIS, once a generator is interconnected to the grid, it competes for access to the transmission system by offering into the wholesale energy market. The generator would run if it offered to sell electricity at a lower price than a competing generator. Interconnecting a generator is not a guarantee that it will be able to run if other generation is online. The MIS is described in the ISO's Planning Procedure 5-6.[24] The MIS was approved by the FERC to replace the more-stringent fully integrated standard, which had required all generator output to be capable of reaching all parts of the transmission system. The MIS is intended to promote access to the transmission system, but does not guarantee full deliverability of a generator's output.

Procedures for Large and Small Generators

The Generator Interconnection Process guides how, and under what conditions, new power plants are physically connected to the existing transmission system in New England. The Generation Interconnection Process is based on, with some modifications, the pro forma Large Generator Interconnection Procedures and Small Generation Interconnection Procedures established by FERC in Order Nos. 2003 and 2006. In New England, the FERC interconnection procedures are embodied in the Large Generator Interconnection Procedures (LGIP), which apply to generators larger than 20 MW, and the Small Generator Interconnection Procedures (SGIP), which apply to generators less than or equal to 20 MW. The LGIP and SGIP are set forth in Schedules 22 and 23 of the ISO OATT, respectively.[25]

Generator Interconnection Requests

The ISO's LGIP and SGIP define an Interconnection Request, which generally includes a request to interconnect a new generator to the grid, increase the capacity of an existing generator, or make a material modification to the design or operating characteristics of an existing generator.

[24] http://www.iso-ne.com/rules_proceds/isone_plan/index.html

[25] http://www.iso-ne.com/regulatory/tariff/sect_2/index.html

In accordance with the ISO's interconnection procedures, a developer requesting an interconnection must submit a completed Interconnection Request providing the capacity of the proposed generator; the commercial operation, initial synchronization and in-service dates for the generator; and control of the site at which the project would be developed. The developer must also provide a deposit or processing fee, which differs under the LGIP and SGIP.

As part of the process, ISO arranges for a scoping meeting with developers that submit Interconnection Request. The meeting involves the ISO, the developer, the Transmission Owner, and any affected parties. The developer must execute a study agreement to proceed with the studies agreed to in the scoping meeting.

FERC and State Jurisdictional Facilities

There are two types of jurisdiction for generation interconnections. FERC interconnection rules apply to projects proposing to interconnect to the FERC-jurisdictional transmission facilities administered by the ISO and participate in the wholesale electricity markets. State interconnection rules apply to projects proposing to interconnect to systems that are not FERC-jurisdictional (typically under 69 kV). The Coos County loop is FERC jurisdictional transmission, as would be any likely upgrades.

Interconnection Studies

There are several levels of studies involved in the Generator Interconnection Process.[26] The process requires a Feasibility Study[27], System Impact Study (SIS)[28], and Facility Study[29] that culminate in the negotiation and execution of an Interconnection Agreement.[30] Developers have different options on how to proceed with the Generator Interconnection Study Process. For example, a developer can choose to initiate a Feasibility Study prior to committing to an SIS, or

[26] ISO may designate another party to conduct studies.
[27] The Feasibility Study involves study of power flow, including thermal, voltage and short-circuit analysis, physical feasibility of the interconnection, good-faith estimate of interconnection cost and system upgrade cost, and good-faith estimate of the time needed to construct facilities and system upgrades.
[28] The SIS includes the Feasibility Study, if not done separately, stability analysis, and determination of bulk power system status.
[29] The Facility Study specifies and estimates the cost of the equipment, engineering, procurement, and construction work needed to implement the conclusion of the SIS. The study may be waived in certain cases.
[30] An Interconnection Agreement contains the scope and limitations of an agreement, provisions for inspection or projects, effective dates, cost responsibility, billing and payment arrangements, milestones and financial security, legal provisions for assignment, liability, indemnity, etc., confidentiality provisions, and provisions for disputes, taxes and notices. The templates for the large and small generator Interconnection Agreements are found in the appendices to Schedules 22 and 23, respectively.

pursue both studies simultaneously. The financial commitment is higher if the studies are pursued simultaneously, but this has the advantage of expediting the process. By comparison, a developer may prefer the lesser financial commitment of getting results of a Feasibility Study before committing to the cost of an SIS. Developers may also request optional studies (at their own cost) that include different study assumptions for competing generators based on inputs from the developer. A project may need to be re-studied (at the cost of the developer) if a project higher in the queue drops out of the queue or is modified.

In addition, generator interconnection projects larger than 5 MW require a formal Proposed Plan Application (PPA) after the SIS is complete to comply with the reliability review under the I.3.9 process. Projects smaller than 5 MW simply require notification of project plans to the NEPOOL Reliability Committee. (In addition to reliability reviews, projects must meet requirements for participation in ISO's markets, which are embodied in market rules and operating procedures.)

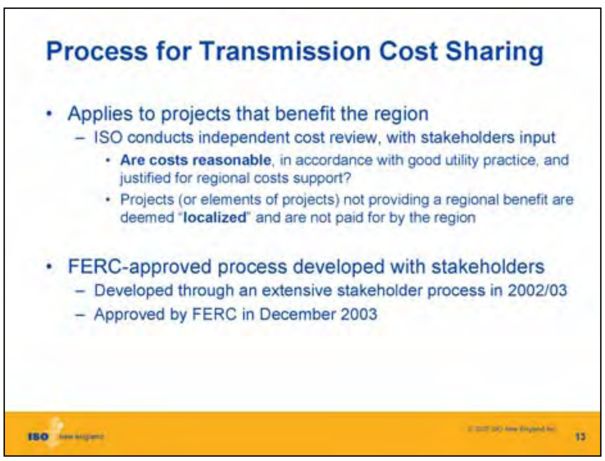
Under New England's competitive wholesale electricity market structure, developers of generator projects are responsible for costs of interconnection studies and any transmission upgrades that ISO determines are necessary to allow a project to interconnect to the grid. Unlike the process for transmission, there is no cost review for generation projects since the costs of these projects are not ultimately passed through to transmission customers through the ISO Tariff.

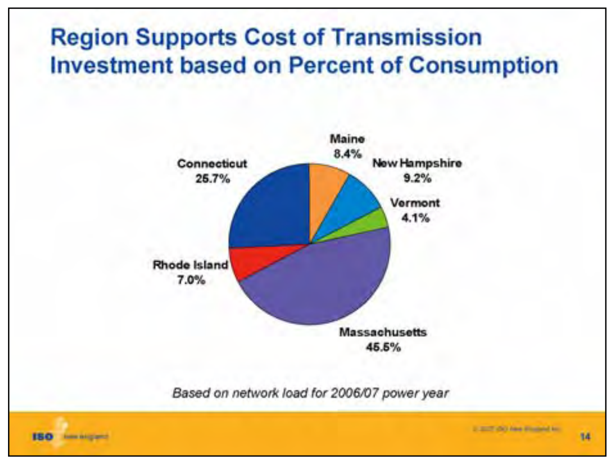
Improving Coordination between the Generator Interconnection Process and the New Capacity Market

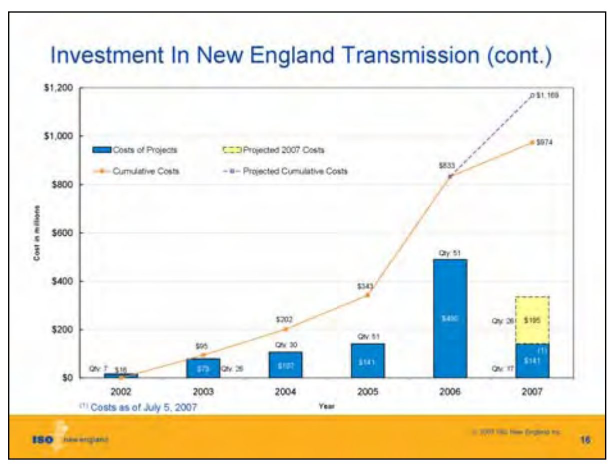
In the qualification process for the new Forward Capacity Market (FCM), when the ISO determines that a generator cannot provide its full amount of capacity due to what is called overlapping impacts with another generator (or the ability to fully deliver the output of both facilities), priority will be given to the resource that entered the Queue first. Review of overlapping impacts is essential to avoid the region buying capacity from a resource that does not provide an increase in the capacity on the system.

A regional stakeholder process is underway to consider options to improve coordination between the requirements of the FCM and the Generator Interconnection Process, both of which have been approved by the FERC. The stakeholder process began in September 2007 and is expected to result in a FERC filing in October 2008. The New Hampshire Public Utilities Commission is an active participant in this process.

Several ISO presentations to the stakeholder group describe the Generation Interconnection Process of yesterday and today.[31] The history of the FERC Generator Interconnection Procedures was presented on October 11, 2007 and the current Generator Interconnection Process was presented on October 25, 2007. The process for qualifying new generation resources to participate in the new FCM, including the FCM qualification interconnection analysis was presented on November 6, 2007. A few key slides from the ISO's presentation at the Electricity Scenario Analysis and Transmission Planning Workshop at NH Legislative Office Building (LOB) are shown below.[32]







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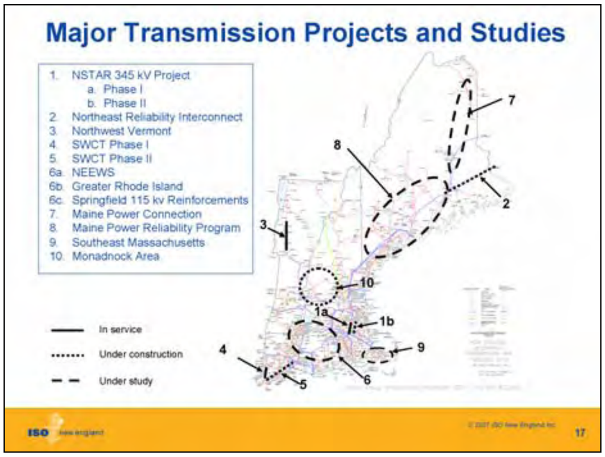
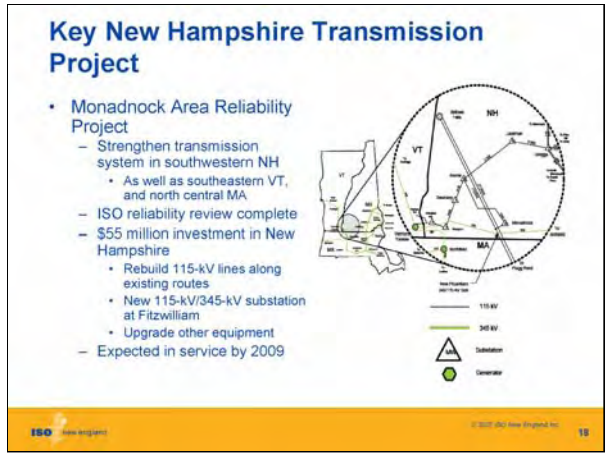
31 Available at: http://www.iso-ne.com/committees/comm_wkgrps/othr/fcm_gen/index.html.

32 Available at: http://www.puc.nh.gov/Electric/Policy/ISO-NE%20Planning%20Presentation%208-28.pdf.





2.3. Financing and Rate Treatment

The financing of transmission upgrades and expansion in New Hampshire has historically been an internal matter for regulated electric utilities. Under both the vertically integrated and restructured models of regulation, utilities in New Hampshire arrange for funds through internal and external sources of debt and equity. Once a project has successfully completed the ISO process and the Federal Energy Regulatory Commission has determined that the costs of the transmission line are reasonable and prudent, and it has been determined whether the costs should be allocated regionally or locally or a combination thereof, the cost allocation is set. Regionally allocated costs are collected through ISO-NE's OATT and paid by all New England ratepayers through retail transmission rates (which may be bundled with generation or distribution rates) while those allocated locally are collected through the local utilities tariff and are paid by that utilities retail ratepayers as part of the local distribution company's transmission and distribution, or delivery rate.

3. The Approximate Costs of Potentially Appropriate Transmission Upgrades

Attempting to determine the cost of new or upgraded transmission without performing a complete, detailed engineering analysis, is not only difficult but provides results which are rough estimates at best. When the amount of new generation precipitating the need for the new or upgraded transmission is unknown or "fuzzy", as is the case in northern New Hampshire, the process is even more involved and less accurate. SB140 does, however, ask for the approximate cost of potentially appropriate transmission upgrades. This section provides four possible options, with price estimates, that could be pursued. It also provides a potential process scenario for planning and constructing new or upgrading existing transmission in the Coos County loop.

3.1. Options to Expand Northern NH's Transmission System to Facilitate Renewable Generation

The PSNH 115-kV transmission facilities that loop through the Whitefield, Lost Nation and Berlin Substations are referred to as the "Coos County loop." To interconnect substantial additional renewable generation resources into this 115-kV transmission system or to interconnect these resources to remote higher capacity transmission substations will require upgrades to existing PSNH and NGrid facilities or the construction of new transmission lines. The extent of the system reinforcements depends on the amount and location of the proposed generation. Since specific siting and resource electrical information is not known at this time, a general planning review of the transmission system was performed to develop potential transmission reinforcement plans and to develop preliminary cost estimates. Once specific generation projects are proposed with detailed resource information, system impact studies will need to be performed in accordance with ISO-NE planning procedures.

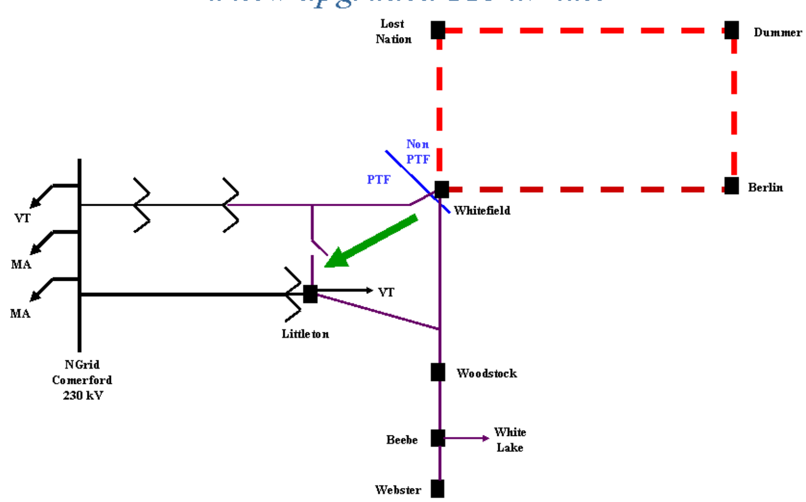
The loop is currently loaded near its limit to allow the reliable transfer of electric power without damaging equipment or creating safety problems. To reliably transfer additional power over these lines, equipment must be replaced or upgraded, although it is possible that up to 60 MW of generation could be accommodated under existing conditions. The least expensive upgrades, which includes a process known as "re-sagging," would cost approximately $10 million dollars and would allow 100 MWs (or an additional 40 MWs) to be interconnected to the loop. This does not include the costs of specific interconnection equipment required to interconnect the new generation resource to the loop. Interconnecting new generation in excess of 100 MWs to the loop, will require more costly upgrades to both PSNH and NGrid transmission systems.

The costs below represent feasibility study grade estimates consistent with ISO generation interconnection policy. These costs could change significantly based on the exact location and characteristics of the new generation resources. The timing and escalation in material prices, siting requirements, and additional costs of electrical equipment required to maintain system stability and voltage (if required) are not included in the estimates.

The following are potential options to upgrade the PSNH and NGrid transmission system. All, except for option IV, assume the existing Coos County loop will have already been upgraded to accommodate 100 MWs of capacity. Therefore, the term “existing loop” herein means existing after being upgraded by re-sagging to carry 100 MWs, which should be sufficient to accommodate the first project in the Queue, i.e., the first Noble wind project. The MW figures below for additional generation resources include the first 100 MW (i.e., 400-500 MW represents 100 MW plus 300-400 MW of additional generation). None of the options would require expanding the existing transmission right-of-way but expansion may be considered to facilitate these and other options.

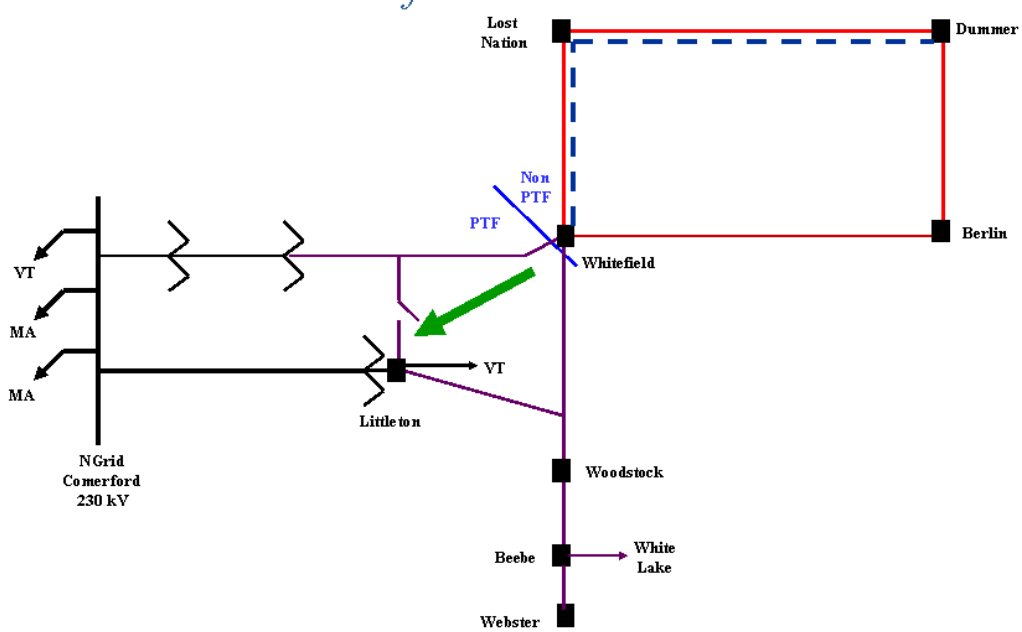
I. To accommodate 400 – 500 MW of additional generation resources interconnected any where into the loop would require rebuilding approximately 73 miles of transmission lines (plus substation upgrades) between Whitefield, Lost Nation (Groveton), Berlin and back to Whitefield. This option would replace the entire existing 115kV Coos County loop with a higher capacity 115 kV line. It would also require PSNH and NGRID to upgrade a portion of their transmission system (approximately 65 miles plus substation upgrades “downstream” of the Coos County loop) to transfer this additional power. The estimated cost of these upgrades is approximately $210 Million. This type of upgrade would allow new generation resources to interconnect anywhere on the loop.

Power Flow for New Generation
Option I
Replace entire existing loop (in red dash) with
a new upgraded 115 kV line

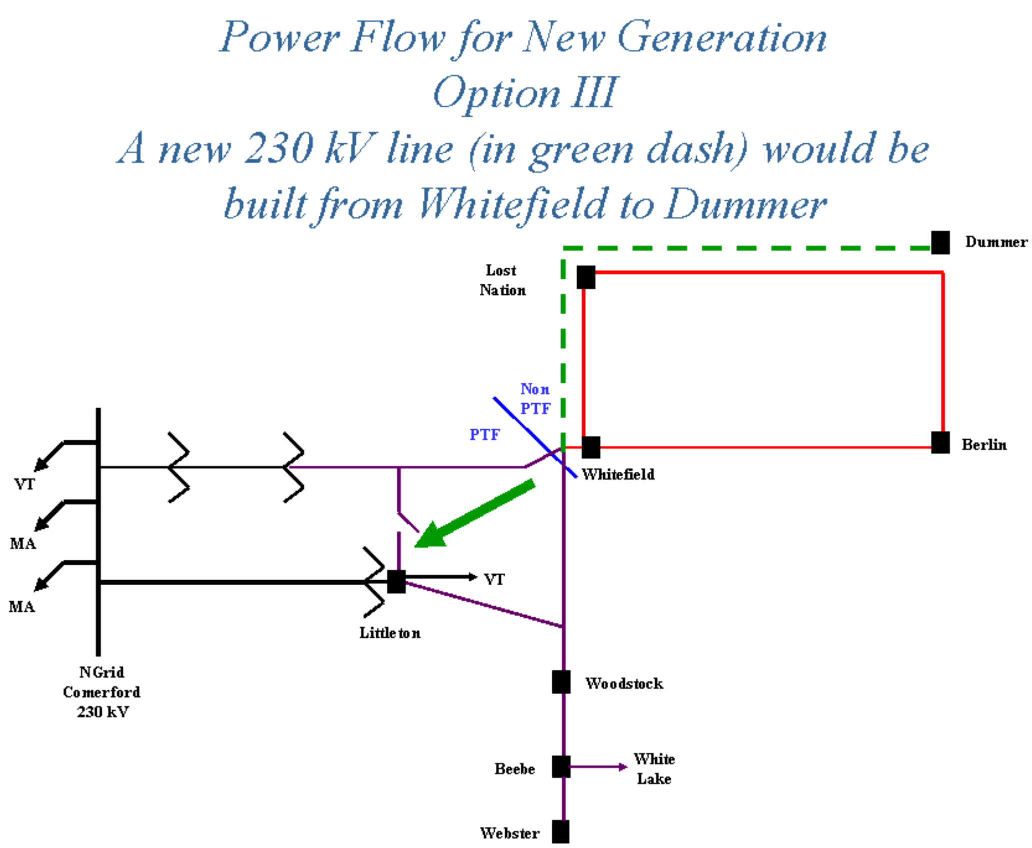


II. To accommodate 400 – 500 MW of additional generation resources mainly located in the portion of the loop from Whitefield to Dummer, a new 115-kV transmission line could be constructed from Whitefield through Lost Nation (in Groveton) ending at Dummer. This would allow the addition of up to 400 MWs of new generation resources to connect to the new 115kV line. It would also allow the option of transferring the 100 MW connection for the first Noble wind project from the existing loop to the new line. This would free up 100 MWs of transmission capacity in the Dummer to Berlin to Whitefield portion of the loop to accommodate new generation there. This plan would still require the same upgrades and new transmission lines south and west of Whitefield. The estimated cost of these upgrades is approximately $170 million. This plan would somewhat limit the siting locations of new generation resources.

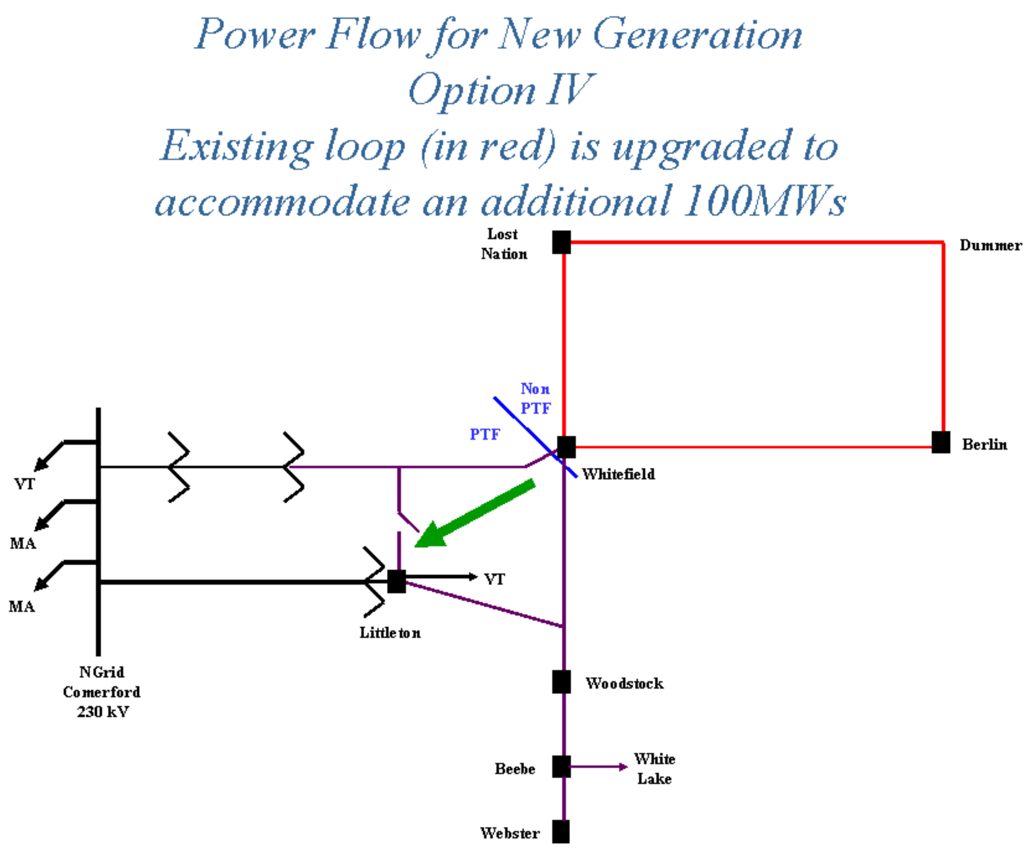
Power Flow for New Generation
Option II
Add a new 115kV line (in blue dash) from
Whitefield to Dummer



III. To accommodate 400 – 500 MW of additional generation resources connecting between Littleton and Dummer, a new higher capacity 230-kV transmission line could be constructed between Littleton and Dummer (50 miles). This plan would require fewer upgrades as compared to upgrading the 115-kV Loop described in Options 1 and 2 above (46 miles of additional line construction, rebuilds, and substation upgrades). New generation resources would interconnect to this new 230-kV transmission line. This plan would also free up 100 MW of additional transmission capacity on the existing loop for other new generation resources provided that the first Noble wind project connection was transferred to the new line. This plan could accommodate over 500 MW of additional generation resources in this area. The estimated cost is approximately $160 million. This plan would somewhat limit the siting locations of new generation resources.



IV. As a potential interim measure, the existing loop could be upgraded to support the first 100 MW Noble wind project, and, pursuant to the ISO-NE Minimum Interconnection Standard (MIS), additional generators would be allowed to interconnect even if available transmission capacity did not exist all of the time. Use of the MIS could allow additional generation to interconnect while transmission upgrades were made. It does, however, limit the output of these units based on system and generation conditions as well as reduce or eliminate the unit's capacity value (in the FCM). Therefore, while this option is theoretically feasible, it may not be acceptable to generators, or, more to the point, their investors or lenders.



3.2. Possible North Country Transmission Scenario

Assumptions

- Upgrading the existing Coos County loop to accommodate 100MWs will be paid for by Noble as part of its first place position in the Queue.
- One of the first three options listed above would be selected. If the option required the first Noble 100 MW wind project to be transferred from the existing line to a new line, Noble would be held harmless with regard to the cost of the transfer. This cost could be included in the overall (total) cost of upgrading the loop
- Connections to all lines would be done to obtain the lowest overall cost for all projects.

- No matter when a generator actually connected into the new or upgraded transmission, they would pay their pro rated share of the total costs including costs for all required studies.
- The cost of upgrading the existing loop and/or building the new transmission line would be paid by the generators who commit to build on a pro rata basis except for the first Noble project as described in 2 above. The cost of any desired surplus capacity would be borne by ratepayers with possible funding sources being the RPS Alternative Compliance Payment funds and the sale of RGGI carbon allowances. If these two sources were not sufficient, the back stop funding mechanism would be the electric rate payers of NH (all ratepayers regardless of to which utility supplies their power)

Process

- This scenario would require legislation including but not necessarily limited to; allowing RGGI allowance sale dollars to be used toward paying for the new transmission line, allowing the PUC to have all utilities collect an additional transmission fee if and when necessary (this is the backstop funding), and finding that the approach is reasonable and prudent.
- A filing with FERC (this may or may not have to been done depending on the specific circumstances) for a change to the existing tariff affecting NH would have to be made. This change would allow the connecting generators to be charged only their pro rata share of the total transmission costs (less the cost for any desired surplus transmission which would be paid by some combination of ACP's, RGGI funds and a ratepayer assessment)
- Perform the initial feasibility portion of the Elective Expansion/Point to Point Request for a predetermined amounts transmission capacity. This study would produce an estimated cost for upgrading to various capacities (e.g., 250 MW's, 350 MW's) and any required downstream upgrades. The cost of these studies would be paid by the generators based on their pro rata share of the proposed new generation. (e.g. if the total amount of new generation that wanted to participate in the study was 350 MW's a 50 MW generator would pay 50/350 of the cost) The cost for this study would be added to the buy-in price on a dollar/ MW basis. At this point the only commitment the participating generators would have is to fund the study
- Once the study from step one was completed, the remaining steps of the Elective Expansion/Point to Point Request (System Impact and Facility Studies) would be performed in the same manor with the generators paying for each step and determining if they wanted to continue in the process after the results were known.

- Generator interest in funding their pro rata share of the actual transmission costs would have to be determined. Based on the interest or lack there of and the amount of surplus capacity if any, that was desired; the amount of new capacity the new/upgraded transmission lines would be built to carry would be determined. Generators would then have to make a commitment to pay their pro rata share of the actual total costs not including the costs of any surplus.
- Once a solid commitment with financial assurance was made by the generators and the amount of surplus capacity determined, the process of designing, permitting and building of the new and upgraded transmission would begin.

3.3. Timing Considerations.

In accordance with ISO-NE interconnection policy and planning procedures, generation owners have the ability to perform system impact studies where the impacts of adding multiple new generation resources are considered simultaneously. These studies with specific generator location, size, and characteristics could take 6-9 months to complete. If certain generators decided to drop out of the clustering process at that point, additional refinements could take up to 3 months. The ISO review process could take an additional 3-6 months. The estimated cost of this effort is $75,000 to $250,000 depending on the issues found during the study process and the time required to resolve them. Once siting approval is received, design, procurement, purchasing material and construction could take 3- 5 years.

4. Approaches Pursued by Other States to Encourage Transmission Expansion Related to Renewable Generation

Many other states face similar challenges to providing needed transmission for new renewable generation. Most of these problems stem from two things: renewable generators tend to be small and they tend to be location-constrained, which refers to generation that, due to its fuel type, is restricted to being built in certain geographic areas. Wind, solar and geothermal generators, which have immobile fuel sources, must be built where the fuel source is located. Other renewables such as bio-mass have slightly more flexibility but, due to the large volume of fuel required, cannot be economically located too far from the fuel source.

Commenting about location-constrained facilities to reporters on November 26, 2007, FERC Commissioner Suedeen Kelly, said: "Our old interconnection process, which is sequential and which requires the first project to pay all the costs of transmission upgrades to bring that project online, is not working well for these renewable projects. … Frequently they require significant transmission expansion and they are rather in a hurry to get built so we need to look at a better process for handling interconnections and we are going to have a technical conference on December 11th to jump start that effort." For example, with more than 220 wind project proposals in the Midwest ISO's queue right now, "you just can't do that one by one by one," Kelly said. She also observed that a number of states, including Texas, are exploring alternative approaches.

4.1. Texas

In 1999, the Texas Legislature passed Senate Bill 7 adopting a Renewable Portfolio Standard but, as noted by the Texas State Energy Conservation Office, "it made no special provisions for transmission to interconnect renewable resources." In 2005, Senate Bill 20 was passed, which facilitates the construction of transmission lines to windy areas of the state. The measure calls for the Texas PUC to designate specific wind-rich zones as CREZ (Competitive Renewable Energy Zones). As of July 2007, eight zones had been designated, mostly in West Texas. Once wind developers show commitment (through a letter of credit amounting to 10% of the project), then transmission companies will build the lines, with the cost allocated 100% to ratepayers across all of the state. A copy of Senate Bill 20 is attached as Appendix B.[33]

4.2. California

California sought to overcome the lumpiness problem of remote generators needing new transmission, but unable to pay for the full cost of the facilities, by having ratepayers pay the cost of the unsubscribed portion of a transmission line until the line is fully subscribed. On April 19, 2007, FERC issued a declaratory order approving a California ISO (CAISO) proposed framework for allocation of the costs of new multi-user trunk facilities for "location constrained resources." FERC noted that such resources are often renewable and have unique needs (since they do not respond to siting signals). In a nutshell, CAISO would roll in the costs of certain trunk facilities built to serve potential renewable generation, and then each generator would pick up its pro rata share of going-forward costs as they come on line. FERC noted that its order should serve as a signal of a policy shift for greater openness on generator interconnection.

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[33] See: http://www.puc.state.tx.us/rules/subrules/electric/25.174/31852adt.pdf and http://www.puc.state.tx.us/rules/subrules/electric/25.174/25.174.pdf.

FERC expressed an interest in adopting similar approaches in other regions. A copy of FERC ruling is attached as Appendix C.[34]

4.3. Colorado

In 2007, Colorado passed a law (SB-07-091) establishing a task force on renewable resource generation development areas. The task force was directed to identify "renewable resource developmental areas within Colorado that have the potential to support industry development among renewable energy developers for development of renewable resource generation projects." A copy of SB-07-091 is attached as Appendix D.

4.4. Idaho

In one of the latest examples of state support for renewable energy development, the Idaho PUC approved in August 2007 a negotiated settlement between wind developers and an Idaho utility (ID Power Co.) allowing wind developers to pay only 25% of the cost of transmission upgrades. For the remaining 75%; the utility would include 25% in its rate base for recovery from ratepayers system-wide. The balance of 50% would be advanced by the developer, but refunded by ratepayers, over a term not to exceed 10 years after the projects are commercially viable. The PUC noted that requiring developer payment of only 25% is beneficial to all customers because it creates an incentive for developers to consider economic efficiencies when they choose locations for their wind farms. The renewable projects will sell their entire output to ID Power, whose customers are spread between Idaho and Oregon. A copy of Idaho PUC order is attached as Appendix E.[35]

4.5. Midwest Independent Transmission System Operator (Midwest ISO)

FERC approved on Sept. 7, 2007 a new tariff revision to generator interconnection for two Transmission Owners (TOs) in the MISO region (ITC and METC), whereby 100% of the upgrade costs resulting from the interconnection is reimbursed to the generator. The corresponding TO will recover this money from the end-users through two different cost allocation mechanisms: 50% allocation on subregional/regional basis depending on the voltage,

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[34] See FERC News release - Item E 5 on April 19, 2007 at http://www.ferc.gov/news/headlines/2007/2007-2.asp.
[35] See page 5 which describes the agreed upon cost allocation mechanism at: http://www.puc.idaho.gov/internet/cases/elec/IPC/IPCE0621/ordnotc/20070829FINAL_ORDER_NO_30414.PDF

with the remaining 50% allocated to that TOs' customers. Although the new proposal is not restricted to renewable generation (it is open to all generation technologies), it is expected that the proposal would encourage the development of renewable resources in line with the Michigan Governor and PUC directions to encourage renewable development. A copy of the FERC order is attached as Appendix F.[36]

5. Actions the Public Utilities Commission Has Taken to Advance New Hampshire Interests With Respect to Transmission

5.1. Actions Prior to Enactment of SB 140

The NHPUC has long been active in advocating for New Hampshire's interests in regional forums and before FERC, including with respect to transmission. RSA 374:F-8 has been the primary source of authority for the NHPUC's advocacy in regional and national forums. Prior to enactment of SB 140 on July 17th of this year it read:

> 374-F:8 **Competitive Market Enhancement.** The commission shall take an active role in advocating for nondiscriminatory open access to the electric system for wholesale and retail transactions. The commission shall participate in the activities of all regional bodies that control the transmission of electricity and shall advocate for needed structural changes that will enhance competitive markets.

A focal point of the NHPUC's efforts has been working with the New England Conference of Public Utility Commissioners (NECPUC) of which it is a member. For the 2004-2005 year, NHPUC Chairman Thomas Getz served as President of NEPUC (a position that rotates between the states). In that capacity and subsequently, Chairman Getz has led an effort to create a New England State Committee on Electricity to more effectively engage the states and represent their interests in the regional transmission planning process and wholesale electricity markets managed by ISO New England. The overall mission of NESCOE is to represent the interests of the citizens of New England by advancing policies that will provide electricity at the lowest possible price over the long term, consistent with maintaining reliable service and environmental quality. NESCOE provides immediate value because it provides the states with a stable,

[36] ITC news link: http://www.itctransco.com/app.php?sec=3&id=37&nid=85. The FERC link to order approving all aspects of ITC's generator interconnection filing, which again essentially would use postage stamp pricing for all network upgrades necessitated by new generator interconnections is: http://elibrary.FERC.gov/idmws/file_list.asp?accession_num=20070907-3051.

relatively well-funded additional resource in dealing with increasingly complex and time-consuming, as well as time sensitive, issues. The FERC, which has encouraged the creation of regional state committees such as NESCOE, issued an order on October 30, 2007, approving NESCOE in concept, and budget approval is expected early in December to allow NESCOE to begin operations in the first quarter of 2008. The costs for the operation of NESCOE, like those of the ISO, will be recovered as part of regional transmission rates. NESCOE will be governed by a board of state officials appointed by the New England governors and is expected to have a staff of 3 during the first year and eventually about 7 total, greatly enhancing the ability of the states to influence regional transmission and wholesale electric market policies.

After Commissioner Clifton Below was appointed to the PUC at the end of 2005, former Commissioner Michael Harrington was hired as Senior Regional Policy Advisor to the Commission. Initially, his participation was focused on the Forward Capacity Market (FCM) settlement discussions. More recently he has been involved in transmission planning issues, attending numerous regional meetings every month and allowing the PUC to be more fully engaged on these matters. Additional activities of the Commission to advance New Hampshire interests with regard to transmission, prior to enactment of SB 140 include:

- Regular participation in ISO-NE/NEPOOL meetings including the Power Supply Planning Committee, the Markets Committee, the Reliability Committee, the Transmission Committee and the Participants Committee.
- Through NECPUC the NHPUC participated in the writing of the NECPUC Staff Report on Transmission Cost Allocation. The report was a result of a January 8, 2008, NECPUC resolution directing the staff electricity policy group to study the pros and cons of transmission cost allocation alternatives that among other things: (1) provide incentives for siting transmission in resource states, and (2) identify beneficiaries of proposed transmission upgrades. This report outlines the current ISO-NE cost allocation methodology, summarizes the methodology for five other Regional Transmission Organizations (RTOs), and explores some alternatives that may be considered to provide incentives for siting transmission in resource states, and identify beneficiaries of proposed transmission upgrades. A copy of the report is attached as Appendix G.
- Through NECPUC, the NHPUC has supported a challenge of the FERC imposed 100 basis point adder above normal market-based rates of return for new investment in transmission, authorized, but not required by the federal Energy Policy Act of 2005.

- The NHPUC is a member and active participant in the National Association of Regulatory Utility Commissioners (NARUC) which provides coordinated educational, research and advocacy services for state commissions, including a number of legal interventions at FERC and in federal courts to protect the interests of the states and preserve state rights in transmission and other issues.
- From the fall of 2006 through the summer of 2007, Commissioner Below served as a NECPUC representative on the ISO-NE's Scenario Analysis Steering Committee, including participation in numerous calls and stakeholder meetings. The Scenario Analysis helps inform the ISO-NE Regional System Plan for transmission upgrades and state policy makers with regard to options to meet the region's future electric needs. The results of that analysis helped to clarify the challenges the region faces in meeting its RGGI greenhouse gas emission reduction goals and point to the need to focus on renewable and other low-carbon resources and imports and consequentially the transmission upgrades needed to enable such resources, in addition to energy efficiency and demand resources, as means to reach these goals.
- Over the course of the past year Commissioner Below has also actively participated in the Northeast International Committee on Energy (NICE) and the Climate Change Steering Committee of the Conference of New England Governors and Eastern Canadian Premiers (NEG/ECP), which has been working on a regional action plan to address climate change and other regional energy issues including the need to upgrade transmission to support no- and low-carbon electric generation sources. He contributed to the development of a set of action recommendations from an NEG/ECP Ministerial Forum on Energy & the Environment which were adopted by the New England Governors and Eastern Canadian Premiers through a resolution on 6/26/07 that calls for numerous actions including, but not limited to: a) quantifying "existing and new non-GHG emitting resources as well as the quantity available for trade in the region;"[37] b) evaluating "interconnect and seams issues that inhibit the cost effective transmission of electricity within the region,"[38] and c) exploring "actions to ease integration of intermittent resources (like tidal and wind power) across the region to expand the amount of renewable power."[39] These interests have been acknowledged by ISO-NE in the 2007 Regional System Plan as described in the next section.

[37] Resolution 31-1 referenced document: *Recommendations and Outcomes – NEG/ECP Ministerial Forum on Energy & the Environment,* Action Item 5a, p. 7, The Conference of New England Governors and Eastern Canadian Premiers, 6/26/07. Available at: http://www.cap-cpma.ca/images/pdf/eng/2007%20Ministerial%20Report%20on%20Energy%20and%20the%20Enviro.pdf.

[38] Id, Action 5b, p. 8.

[39] Id, Action 5e, p. 10.

5.2. Actions Subsequent to Enactment of SB 140

Regional Actions

SB 140 amended RSA 374-F:8 to read as follows effective July 17, 2007:

> 374-F:8 Participation in Regional Activities. The commission shall advocate for New Hampshire interests before the Federal Energy Regulatory Commission and other regional and federal bodies. The commission shall participate in the activities of the New England Conference of Public Utility Commissioners, the National Association of Regulatory Utility Commissioners, and the New England States Committee on Electricity, or other similar organizations, and work with the New England Independent System Operator and NEPOOL to advance the interests of New Hampshire with respect to wholesale electric issues, including policy goals relating to fuel diversity, renewable energy, and energy efficiency, and to assure nondiscriminatory open access to a safe, adequate, and reliable transmission system at just and reasonable prices.

This clarifies and enhances the Commission's regional advocacy role. The Commission has continued to meet and communicate with various New England organizations to discuss and investigate ways to facilitate upgrading and/or building new transmission in NH especially in the northern part of the state. These efforts include:

- Commissioner Below participated in the 10/5/07 meeting of the NEG/ECP NICE where representatives of the eastern Canadian provinces identified some 4,500 MW or more of renewable and no- or low-carbon emission resources that could be available for firm export to New England over the next decade or so, provided that long-term purchase agreements and adequate transmission is available and economic. NICE specifically asked ISO-NE, Hydro-Québec TransÉnergie (HQ), the transmission system operator for Québec, and the New Brunswick System Operator (NBSO) to undertake a coordinated conceptual review of potential transmission upgrades that could support these types of imports. Commissioner Below advocated at that meeting that such a review should include integration of potential renewable generation resources in northern New Hampshire (as well as Maine and Vermont) and an examination of possible synergies between transmission to integrate New England renewable resources and increased import capability from Canada. He also spoke of the potential for Canadian resources to help balance intermittent wind generation resources as inland wind generation tends to have relatively high output during winter peak periods, when Canadian export capabilities are most limited, but relatively low output during summer peaks when Québec has the greatest surplus export capability. Representatives of New Brunswick, Quebéc and Hydro-Québec expressed interest in further studying this possibility, including receptivity to examining possibilities for transmission upgrades to AC lines in the HQ HVDC corridor that might support integration of northern NH renewable generation, increased import capability, and possible tie and reliability benefits and intermittent resource balancing synergies.

ISO-NE has expressed its general support of such effort noting in its 2007 Regional System Plan (RSP07):

> The expansion of wind and hydro resources in eastern Canada and New York may provide an opportunity for additional exports to New England in the long term. This is consistent with the goals of the Northeast International Committee on Energy (NICE), which has sought to reduce the overall emissions of greenhouse gases and to facilitate increased transfers of electrical energy. A study of these issues will be initiated in late 2007 or 2008.[40]

In the Actions and Recommendations section of the RSP07 Executive Summary (pp. 12-13) the ISO also recommends the following steps (among others):

> • **Fuel Diversity and Availability**—Develop diverse energy technologies, such as renewable sources of energy, distributed generation, imports from eastern Canada and New York, and new coal and nuclear technologies.
>
> • **Regional Environmental Goals—**Develop zero- or low-emitting resources, such as renewable resources and "clean" demand-side resources, to ensure that the region meets national, regional, and state environmental and renewable resource requirements.
>
> • **Coordination and Joint Planning with Neighboring Systems—**Work closely with other control areas to improve the coordination of planning efforts. Over the long term, conduct joint planning studies and improve the ability to import power from and export power to the eastern Canadian provinces and New York. Support the Northeast International Committee on Energy sponsored by the Conference of New England Governors and Eastern Canadian Premiers as the group explores initiatives concerning energy and the environment.
>
> • **The Planning Process**—Implement requirements of Order 890 and work with NESCOE, once established, and other stakeholders. In the interim, work with representatives of the New England states, primarily through the PAC, but also through other designated representative organizations, such as the New England Conference of Public Utilities Commissioners (NECPUC) and the New England Governors' Conference (NEGC). Focus planning efforts on the incorporation of demand resources and renewable resources and on market-efficiency needs of the region to reduce costs and use existing resources more efficiently.

- NH PUC also provided comments to the draft RSP07 resulting in the following being added to section 9.3.1.2 on Northern New England Transmission System Studies under the New Hampshire section:

> Additionally, new legislation in New Hampshire, Senate Bill (SB) 140, which was signed into law on July 17, 2007, could influence future transmission needs. SB 140 states that it is in the public interest for New Hampshire to encourage the development of renewable energy. To develop substantial renewable resources, existing transmission infrastructure, particularly in the northern part of the state, will need to be upgraded or replaced, or new transmission facilities will need to be built.
>
> The new law also states that appropriate upgrades to the transmission infrastructure are important to economic development. To further comply with its duties under RSA 374-F-8, the NH PUC must facilitate discussions among interested parties regarding the upgrade of transmission in the northern part of the state and report on these discussions by December 1, 2007. This report must

[40] *2007 Regional System Plan (RSP07),* ISO New England Inc., 10/18/07, p. 11.

address New Hampshire's existing transmission system; the current progress for siting, constructing, and financing transmission upgrades and expansion; the approximate costs of potentially appropriate transmission upgrades; approaches pursued by other states to encourage transmission expansion related to renewable generation; and actions the PUC has taken to advance New Hampshire interests with respect to transmission.

- Participation in the ISO-NE FCM-Generator Interconnection Queue Process Stakeholder Group, which is considering possible changes to the queue process for studying proposed transmission interconnections for new generators.
- Interaction in various venues with the Federal Energy Regulatory Commission (FERC). This includes attendance at the FERC Transmission Planning Technical Conference held on 10/16/07 and planned attendance at the FERC Technical Conference on Interconnection Queuing Practices on 12/11/07.
- Input to ISO-NE on revisions to Attachment K, "Procedures for Regional System Plan Upgrades," to its Open Access Transmission Tariff (OATT), which improves provisions to consider the integration of new resources within regional system planning processes through "economic studies" or a "Needs Assessment" for the integration of new generation sources. ISO-NE is in the final steps of approving the revised Attachment K which calls for prioritization and selection of up to three such economic studies each year with the cost of such studies to be paid for through the overall OATT cost of service.
- **The NHPUC has been advocating for ISO New England to conduct an economic study of transmission to integrate new renewable electric generation, including, in particular, for northern New Hampshire.** The Commission is seeking the support of NECPUC for such a study. The NH proposal has been discussed at the last two NEPUC meetings on 10/18/07 and 11/13/07. There is general support for the idea but a detailed proposed scope of work is still being worked out in talks with other commissions, particularly Vermont. We expect to come to resolution on this within the next month. The overall purpose of such a study would likely be to develop and apply to 3 cases, including northern New Hampshire, a framework to analyze potential transmission upgrades to integrate new renewable electric generation resources, including the possibility of increased imports from no- or low-carbon emission generation resources from outside New England, particularly Québec and the provinces of Atlantic Canada, and to help determine whether or to what extent there is economic justification for including some or all of the cost of such transmission upgrades as "Regional Benefit Upgrades" as a part of the New England Transmission System Pooled Transmission Facilities (PTF).

There is an extra challenge though for the Coos County loop because the present FERC approved ISO-NE transmission tariff does not allow for pooling (or “socialization”) of the cost of upgrading transmission in a loop such as the Coos County loop. Section II.49 of the ISO-NE OATT states, in part, that the following qualify as Pooled Transmission Facilities (PTF): “All transmission lines and associated facilities owned by PTOs rated 69 kV and above, except for lines and associated facilities that contribute little or no parallel capability to the PTF.” The Coos County loop, being a loop, provides no parallel capacity to the PTF and thus is not classified as PTF. Section II.1.118 of the OATT defines Regional Benefit Upgrade(s) (“RBUs”) as a “Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in this OATT…”

Step B5 of Section II, Schedule 12 of the OATT states “The cost for all Regional Benefit Upgrades … shall be included in the Pool-Supported PTF costs recoverable under this OATT for so long as such Transmission Upgrades … continue to meet the definition of PTF under this OAT…” Thus upgrades to the Coos County loop cannot be classified as PTF (unless they result in new parallel capability by connecting to the existing PTF at a point other than Whitefield substation), thus cannot be considered an RBU and are therefore not eligible for region-wide pooled cost recovery as part of the OATT. Upgrading the Coos County loop would normally be classified as an Elective Transmission Upgrade or Generator Interconnection Upgrade. Step B2 of Section II, Schedule 12 of the OATT states that Elective Transmission Upgrades “shall not be included in the Pool-Supported PTF costs recoverable under this OATT, but shall be allocated solely to the entity or entities volunteering to make and pay for such Elective Transmission Upgrades.”

The existing ISO-NE OATT is similar to that in force throughout the country. It is premised on the idea that new generators pay the cost of interconnection to the transmission grid. This protocol has been in place for some time and has worked reasonable well. It is only recently, with the advent of renewable portfolio standards and the resulting concept of “location constrained generation” that this approach has been found lacking. “Location constrained generation” refers to generation sources that are constrained to particular locations due the type of fuel used to power them (e.g wind, geothermal, biomass). As discussed in Section 3.4 , this concern is not unique to New Hampshire and other regions of the country and FERC are trying to deal with this same type of issue.

The results of the proposed ISO-NE economic study may provide the basis for amending the tariff to allow upgrades to transmission such as those needed to allow the Coos County Loop to handle more capacity, to be reclassified as a Market Efficiency Transmission Upgrades (a type of RBU). This could allow them to be eligible to have at least some of the cost of providing the transmission needed to support new renewable generation socialized throughout New England. To the extent that transmission upgrades are likely to be needed to the PTF beyond the Coos County loop, such as west and south of Whitefield, to support integration of renewable resources from the Coos County area, then an economic study will be a prerequisite to determining whether and to what extent the costs of such upgrades should be recovered as part of the PTF as a Regional Benefit Upgrade.

The process of performing this study and any resulting attempt to amend the transmission tariff will be time consuming, with no guarantee of success. The study, furthermore, will take approximately one year to perform. If the results support the pooling of transmission costs for new renewables, the resulting proposed tariff change will have to be vetted through the ISO-NE/NEPOOL stakeholder process and eventually approved by FERC. This process will involve stakeholders who include various agencies in each of the six states as well as generators, transmission owners, and electric power consumers throughout New England.

Bringing this option to fruition may be difficult but can be pursued in parallel with the New Hampshire only (non PTF) options. If and when the tariff changes were approved, the going forward costs of the transmission could be eligible for recovery as part of the PTF of the OATT (regional transmission rates).

New Hampshire Actions

The PUC has held a number of meetings, in addition to numerous calls, conversations and email exchanges, to facilitate discussions among parties interested in the upgrade of electricity transmission in the northern part of the state, including:

8/06/07	Public Meeting with GREAT in Groveton, NH
8/28/07	Meeting with PSNH transmission planning staff.
8/29/07	Conducted public "Workshop on ISO New England Electricity Scenario Analysis & Transmission Planning for the Integration of Renewables" for

	approximately 100 people at the LOB in Concord.[41]
9/18/07	Meeting with National Grid transmission planning staff.
9/24/07	Meeting with representatives for potential North Country renewable generators.
10/1/07	Meeting with PSNH transmission planning staff.
10/9/07	Attended public meeting on transmission for renewables at LOB in Concord sponsored by Senator Martha Fuller Clark
11/5/07	Meeting with National Grid and PSNH transmission planning staff
11/16/07	Meeting with representatives for potential North Country renewable generators
11/20/07	Scheduled Public Meeting with GREAT in Groveton, NH (postponed due to snow storm, rescheduled for 12/4/07)

CONCLUSION

In Senate Bill 140, the Legislature took the first step in the process of informed decision making when it identified as a problem the need to upgrade the electric transmission system in northern New Hampshire in order to accommodate the construction of the sizable wind and biomass generating facilities critical to achieving the benefits of HB 873, the Act Establishing Minimum Renewable Standards for Energy Portfolios, and accomplishing the Governor's "25 by 25" goal for renewable generation. The Legislature took the second step in informed decision making when it instructed the Public Utilities Commission to gather certain facts, as a basis for developing alternative solutions.

As part of the fact gathering exercise, the Public Utilities Commission was directed to do two things by the Legislature in Senate Bill 140, i.e., to "facilitate discussions among the parties interested in the upgrade of electricity transmission in the northern part of the state" and to "file a report" setting forth certain background information describing the physical transmission system,

[41] The presentations from this forum are available at: http://www.puc.nh.gov/Electric/Policy/Scenario_Analysis_and_Transmission.htm.

processes for siting, constructing and financing transmission upgrades, the approximate costs of upgrades, and activity in other states to upgrade transmission to accommodate remote renewable projects.

As noted in Section 5, numerous meetings were held over the past four months with interested stakeholders in an effort to achieve some common understanding about the technical and regulatory issues associated with upgrading the transmission system in the state. Through these meetings proposals were sought from stakeholders on preferred approaches. Although no specific proposals were offered, some participants suggested, in a general way, that non-traditional options be considered. Examples of such options include: (1) allowing a private developer to invest in a transmission upgrade in return for an equity stake in the project and the opportunity to earn a return on its equity investment and (2) creating a public-private partnership with a merchant transmission company that would be allowed to use the utility's existing rights-of-way. While real progress has been made through these discussions in achieving a better understanding among the stakeholders concerning the nature and magnitude of the challenge, more work needs to be done to develop specific alternatives and to produce some consensus around an approach that accommodates sometimes competing concerns about the proper allocation of costs, appropriate levels of risk, timing and other policy choices.

As for the background material contained in the Report, the requested information answers the baseline questions underlying Senate Bill 140, namely: What is the physical status of the transmission system at present? How does the current process for upgrading the transmission system work? How much would it cost to upgrade the transmission system? How are other states addressing this issue? The Report, therefore, memorializes the Commission's fact gathering efforts.

The next step in the process of informed decision making is to develop alternative solutions in order to make the decision. In this regard, it should be acknowledged that there is no single "right" answer to the question of how best to upgrade the electric transmission system in northern New Hampshire to facilitate the construction and operation of renewable energy facilities. Under any approach there are substantial cost and timing obstacles to be surmounted, and selection of the appropriate path depends on one's views regarding a variety of policy preferences and risk factors, as well as resolving regulatory and legal issues that might favor or disfavor one approach over the other. An additional variable concerns the amount of generation that will actually be built, which can lead to significant forecasting uncertainty, considering, among other things, that there are currently no applications pending before the Site Evaluation Committee.

As a next step in the "effort to find a workable solution," it may be useful to reconvene the Northern New Hampshire Electricity Transmission Upgrades Ad Hoc Working Group. The Ad Hoc Working Group was initially established by Senator Fuller Clark as a forum for creative solutions "associated with transporting renewable energy from northern New Hampshire to the rest of the state and the region" and a means "to achieve the upgrades to the system in a rapid fashion as well as alternative methods to finance the project." Consistent with the Ad Hoc Working Group's intentions, and working from the information contained in this report, the time is ripe for stakeholders to present detailed, concrete proposals for the Legislature's consideration inasmuch as most viable options will require some form of Legislative action. The Public Utilities Commission will continue to work with interested stakeholders, assist the Legislature in its efforts to develop a transmission solution for northern New Hampshire, and advocate for New Hampshire's interests with FERC and regional bodies.

GLOSSARY OF ACRONYMS & TERMS

ACP: Alternative Compliance Payments under the RPS.

Alternating current (AC): An electric current that reverses its direction at regularly recurring intervals. (DOE)

Alternative Compliance Payments: Payments made by load serving entities in lieu of meeting RPS requirements.

Ampere: The unit of measurement of electrical current produced in a circuit by 1 volt acting through a resistance of 1 Ohm. (DOE)

Base load capacity: The generating equipment normally operated to serve loads on an around-the-clock basis. (DOE)

Bulk power transactions: The wholesale sale, purchase, and interchange of electricity among electric utilities. Bulk power transactions are used by electric utilities for many different aspects of electric utility operations, from maintaining load to reducing costs. (DOE)

Capacity factor: the ratio of the total energy generated during a specific period of time by a generator to the total possible generation for that period, e.g., a 100 MW unit with an annual capacity factor of 50% would generate 438,000 MWh (100 MW x 8760 hours/year x0.5).

Climate change: A term used to refer to all forms of climatic inconsistency, but especially to significant change from one prevailing climatic condition to another. In some cases, "climate change" has been used synonymously with the term "global warming"; scientists, however, tend to use the term in a wider sense inclusive of natural changes in climate, including climatic cooling. (DOE)

Congestion: Electrically, a line that would be overused or exceed its reliability criteria if its flow limit were not enforced. **Congestion:** A condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously. (DOE)

Cost of capital: The rate of return a utility must offer to obtain additional funds. The cost of capital varies with the leverage ratio, the effective income tax rate, conditions in the bond and stock markets, growth rate of the utility, its dividend strategy, stability of net income, the amount of new capital required, and other factors dealing with business and financial risks. It is a composite of the cost for debt interest, preferred stock dividends, and common stockholders' earnings that provide the facilities used in supplying utility service.

Cost of service: A ratemaking concept used for the design and development of utility rate schedules to ensure that the filed rate schedules recover only the prudently incurred cost of providing electric service. This concept attempts to tie the utility's costs of providing service to its customer classes with the revenues it receives from those customer classes.

Cost-of-service regulation: Traditional electric utility regulation under which a regulated utility's rates are based on the cost of providing service, including the utility's overall cost of capital.

Customer choice: The ability and right of customers to purchase energy from a supplier other than their traditional distribution utility.

Direct current: An electric current that flows in one direction.

Distributed Generator: A generator that is located close to the particular load that it is intended to serve. General, but non-exclusive, characteristics of these generators include: an operating strategy that supports the served load; and interconnection to a distribution or sub-transmission system (138 kV or less). (DOE)

Distribution: The delivery of energy to retail customers, usually at voltages less than 69 kV.

DOE: Department of Energy – in this glossary DOE indicates DOE is the source of the definition.

Electric current: The flow of electric charge. The preferred unit of measure is the ampere. (DOE)

Electric energy: The capacity of an electric current to produce work, heat, light, or other forms of energy, usually measured in kilowatt-hours (kWh) or megawatt-hours (MWh).

Electric system reliability: The degree to which the performance of the elements of the electrical system results in power being delivered to consumers within accepted standards and in the amount desired. Reliability encompasses two concepts, adequacy and security. Adequacy implies that there are sufficient generation and transmission resources installed and available to meet projected electrical demand plus reserves for contingencies. Security implies that the system will remain intact operationally (i.e., will have sufficient available operating capacity) even after outages or other equipment failure. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer service. (DOE)

End user: An individual or firm that purchases electric products and services for its own consumption and does not resell the electric products or services.

Energy Policy Act of 1992 (EPACT): This legislation creates a new class of power generators, exempt wholesale generators, that are exempt from the provisions of the Public Holding Company Act of 1935 and grants the authority to the Federal Energy Regulatory Commission to order and condition access by eligible parties to the interconnected transmission grid. (DOE)

Federal Energy Regulatory Commission (FERC): The Federal agency with jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification. FERC is an independent regulatory agency within the Department of Energy and is the successor to the Federal Power Commission. (DOE)

Federal Power Act: Enacted in 1920, and amended in 1935, the Act consists of three parts. The first part incorporated the Federal Water Power Act administered by the former Federal Power Commission, whose activities were confined almost entirely to licensing non-Federal hydroelectric projects. Parts II and III were added with the passage of the Public Utility Act. These parts extended the Act's jurisdiction to include regulating the interstate transmission of electrical energy and rates for its sale as wholesale in interstate commerce. The Federal Energy Regulatory Commission is now charged with the administration of this law. (DOE)

FCM: Forward Capacity Market. This is the newly created capacity market for all of New England.

Generation: The process of producing electric energy by transforming other forms of energy such as thermal (biomass) or kinetic (wind); it also refers to the amount of electric energy produced, expressed in kilowatt-hours or megawatt-hours.

Grid: The components that comprise the transmission network.

HVDC: The high voltage direct current lines connecting Quebec and New England at 450 kV.

Independent System Operator (ISO): An independent system operator whose functions include the safe and reliable operations of the system as well as administering the day-ahead and real-time electric markets.

Interconnected system: A system consisting of two or more individual power systems normally operating with connecting tie lines. (DOE)

Interconnection: The facilities used to connect two power systems; those systems can be two individual control areas or between a generator and a control area.

Intermittent electric generator or intermittent resource: An electric generating plant with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar energy, wind energy, or the energy of free-flowing rivers (that is, run-of-river hydroelectricity). (DOE)

Investor-owned utility (IOU): A privately-owned electric utility whose stock is publicly traded. Its rates are approved by regulators.

Kilowatt (kW): One thousand watts.

Kilowatt-hour (kWh): A measure of electricity defined as a unit of work or energy, measured as 1 kilowatt (1,000 watts) of power expended for 1 hour. One kWh is equivalent to 3,412 Btu.

Load (electric): The amount of electric power delivered to or consumed by customers or end-use devises at specific locations on the system.

Mega (M): Million.

Megawatt (MW): One million watts of electricity or one thousand kilo-watts; a measure of the volume of electric energy, such as the capacity of a generator or transmission line, or the demand of load (users or consumers of electricity).

Megawatt-hour (MWh): One thousand kilowatt-hours. A measure of electric energy produced or consumed. A megawatt hour is a megawatt volume of electricity produced, transmitted or consumed over the course of one hour.

MVA (MegaVolt-Ampre): A measure of the electrical capacity of equipment equal to the product of voltage times the current times 1,000,000.

NECPUC: New England Conference of Public Utilities Commissioners.

North American Electric Reliability Council (NERC): A council formed in 1968 by the electric utility industry to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC consists of regional reliability councils and encompasses essentially all the power regions of the contiguous United States, Canada, and Mexico. See the various NERC Regional Reliability Councils here: http://www.nerc.com/regional/ (DOE)

OATT: The FERC approved Open Access Transmission Tariff.

Peaking capacity: Capacity of generating equipment normally reserved for operation during the hours of highest daily, weekly, or seasonal loads. (DOE)

Power: The rate of producing, transferring, or using energy, most commonly associated with electricity. Power is measured in watts and often expressed in kilowatts (kW) or megawatts (MW). Power equals voltage times current (V x A). Also known as "real" or "active" power.

Power pool: Originally formed by utilities to plan for and coordinate the operation and dispatch of the bulk power pool in order to increase reliability and efficiency.

Power system: all components that taken together form the interconnected grid, including the transmission system, the generators, the distribution system and the loads.

PTF: Pooled Transmission Facility. These are transmission lines, associated equipment and facilities that are controlled by the ISO-NE and whose cost are distributed throughout New England.

Public Utility Holding Company Act of 1935 (PUHCA): This act prohibits acquisition of any wholesale or retail electric business through a holding company unless that business forms part of an integrated public utility system when combined with the utility's other electric business. The legislation also restricts ownership of an electric business by non-utility corporations. (DOE)

Qualifying facility (QF): A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act (PURPA) of 1978. (DOE)

RBU: Regional Benefit Upgrade.

Reliability: A measure of the ability of the power system to deliver power within specified parameters while operating when some lines or generators are out of service.

Re-sagging: the re-tensioning of transmission lines to allow additional electric current carrying capability. Power lines sag when they heat up from hot air temperatures and high levels of current and safe clearances need to be maintained under design conditions.

Restructuring: The process of replacing a monopoly system of electric utilities with competing sellers, allowing individual retail customers to choose their electricity supplier but still receive delivery over the power lines of the local utility. It includes the reconfiguration of the vertically-integrated electric utility. (DOE)

RGGI: Regional Greenhouse Gas Initiative.

Right-of-way: The land and legal right to use and service the land along which a transmission line is located. Transmission line right-of-way is usually acquired in widths that vary with the kilovolt (kV) size of the line. (DOE)

RPS: Renewable Portfolio Standard.

Substation: Facility equipment that switches, changes, or regulates electric voltage. (DOE)

Tie line: A transmission line connecting two or more power systems. (DOE)

Transmission (electric) (verb): The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer. (DOE)

Transmission line: A set of conductors, insulators, supporting structures, and associated equipment used to move large quantities of power at high voltage, usually over long distances between a generating or receiving point and major substations or delivery points. (DOE)

Transmission system (electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers or is delivered to other electric systems. (DOE)

Vertically integrated utility: a utility that owns and operates more than one part of the electric system. Historically, the regulated utility owned generating plants and the transmission and distribution system.

Volt (V): Unit of electrical pressure.

Watt (W): Unit of electrical energy flow or power equal to one ampere under a pressure of one volt.

Wind energy: Kinetic energy present in wind motion that can be converted to mechanical energy for driving pumps, mills, and electric power generators. (DOE)

Wind power plant: A group of wind turbines interconnected to a common utility system through a system of transformers, distribution lines, and (usually) one substation. Operation, control, and maintenance functions are often centralized through a network of computerized monitoring systems, supplemented by visual inspection. (DOE)

Wind turbine: Wind energy conversion device that produces electricity; typically three blades rotating about a horizontal axis and positioned up-wind of the supporting tower. (DOE)