NECPUC Staff Report on Transmission Cost Allocation

Pursuant to January 8, 2007 NECPUC Resolution

June 15, 2007

This report was authored by staff of State Commissions of the six NECPUC states and does not reflect the views of NECPUC, any State Commission or any Commissioner. The issues discussed in this report may or may not be taken up by NECPUC and/or its individual State Commissions or Commissioners. This report is subject to revision.

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I. RESOLUTION

The January 8, 2008, NECPUC resolution[1] directs the staff energy 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.[2] In total 6 RTOS are examined: ISO-NE, Southwest Power Pool ("SPP"), Midwest ISO ("MISO"), PJM Interconnection ("PJM"), New York ISO "NYISO" and California ISO ("CAISO").

In order to accurately assess the cost allocation methodologies of various RTOs, it is important to understand the foundations from which the methodologies were developed. Each RTO inherently possesses a unique set of physical characteristics, market dynamics and historical perspective that may have been taken into account during the development of their respective cost allocation methodologies. More detailed characteristics are included in each RTO summary.

[1] The resolution is appended as Attachment 1, to this report.

[2] The study does not focus on the methodology for generator interconnection upgrades, the methodology that is addressed in Schedule 11 of the ISO OATT. This methodology was developed in separate proceedings from those addressing transmission expansion upgrades, and was accepted by FERC. The study does touch on a recent decision involving a new approach for funding interconnection of remote renewables, however, because related cost allocation measures can have an effect on siting new transmission in resource states.

II. FERC PRINCIPLES OF TRANSMISSION COST ALLOCATION

On February 16, 2007, FERC issued its Final Rule in Preventing Undue Discrimination and Preference in Transmission Service, 118 FERC ¶61,119 (2007) ("Order 890"). As part of the Final Rule, FERC addressed the issue of cost allocation principles for new transmission projects to provide greater certainty and support for the construction of new transmission infrastructure. *Id.* ¶ 552. These principles may be helpful to guide the Commissioners as they consider possible transmission cost allocation alternatives to the current ISO-NE methodology. According to FERC, transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs. *Id.* ¶ 557.

Perhaps the first principle FERC set forth is that FERC will not impose a particular allocation method, but instead "will permit transmission providers and stakeholders to determine their own specific criteria which best fit their own experience and regional needs." ¶ 558. Nevertheless, FERC stated its belief that some overall guidance is appropriate. *Id.*

> First, we consider whether a cost allocation proposal fairly assigns costs among participants, including those who cause them to be incurred and those who otherwise benefit from them.
>
> Second, we consider whether a cost allocation proposal provides adequate incentives to construct new transmission.
>
> Third, we consider whether the proposal is generally supported by state authorities and participants across the region.
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> * * *
>
> These three factors are interrelated. For example, a cost allocation proposal that has broad support across a region is more likely to provide adequate incentives to construct new infrastructure than one that does not. The states, which have primary transmission siting authority, may be reluctant to site regional transmission projects if they believe the costs are not being allocated fairly. Similarly, a proposal that allocates costs fairly

> to participants who benefit from them is more likely to support new investment than one that does not. Adequate financial support for major new transmission projects may not be obtained unless costs are assigned fairly to those who benefit from the project.

Id.

The Commission has cited these principles in recent cost allocation orders. See, e.g., *PJM Interconnection, LLC*, 119 FERC ¶ 62,063 (20007).

FERC stated that these principles are particularly important when applied to transmission upgrades to reduce congestion or enable groups of customers to access new generation. According to FERC, the beneficiaries of such projects, as a general matter, should agree to support them. However, FERC recognized the "free rider" problem associated with new transmission investment where customers who do not agree to support a particular project may nonetheless receive substantial benefits from it. *Id.* at ¶ 561.

FERC observed that in the past different regions have attempted to address such issues in a variety of ways, such as by assigning transmission rights only to those who financially support a project or spreading a portion of the cost of certain high-voltage projects more broadly than the immediate beneficiary/supporters of the project.

> We believe that a range of solutions to this problem are available. We therefore continue to believe that regional solutions that garner the support of stakeholders, including affected state authorities, are preferable. Moreover, it is important that each region address these issues up front, at least in principle, rather than having them relitigated each time a project is proposed. Participants seeking to support new transmission investment need some degree of certainty regarding cost allocation to pursue such investments.

Id.

ISO-NE has posted its initial strawman in response to Order 890.[3]

III. ISO-NE COST ALLOCATION METHODOLOGY

A. Background

At the beginning of the current decade, New England stakeholders, including state regulators, began a discussion on the issue of cost allocation of transmission expansion and transmission upgrades. FERC was also considering this topic, and in an Order issued December 20, 2002 in the Standard Market Design proceeding, Docket ER02-2330, granted the joint request for rehearing/clarification by NEPOOL and ISO-NE that they not be precluded from developing a cost allocation proposal that provides regional cost support for network upgrades.[4]

ISO-NE facilitated a stakeholder process in the late 2002 through early 2003 period. The stakeholder process was open to all interested parties. Stakeholders identified a list of principles to guide the development of a cost allocation methodology. [5] This list included the following concepts that "cost allocation method should: (1) consider the multiple benefits of the facility over its full life; (2) encourage proper investment; (3) send appropriate price signals relative to the SMD market; (4) be perceived as fair and equitable to transmission customers; (5) provide price certainty to investors and customers; and (6) provide for ease of implementation."[6] Stakeholders

[3] The ISO-NE Strawman is available at the following link: http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2007/may162007/index.html.

[4] July 31, 2003 Filing at 2.

[5] The states never developed their own set of principles.

[6] July 31, 2003 Filing at 3.

reviewed several cost allocation proposals including approved cost allocation methods in other parts of the United States. On July 31, 2003 the results of the stakeholder consensus process were filed with FERC.

New England's Open Access Transmission Tariff [7] provides that transmission owners (TOs) offering service over the pool transmission facilities are compensated through either Regional Network Service (RNS)[8] or Local Network Service (LNS)[9]. RNS expenses are recovered from all customers in New England. LNS expenses are recovered from customers of a specific TO.

B. FERC Procedural History of Current Methodology

In accordance with FERC's guidance on addressing the allocation of transmission costs, NEPOOL and ISO-NE instituted a regional process to resolve New England's cost allocation issue. In early 2003, ISO-NE led a series of workshops attended by a broad group of stakeholders. The stakeholders reviewed several default cost allocation proposals, including a proposal from the Maine and Rhode Island public utility commissions. After considerable discussion and effort by stakeholders, NEPOOL ultimately approved and supported New England's current cost allocation methodology by a 78% vote on July 31, 2003.

On July 31, 2003, NEPOOL and ISO-NE jointly filed transmission cost allocation amendments in Docket No. ER03-1141. NEPOOL and ISO described the mechanism for allocating costs when no party voluntarily assumed the cost of the

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[7] Schedule II of ISO New England FERC Electric Tariff 3.

[8] See Section II.B of Schedule II of ISO New England FERC Electric Tariff 3 for a complete description of Regional Network Service.

[9] See Schedule 21 of Schedule II of ISO New England FERC Electric Tariff 3 for the main substantive provision applicable to Local Network Service.

upgrade (the default cost allocation) as objective and non-discriminatory and consistent with the principles of cost causation.[10] NEPOOL and ISO stated that these amendments to the tariff were developed collaboratively through "a fully inclusive and extensive stakeholder process." NEPOOL and ISO-NE further stated that the proposed TCA Amendments were consistent with Commission directives and policy.

As an offer of Settlement, the Maine and Rhode Island Commissions proposed an alternative hybrid methodology in which a percentage of upgrade costs were regionalized; however, this proposal was not adopted by the Participants' Committee. In response to the Filing, a coalition of Rhode Island and Maine state parties and generation and demand response companies filed a Complaint proposing a hybrid methodology similar to that proposed in the stakeholder process.

On December 18, 2003, FERC approved the NEPOOL/ISO-NE transmission cost allocation methodology and rejected the coalition's alternative. FERC found the NEPOOL/ISO-NE filing was just and reasonable, and characterized the cost allocation methodology as "the choice of the region."[11] Several parties sought rehearing, and on December 2, 2004, FERC issued an order on rehearing, affirming its approval of the methodology, emphasizing that the methodology was a "reasonable default approach for assigning costs of new transmission facilities when parties do not generally agree on the beneficiaries."[12] Further, FERC held that the methodology will ensure regional cost support for upgrades that provide region-wide benefits, is consistent with NEPOOL's

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[10] Applicants' July 31 Filing at 16.

[11] *New England Power Pool and ISO New England, Inc*., 105 FERC para. 61,300 (2003). Central Maine Power Company subsequently filed a petition for review with the Court of Appeals for the District of Columbia, which was dismissed on June 14, 2004 as premature.

[12] *New England Power Pool, et al*., 109 FERC para. 61,252 (2004).

pool transmission facilities rate structure, and is not inconsistent with locational marginal pricing. FERC also stated:

> Although the approach favored by Central Maine, under which economic upgrades provide system-wide benefits only if they provide benefits equally to each sub-region of New England, or the approach favored by the Coalition, under which economic upgrades would receive 75 percent participant funding and 25 percent regional cost support, might also yield reasonable results, the test for the Commission is whether the approach proposed by the utility, NEPOOL and its partner ISO-NE, is just and reasonable in itself. The Commission finds that it is.

Id.. No party sought judicial review of the rehearing order, which is final and non-appealable.

C. State Regulatory Positions taken in FERC proceeding

At the time of the Commission's approval of ISO-NE's and NEPOOL's proposed cost allocation methodology, the New England states had not reached any consensus on an appropriate cost allocation methodology. The Connecticut and Massachusetts commissions supported regionalization of transmission costs. According to Massachusetts and Connecticut, new transmission benefits the entire region. The Maine and Rhode Island commission's proposed a "beneficiaries pay"[13] mechanism and the Vermont Commission had proposed an alternative proposal for economic upgrades. New Hampshire did not take a position on either the NEPOOL-ISO proposal or the other proposals.

[13] The term "beneficiaries pay" is used by FERC generally to mean a methodology that allocates expansion costs to those zones that directly benefit from the upgrade. *PJM Interconnection, LLC*, 119 FERC ¶ 62,063 P. 4 ("We continue to support PJM's "beneficiary pays" approach of allocating the costs of new, PJM-planned transmission facilities. Under this "beneficiary pays" approach, direct beneficiaries of a particular transmission upgrade are identified and directly allocated the costs of that upgrade. We find that, by allocating costs according to these benefits – benefits that flow from these investment decisions – we promote the development of optimal electricity infrastructure").

D. Definition of Reliability and Economic Upgrades and Allocation of Upgrade Costs

The ISO-NE Transmission, Markets and Services Tariff ("ISO-NE OATT") identifies various categories of upgrades and assigns the applicable transmission cost allocation mechanism for each upgrade. Under the current methodology, two types of upgrades qualify as Regional Benefit Upgrades (RBUs) to receive cost recovery through regional rates. To qualify as an RBU, a project must be included in ISO-NE's Regional System Plan (RSP) as either a Reliability Transmission Upgrade (RTU) or a Market Efficiency Transmission Upgrade (METU). An RTU is defined as:

> Those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of NERC and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.[14]

METUs also qualify as RBUs. Specifically an METU is defined as:

> Those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For

[14] ISO-NE OATT Section II.1.126.

> purposes of this definition, the term "bulk power system costs to load system-wide" includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.[15]

Attachment N to the OATT contains additional information about the standards for identifying RTUs and METUs.

Costs are not regionalized, and instead are localized, for RBUs where the incremental costs of the upgrade exceed those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. These costs are called Localized Costs. Localized costs are those portions of a reliability transmission upgrade or market efficiency transmission upgrade that the ISO determines exceed the costs of reasonable requirements that are specified in Schedule 12C of the ISO-NE OATT and Planning Procedure No. 4. [16]

Specifically, localized costs[17] are defined as:

> The incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of this OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation,

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[15] ISO-NE OATT Section II.1.67.

[16] To date there have been two localized cost determinations for major projects (Reliability Transmission Upgrades). For example, in the SWCT Phase I project (Bethel-Norwalk), much of the incremental costs of underground transmission over the cost of the overhead alternative were determined to be localized costs.

[17] Localized costs should not be confused with the costs of a local benefit upgrade, which is defined as:

> An upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in this OATT.

ISO-NE OATT Section II.1.51.

> efficiency and reliability of the proposed Transmission Upgrade. Prior to any recovery of costs under this OATT associated with a RTEP02 Upgrade or a Regional Benefit Upgrade, the ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.[18],

In addition, upgrades below 115kV and those upgrades of 115kV or above that do not meet the tariff-specific criteria as Pool-Supported Transmission Facilities (PTF) are considered Local Benefit Upgrades with costs not allocated regionally. [19]

The current cost allocation methodology also provides for Elective Transmission Upgrades, where the upgrade is participant funded (i.e., voluntarily funded by an entity or entities that have agreed to pay for all of the costs of such upgrade).

If a transmission upgrade is classified as either an RTU or an METU, the costs of the upgrade are recovered on a regional basis if the upgrade meets the ISO-NE criteria, is rated 115kV or above, and is not a radial transmission line. (See definition of Regional Benefit Upgrade (RBU) at ISO-NE OATT at § II.1.118 and Schedule 12 § B(7) to the ISO-NE OATT.)

E. The Regional Planning Process

The ISO-NE OATT provides for a review and approval process for inclusion of transmission upgrades in the Regional System Plan (RSP). The tariff defines the purpose of the RSP as follows:

> The purpose of the RSP is to identify system reliability and market efficiency needs and types of resources that may satisfy such needs so that Market Participants may provide efficient market solutions (*e.g.*, demand-side projects, distributed generation and/or merchant transmission) to identified needs. The purpose of the RSP is also to assess

[18] ISO-NE OATT Section II.1.63.

[19] ISO-NE OATT Schedule 12 § 6.

> the ability of proposed market solutions to address identified needs with due cognizance of the operational characteristics of those proposed market solutions and to identify a regulated transmission solution to be built by one or more PTO(s) in the event that market responses do not meet identified needs or that additional transmission infrastructure may be required to facilitate the market. [20]

The ISO-NE develops the RSP in close consultation with the Planning Advisory Committee (PAC). Stakeholders and state regulators may participate in the PAC. In addition, a subcommittee of the ISO-NE Board of Directors convenes a public meeting to review the proposed needs assessment as part of the RSP process.

The RSP process directs ISO, with input from the PAC, to:

> provide an annual assessment of the system needs of the New England Control Area in a consolidated manner, and is designed to maintain the New England Control Area's reliability while accounting for market performance, economic and environmental considerations. At least every three (3) years, the RSP shall reflect the results of a new comprehensive system planning and expansion study conducted pursuant to Section II.48.4 of this OATT. In other years, the RSP may be only an update to a prior-approved RSP. Comprehensive system enhancement and expansion studies include a needs assessment by the ISO (as described in Section II.48.4(d)) of this OATT, and the ISO analysis of the market and regulated transmission solutions in response thereto (as described in Section II.48.4(e) of this OATT).
>
> The RSP shall utilize at least a five year planning horizon, and reflect at least five year capacity and load forecasts. The RSP shall identify, based on the results of system enhancement and expansion studies conducted pursuant to Section II.48.4 of this OATT, a list of proposed Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades to the New England Transmission System for at least each of the ensuing five years, not otherwise proposed as Merchant Transmission Facilities or Elective Transmission Upgrades, that are determined by the ISO to be appropriate at the time of the issuance of the Plan (collectively referred to as "Transmission Upgrades"). Each RSP shall also include the list of Transmission Upgrades included in the prior RSP (including the prior New England Regional Transmission Expansion Plan), as updated, that have not been completed at that time. The lists of Transmission Upgrades shall identify separately: (i) Reliability Transmission Upgrades, and (ii)

[20] ISO-NE OATT Section II.48.1.

> Market Efficiency Transmission Upgrades. The RSP shall describe the projected improvements to the bulk power system that are needed to maintain system reliability and operation of efficient markets under a set of planning assumptions. The RSP shall provide sufficient information, based on the results of system enhancement and expansion studies conducted pursuant to Section II.48.4 of this OATT, to allow members of the PAC to assess the quantity, general locations, operating characteristics and required availability criteria of the type of incremental supply or demand side resources that would satisfy the identified need or that may serve to modify, offset or defer proposed regulated transmission upgrades. The RSP shall also list transmission facilities (as determined under the ISO interconnection process specified in this OATT) to be built to accommodate new generation, merchant transmission, and elective transmission interconnections that have satisfied the requirements of this OATT. The RSP shall also include a description of the reasons for any new Transmission Upgrades proposed in the RSP, any change in status of a Transmission Upgrade in the RSP, or for any removal of Transmission Upgrades from the RSP pursuant to Section II.48.5 of this OATT.

ISO-NE OATT § II.48.3.[21]

F. Transmission Investments

The cost allocation methodology set forth in the ISO-NE OATT has been in place since December 2003. Since that time, the region's transmission owners have constructed a number of major transmission lines approved in the RSP. At this time, approximately $5 billion in new transmission investment is planned or has been made in the last seven years. [22] Examples of recent regional reliability upgrades receiving regional cost support include Connecticut's 345kV transmission loop and Maine's Northeast Reliability Interconnection project. In addition, two projects have been listed as market efficiency transmission upgrades in the RSP: Cape Cod's Project 338, Move Canal 345/115 Auto-transformer to Oak Street, and Project 337, Canal to Oak Street #399 345

[21] NECPUC staff has asked ISO-NE whether any upgrades included in an RSP have ever been removed from a later RSP. Staff will inform the Commissioners about the results of its query, when it receives a response from ISO-NE.

[22] Appended to this report as Attachment 2, is the latest RSP listing. Approximately 75 projects in the list do not yet have costs associated with them.

kV Line. However, these projects are at the concept stage. No analysis has yet been done to determine whether these projects meet the benefits test for a Market Efficiency Transmission Upgrade.

Thus, with the exception of the two projects discussed above, the projects included in the RSP project list are all reliability upgrades. To date, there have been no elective upgrades undertaken in New England.

G. Pros and Cons of ISO-NE Cost Allocation Methodology Listed[23]

1. Pros of ISO-NE Methodology

Table 1: Pros of Current ISO-NE methodology
(Note: This table identifies a comprehensive listing prepared by staff from each state.)

	CT	MA	ME	NH	RI	VT
Recognizes the regional benefits of an interconnected bulk power supply system	✓					
Appropriately takes into consideration that New England is a relatively small geographic region, and that the grid is operated as a tightly integrated power pool in which benefits from transmission projects are likely to be obtained throughout the region		✓				
Supports the regional transmission planning process	✓					
Allows for market-based solutions, including generation and demand response, to meet market needs. (New England transmission owners only build regional transmission if no market solution comes forward.)	✓					
Reduces the risk for non-compliance with NERC Standards	✓					
Is consistent with Order 890 requirements and principles	✓	✓				
Supports projects that import power from neighboring Control Areas	✓	✓		✓		

[23] The following tables set forth the views of the NECPUC staff state-by-state of the pros and cons of the ISO-NE methodology.

	CT	MA	ME	NH	RI	VT
Encourages the development of “backbone” facilities that provide broad, regional benefits	✓	✓				
Will provide the revenue to fund $5 Billion in new upgrades that are completed or have been planned or proposed in the last 5 years					✓	
Has resulted in $5 billion of new upgrades that are completed, planned or proposed in the last 5 years	✓					
Has created sufficient certainty to result in approximately $5 billion of new investment in transmission improvements that are either completed, under construction, or proposed		✓				
As with all cost allocation schemes, it provides the revenue to fund needed system upgrades		✓		✓		✓
Provides regulatory certainty for investors	✓	✓		✓		
Appropriately takes into consideration the fact that over time the costs allocated to sub-regions (e.g., different states) for transmission projects are likely to equal the benefits obtained by the sub-regions		✓				
Avoids litigation over beneficiary determination		✓	✓	✓	✓	✓
Avoids the inherent difficulty in assessing current and future beneficiaries		✓			✓	
Recognizes and addresses the inherent difficulty in assessing current and future beneficiaries in a tight, integrated power pool	✓					
Avoids long, drawn-out litigation over beneficiary determination and limits the potential for large cost shifts among transmission systems	✓	✓				
Decreases the risk of unwanted litigation		✓				
Eliminates the old system of “pancaked” rates that rendered purchases from remote suppliers uneconomic	✓					
Supports the New England Security Constrained Least Cost Economic Energy Dispatch model	✓					
Has been reviewed and accepted by FERC	✓	✓			✓	✓
Has been approved by NEPOOL by a wide majority of participants		✓				

2. Cons of ISO-NE Methodology

Table 2: Cons of Current ISO-NE methodology
(Note: This table identifies a comprehensive listing prepared by staff from each state.

	CT	MA	ME	NH	RI	VT
While there may or may not be a causal connection, there are $5 billion of new upgrades that are completed, planned or proposed in the last 5 years. The reason this is in the con category is the concern over whether there are non-transmission alternatives that are not receiving enough attention because of the "ease" of funding transmission projects			✓	✓		✓
Sharing the cost of projects that reduce congestion costs or eliminate the need for RMR contracts for some states may be seen as inequitable for states that do not share those benefits		✓			✓	✓
Sharing in the costs of projects that primarily benefit other states (in reducing congestion costs or replacing the need for RMR contracts) is seen as inequitable by states that do not share these benefits			✓	✓	✓	✓
May allocate transmission project specific costs to sub-regions within New England that are not proportional to the benefits obtained by such projects within a given sub-region at a particular point in time		✓				
A resource state that will not share in the primary benefits of a transmission line (and may in fact see costs increase both as a result of the transmission cost sharing and increased energy costs) may be reluctant to approve the siting application of such a transmission upgrade. Thus, the siting state has no incentive and in fact has a disincentive to site new transmission that will produce economic benefits (in lower rates) primarily for other states			✓	✓	✓	✓
A resource state may be reluctant to site a transmission line that will cost its ratepayers more in increased prices than they will benefit from the enhanced transmission capacity		✓			✓	

	CT	MA	ME	NH	RI	VT
Combined with the current wholesale electricity market rules, the current methodology may not provide the appropriate incentives for generators to where they are most needed rather than where the costs are lowest					✓	✓
May be inconsistent with the localized cost responsibility afforded supply and demand resources that could serve as lower-cost alternatives to new transmission, potentially resulting in the distortion of decisions made by market participants and state authorities		✓				✓
May not provide the appropriate incentives for high load states to approve siting applications of generation closer to the high load area.	✓		✓	✓		✓
May not provide the appropriate incentives for generators to site where they are most needed rather than where costs are lowest			✓	✓		✓
Distorts the impact of locational price signals by providing regulated regional solutions, funded by all ratepayers, to local and system-wide problems				✓		✓
Pre-empts the goal of locational marginal pricing. Developers of alternative resources would normally choose to capture the economic rents provided by locational marginal price differences. However, building a regulated transmission solution that eliminates those economic rents leads developers of alternative resources to reject building for fear they will lose those rents once a transmission line is built			✓			✓
Does not allow the lowest cost solution to an identified problem to receive the same access to funding resources as the transmission solution. This leads to overall higher costs and overbuilding of transmission compared to more cost-effective solutions				✓		✓
Does not provide a realistic funding method for transmission required by location constrained generation (e.g. wind recourses in remote locations				✓	✓	
Does not eliminate all litigation over cost allocation because the localized cost determinations require extensive ISO and stakeholder resources. Localized cost determinations would not be necessary under a "beneficiaries pays" approach			✓	✓		✓

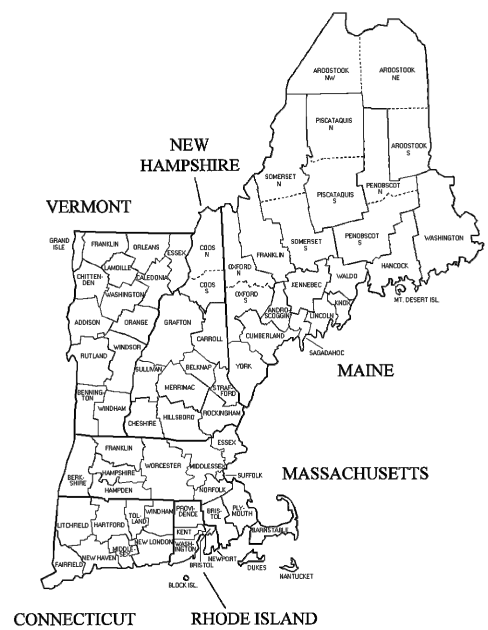
	CT	MA	ME	NH	RI	VT
May be inconsistent with Order 890 cost causation and assignment of costs to beneficiaries principles			✓	✓		✓

IV. DESCRIPTION OF CONTROL AREAS STUDIED IN THIS REPORT.

Descriptions of each of the areas studied in this report are provided below and this information is also reproduced in table form and in maps. No conclusions have been drawn in this report with respect to the linkages between this information and the applicability of any given cost allocation in one region to another region. [24]

A. ISO-NE[25]

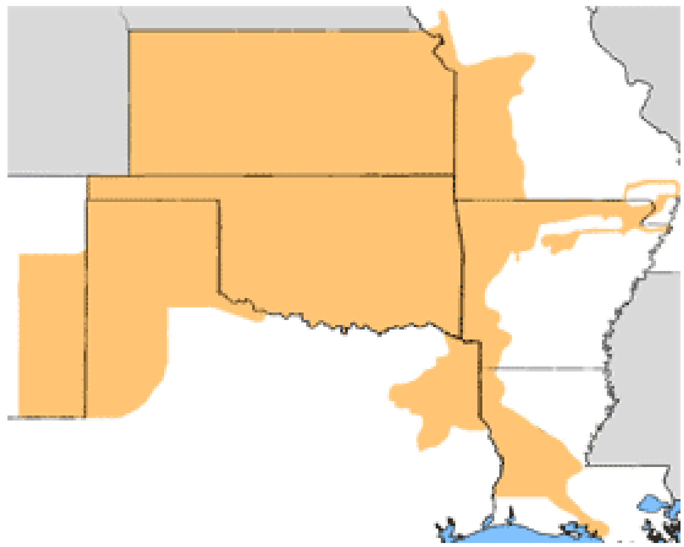
New England operates in a tight, highly-integrated power pool and has a long history of regional planning with 30+ years of integrated planning experience. As one of the first RTOs to embrace Standard Market Design, New England's competitive market structure has progressed further than many areas of the country.



[24] Connecticut and Massachusetts believe that the different characteristics of other regions do affect the applicability of their transmission cost allocation methodology to New England.

[25] ISO-NE is comprised of 6 states - Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. Though reflected on the map, Northern Maine, notably Aroostook and portions of Washington Counties are not part of ISO-NE

B. SPP[26]



The Federal Energy Regulatory Commission (FERC) approved SPP as a Regional Transmission Organization (RTO) in 2004. SPP's market design is significantly different than New England's and lacks the maturity of SMD markets in the Northeast. SPP only operates a real time energy market, has physical transmission rights and has no markets for ancillary services and resource adequacy.

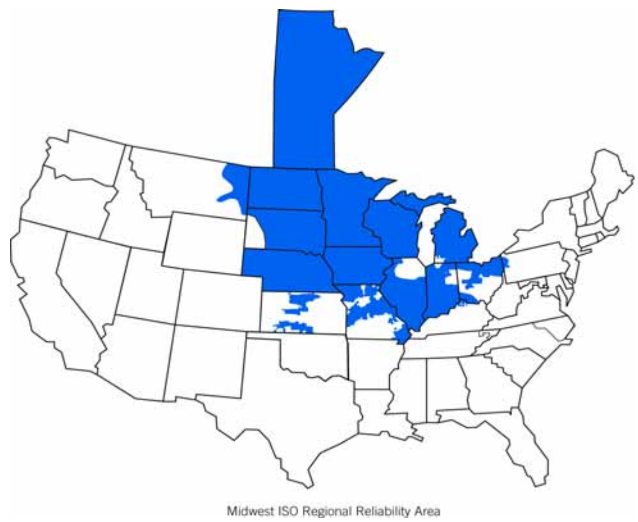
Compared to ISO-NE, the scope of SPP operations is much larger. SPP covers an area (255,000 square miles) more than 3 times larger than ISO-NE, operates more than 6 times as many miles of transmission (52,301 miles) as ISO-NE, and has a peak load that is 1.5 times (42,000 MW) larger than ISO-NE.

SPP's governance roles are also structurally different than New England's. SPP has more limited authority than ISO-NE for tariff administration.

[26] SPP consists of 8 states - Arkansas, Kansas, Louisiana, Mississippi, Missouri, New Mexico, Oklahoma, and Texas. In addition SPP manages transmission 7 of the 8 states.

C. MISO

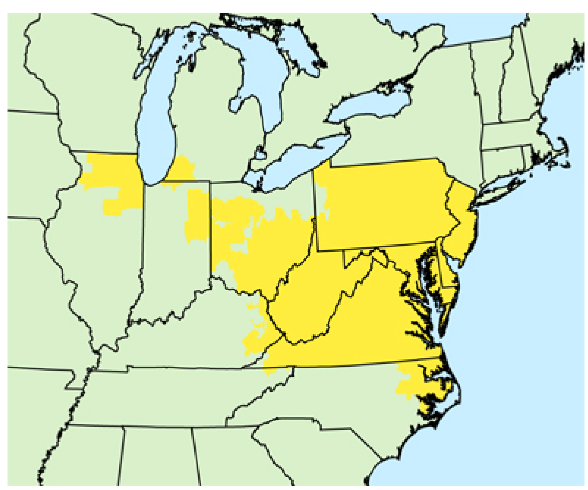
In the Midwest, the geographic scope of the Midwest ISO[27] was a complicating factor in the development of an Order 2000-compliant RTO. Compared to ISO-NE the scope of MISO operations is much larger. MISO covers an area (920,000 square miles) 13 times larger than ISO-NE, operates 11 times as much miles of transmission (93,600 miles) as ISO-NE, and has a peak load almost 5 times (136,520 MW) as that of ISO-NE. In fact each of the MISO sub-regions (Central, East, and West) individually has a peak load greater than that of ISO-NE.



D. PJM

1. Profile of PJM[28]

Generating capacity in PJM is 143,878 MW, 4.6 times larger than NE (30,958). The control area includes parts of 13 states and the District of Columbia, more than 164,000 square



[27]MISO consists of 15 states and the Canadian province of Manitoba.

[28]PJM includes 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia) and the District of Columbia (DC).

miles, serving approximately 51 million people. The transmission system backbone varies by geography / sub-region and includes:

* 765 kV in Southwestern areas
* 500 kV in Eastern areas
* 345 kV in Northwestern areas

PJM in its current form is a relatively new organization; the original "PJM classic" footprint has doubled.

2. Comparison of PJM and ISO-NE Generation Mix

	PJM	**NE**
* Coal	42%	9%
* Gas/oil	35%	63%
* Nuclear	19%	14%
* Other	4%	13%

3. Regional Planning

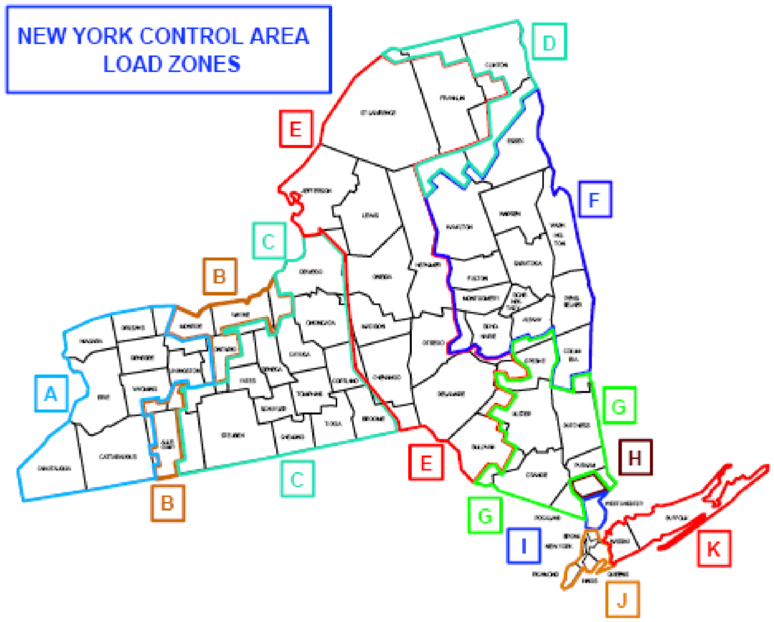
PJM has filed for 3 NIETC corridors to address multi-state projects. Expansion planning and reliability studies are based on a sub-regional approach, with the following sub-regions:

* Eastern & Central PJM
* Southwestern PJM
* Western PJM
* Southern PJM

PJM uses a15-year planning horizon.

E. NYISO

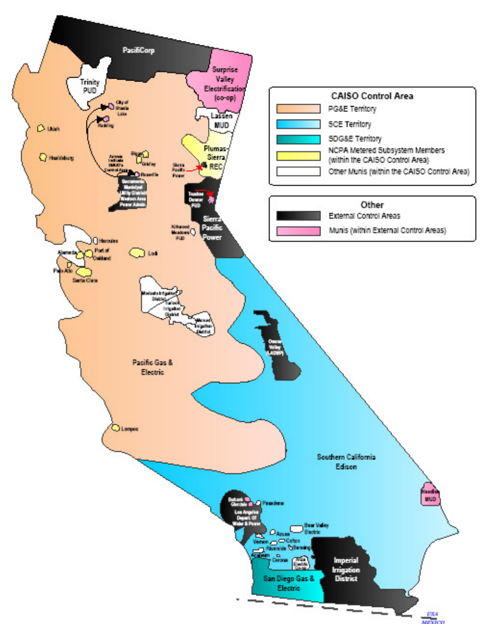
The NYISO is a single state control area, 47,225 sq. miles in size. It has 10,775 miles of transmission lines. Like ISO-NE, NYISO's generation mix is predominantly gas (126 units). It has some coal units as well (51).



F. CAISO

California is a single state control area. The CAISO control area includes much of the state of California. The other control areas in California are made up of the public power systems of Los Angeles and Sacramento and the Imperial Irrigation District. CAISO assumed command of California's wholesale power grid on March 31, 1998.

CAISO Internal Utilities and External Control Areas



The CAISO-controlled portion of the state's power grid covers 25,526 circuit miles or three quarters of the state. Approximately 200-billion kilowatt hours of electricity are delivered each year.

Transmission expansions approved by the CAISO since 1998 include 340 projects for an estimated total cost of $4.44 billion. CAISO covers an area almost twice the size of ISO-NE, operates more than three times as many miles of transmission as ISO-NE, and has a peak load that is almost twice as large as ISO-NE.

The two tables below describe the physical and market characteristics of the five RTOs as compared to ISO-NE.

Physical Characteristics				
RTO	***Geography***	***Miles of Transmission***	***Peak Load***	***Generation***
ISO New England	– 6 states – less than 69,746 square miles	– over 8,000 miles	– 28,130 MW	– over 350 units – About 12% of the fuel mix is coal – About 42% of the fuel mix is natural gas (with and without oil storage)
Southwest Power Pool	– 8 states – 255,000 square miles	– 52,301 miles	– 42,000 MW	– 451 generating units – About 40% of the fuel mix is coal
Midwest ISO	– 15 states and one Canadian province – 920,000 square miles	– 93,600 miles	– 136,520 MW – Each of the three sub-regions peak is greater than 30,000 MW	– 5,173 generating units – Over 51% of the fuel mix is coal
PJM	– 13 states and the District of Columbia – 164,260 square miles	– 56,250 miles	– 144,644 MW	– 1,082 units – Over 56% of the fuel mix is coal
NYISO	– 1 state – 47,225 sq.	10,775 miles of transmission	– Summer 33,939 MW	290 Active units* broken

	miles	lines –		down as follows: 126 Units NG - Natural Gas 51 Units BIT - Anthracite Coal/Bituminous Coal 34 Units RFO - Residual Fuel Oil 28 Units DFO - Distillate Fuel Oil 26 Units WH - Waste Heat 7 Units KER - Kerosene *18 are classified as NEW – neither MW nor fuel type are indicated for these –
CAISO	1 state, 122,780 square miles –	approx 25,525miles of transmission lines	– Summer 50,270 MW	– 1,516 generating units 35 percent is natural gas 19 percent large hydro 17 percent nuclear 16 percent coal 12 percent eligible renewables –

Market Characteristics				
	Energy Market	*Transmission Rights*	*Ancillary Services*	*Resource Adequacy*
ISO-NE	Day Ahead and Real Time	Established Financial	Forward Reserve and Regulating Reserve	Zonal Capacity Obligations
SPP	Real Time	Physical	None	None
MISO	Day Ahead and Real Time	Evolving Financial	None	None
PJM	Day Ahead and Real Time	Established Financial	Regulation and Spinning Reserves	Installed Capacity
NYISO	Day Ahead and Real Time	Established Financial		Installed Capacity
CAISO	Day Ahead and Real time	Physical Evolving Financial	AGC Regulation Spinning Reserves Non-spinning Reserves Replacement Reserve	In the process of developing

Interesting comparisons can be drawn from the above information:

1.) Regional size, e.g., MISO is five times larger than ISO-NE with each of its three sub-regions being larger than ISO-NE itself; NYISO and New England are similar in size

2.) System topography, with varying degrees of integration e.g., NE has one integrated system and SPP, PJM and MISO have multiple "hubs"

3.) Planning experience and history, e.g., NE has had the same footprint for 30 years. NYISO also has not had a changing footprint and SPP and MISO less than 5 years each. PJM's recent expansion has completely redefined its focus and size.

4.) Fuel diversity e.g., NE's generating fleet is highly dependent on gas as a fuel whereas PJM has significant coal-fired resources. New York's system is predominantly gas, although it has some coal units as well.

5.) Competitive market structure, e.g., NE, NY and PJM have a mature SMD market. SPP has the least, without market products for capacity or ancillary services and without a day ahead energy market.

6.) Decisional roles of ISOs, states and transmission, e.g., NE has no RSC, but NECPUC could serve the same function as an RSC in developing a cost allocation methodology. The TOs have a moratorium until 2010 on filing a new proposal under section 205 (although any party may file a new proposal under section 206).

V. COST ALLOCATION METHODOLOGIES IN OTHER REGIONS

In recent years, FERC has approved cost allocation methodologies for the regions discussed above. These regions include New York, PJM, MISO, Southwest Power Pool and California. These cost allocation methodologies are in various stages of development. The cost allocation methodologies for these regions are discussed below

A. Southwest Power Pool

1. State Role in Development of Alternatives

The transmission cost allocation proposal was developed by the regional state committee and adopted by the SPP.

2. Definition and Cost Allocation for Reliability Upgrades

Reliability upgrades are called Base Plan upgrades. Base Plan Upgrades are defined as follows:

> Those upgrades included in and constructed pursuant to the SPP Transmission Expansion Plan in order to ensure the reliability of the Transmission System. Base Plan Upgrades shall also include those upgrades required for new or changed Designated Resources to the extent allowed for in Attachment J to this Tariff.

For Base Plan Upgrades the costs are allocated as follows:

> If the cost of a Base Plan upgrade is less than or equal to $100,000, the annual transmission revenue requirement associated with such upgrade is allocated to the zone in which the upgrade is located. If the cost of the upgrade is greater than $100,000, one-third of the revenue requirement for the upgrade is allocated to the region on a postage stamp basis. The remaining two-thirds will be allocated locally to zones based on each zone's share of the incremental MW-mile benefits as computed in section 4 of Attachment S.

FERC discussed SPP's explanation of how it arrived at the one-third two thirds allocation as follows:

SPP states that it applied its MW-mile method to determine the use of facilities regionally and locally. According to SPP, that study showed that about two-thirds of the usage serves local native load customers with the remainder used regionally. Thus, SPP and the RSC determined that the remaining one-third of new upgrades would benefit the entire region and that those costs should be allocated to the entire SPP.

Southwest Power Pool, 111 FERC 61,118 (2005) P.26. In accepting the proposal, FERC stated:

> We will accept the one-third/two-third cost allocation without modification. While certain parties question whether the regional allocation is consistent with cost causation principles or provide tangible benefits, we find that the proposal is supported by the RSC Cost Allocation Working Group (CAWG) determinations that most transmission facilities provide both a local and regional benefit. SPP

> states that the CAWG performed multiple analyses and found that the MW-mile allocation summation for all zones showed that the total SPP system usage was 66 percent zonal to service native load. This means, according to SPP, that one-third of the transmission system usage reflects regional needs and, therefore, it would be appropriate to use that one-third figure as the regional allocation factor. We agree that this is a reasonable approach to evaluate usage and to assign corresponding costs and will therefore accept the one-third/two-third cost allocation.

Id., P.31 (citations omitted). FERC also found that the proposal was a "reasonable approach to funding needed investments, while eliminating the burden of case-by-case determinations of the regional/local cost allocation." *Id.,* P.34

The tariff provision describing the Megawatt-Mile model states:

> The megawatt mile technique is a distance based impact method of assessing transmission use and topology recognizing that power will, to some extent, flow over all available paths from the generating source to the load. Attachment S § 1.
>
> The incremental MW mile is determined by building the base case with all Base Plan Upgrades in Service. A MW-mile calculation is performed by measuring the flows on each line multiplied by the distance described in section 3.2. The net change of the MW-mile impacts is used for this calculation. Then a benefit determination calculation is made with each new transmission upgrade removed individually. The reduction in MW-mile impact due to each new transmission upgrade is the measure of its zonal benefit.

SPP OATT, Attachment S.

3. Definition and Cost Allocation of Economic Upgrades

Economic Upgrades are defined as follows:

> "Elective upgrades, identified in the SPP Transmission Expansion Plan, which have potential economic benefits to the SPP Region, but are not required for reliability reasons."

SPP OATT, section 1.10a. Under the SPP cost allocation methodology, the costs of an economic upgrade, if constructed, will be allocated in accordance with agreements reached with project sponsors. *Southwest Power Pool, Inc.* 111 FERC ¶61.118 at P. 62.

4. Transmission Investments

The Southwest Power Pool recently published its $1.4 billion, 10-year transmission expansion plan. The list included 1392 miles of new lines, 80 new or upgraded transformers and upgrades or reconstruction on1.058 miles of existing lines.

5. Pros and Cons of Southwest Power Pool transmission cost allocation

Table 3: Pros of Southwest Power Pool Transmission Cost Allocation
(Note: This table identifies a comprehensive listing prepared by staff from each state.)

	CT	MA	ME	NH	RI	VT
Allocating a portion of the costs regionally helps to address concerns that beneficiaries change over time and that there may be some reliability benefit to the grid of individual transmission projects that have more quantifiable economic benefits to specific areas.	✓		✓	✓	✓	✓
The megawatt-mile formula provides an objective formula to determine beneficiaries of projects which should avoid or reduce litigation over beneficiary determination.			✓	✓		✓
The megawatt mile test is a snap shot in time only, it does not reflect how megawatt miles would change over 30 year life as new generators, new transmission, and dispatch order changes.	✓					
The cost disincentives for siting transmission in resource states are lower than if the entire cost of the project were rolled in.			✓	✓		
Methodology appears to be consistent with Order 890 cost causation and assignment of costs to beneficiaries principles			✓	✓		✓

Table 4: Cons of Southwest Power Pool Transmission Cost Allocation
(Note: This table identifies a comprehensive listing prepared by staff from each state.)

	CT	MA	ME	NH	RI	VT
No formula for allocating the costs of economic upgrades.	✓		✓	✓	✓	✓
Immature energy market structure exists in SPP, making the application of SPP practices potentially inappropriate for ISO-NE's more advanced markets.	✓					
Immature energy market structure exists in SPP, which calls into question whether the application of SPP practices is appropriate for ISO-NE.					✓	✓
The megawatt mile test is a snap shot in time only, it does not reflect how megawatt miles would change over 30 year life as new generators, new transmission, and dispatch order changes.	✓	✓			✓	✓
Integrated transmission planning is less developed than ISO-NE. Only two regional plans have been written.	✓					
The 2/3 – 1/3 allocation split that allocates one third of the costs across the SPP footprint and two-thirds to the zones that benefit from a particular project reflects a negotiated allocation among the participants rather than a critical analysis of actual beneficiaries of transmission costs.		✓				
Requires case-by-case analysis of beneficiaries that can lead to increased risk of litigation and uncertainty.		✓				
Does not provide ease of administration or transparency of allocation results.		✓				
Too large a portion of costs are allocated to the whole region			✓	✓		✓

B. Midwest ISO (MISO)

The MISO cost allocation, like the SPP cost allocation methodology, is a hybrid model in that a portion of the costs of certain transmission projects are recovered regionally, while a larger share is allocated to one or more sub regions based on a load flow determination.

1. State Role In The Development Of The Methodology

As in the SPP, the MISO state commission's organization, the Organization of MISO (OMS) states played a critical role in developing the cost allocation methodology.

OMS developed several principles to guide the cost allocation methodology:

- The cost allocation policy should be designed so that MISO can satisfy the requirements of FERC's Order 2003.
- The cost allocation policy should send appropriate signals to generators to efficiently locate their plants on the grid.
- The cost allocation policy should reflect the classic principles of "cost causers should be cost bearers" and "he who benefits should pay."
- The cost allocation policy's inherent incentives or disincentives to construct network improvements should be made transparent.
- The cost allocation policy should be designed to work well within MISO's set of general network facility upgrade cost allocation policies (e.g., reliability, load growth or congestion relief driven).

- The cost allocation policy should not unnecessarily conflict with the various transmission company business models (e.g., vertically integrated, stand-alone affiliated, independent, or merchant) employed within MISO's footprint.

2. Reliability Upgrades

Under the MISO's cost allocation methodology, costs for Baseline Reliability Projects, rated at 345 kV or above are allocated as follows:

- 20% allocated on a postage stamp basis (allocated to the entire region) on a load ratio share basis and 80 percent is allocated sub regionally to all transmission customers in the designated pricing zones affected by the project.
- Baseline reliability projects that are rated 100kV to 344 kV, 100 % of the costs would be allocated sub-regionally to all Transmission Customers in the designated pricing zones.
- The designated pricing zones for the sub-regional cost allocation component are determined on a case-by-case basis in accordance with a Line Outage distribution Factor (LODF) analysis. The percentage of sub-regional allocation to each zone is based on the relative share between pricing zones of the sum of the absolute value of the product of the LODF on each Branch Facility in a pricing zone and the length in transmission line miles of the Branch Facility. A Branch Facility is a facility located within a pricing zone having a defined LODF.
- In order for a baseline reliability project to be part of the regional transmission plan, it must have a project cost of $5 million or more.[29]

[29] See, *Midwest Independent System Operator*, 117 FERC ¶ 61, 208 (2006) (Order on Rehearing and Clarification), *Midwest Independent System Operator*, 117 FERC ¶ 61,241 (2006).

3. Economic Upgrades

On March 15, 2007 FERC issued an Order conditionally accepting MISO tariff revisions. This order was specifically focused on the cost allocation of Economic Upgrades in MISO, called Regionally Beneficial Upgrades. The following discussion from a MISO affidavit attached to the MISO filing regarding the objectives and considerations that went into the stakeholder process to arrive at a cost allocation methodology provides a good summary of some of the issues that are likely to face any cost allocation effort:

> The Midwest lSO's objective at the outset of the RECB cost allocation deliberations was to develop a cost sharing policy that aligns cost allocations with the anticipated beneficiaries of a transmission expansion. An obvious challenge to meeting this objective is the ability to forecast with precision the actual beneficiaries of a Network Upgrade over the long-term life of the transmission facility investments.
>
> The Midwest ISO's goal has been to develop a cost allocation policy with its stakeholders in which it is clear that the customers who will benefit from an investment will pay for that investment. The Midwest ISO recognizes the real difficulties of attempting to assess benefits for a 40-year investment based upon planners' inability to forecast with precision which customers will benefit. Moreover, the Midwest ISO understands that it is probable that the customers that will actually benefit from the transmission expansion will change over time.
>
> In order to ensure that the beneficiaries of a Network Upgrade are proportionately and equitably allocated the costs of transmission improvements, it is necessary to develop a targeted analysis of who those beneficiaries will be throughout the life of the investment. Uncertainty of shifting beneficiaries argues for more generalized cost allocations to reflect these anticipated changes in beneficiaries via a postage stamp type rate process. Load ratio allocations across the entire Midwest ISO cannot provide certainty, however, that all the customers that pay for a transmission facility will necessarily benefit from a specific Network Upgrade.
>
> To address these equity concerns, the Midwest ISO worked with its

> stakeholders to develop a hybrid approach that allocates some cost to the entire footprint and some costs to each of the three sub-regions in the Midwest ISO Region.

Jeffrey Webb Affidavit, ¶¶ 9-12 attached to MISO Compliance Filing dated November 1, 2006 in Docket No. ER06-18.

The cost allocation for economic projects has the following features:

- MISO will allocate 20% of the cost of Regionally Beneficial Upgrades to all transmission customers in the MISO footprint on a load-ratio share basis.
- A "weighted gain-no loss" approach is used to protect customers in a geographic sub-region from being allocated cost when they may not benefit from the upgrade. If the calculated benefits to a particular sub-region, in terms of either production cost benefit or LMP energy cost benefit, are negative, then that sub-region will not be allocated any of the sub-regional share of the costs.
- FERC left open the question of whether Midwest ISO could justify, on a different record, a greater percentage of costs allocated region-wide. FERC asked MISO to provide yearly reviews of the methodology and percentage allocations and to continue to explore refinements to their cost allocation methodology.
- Projects must be 345kV or higher and cost more than $5 million in order to qualify as a Regionally Beneficial Upgrade.[30]

4. Transmission Investments

The MISO transmission planning report for 2006 (MTEP)[31] indicates that numerous transmission projects are getting built. The report states:

[30] *See, Midwest Independent System Operator,* 118 FERC ¶ 61,209 (2007) (Order Conditionally Accepting Tariff Revisions) (Order addresses economic upgrades).

MTEP 06 has identified 416 projects comprised of 738 planned or proposed facility additions or enhancements representing an investment of $3.6 billion through 2011.

. . .

The recommended expansions, together with prior MTEP projects provide for a reliable system for the 2011 timeframe, and address many of the most binding constraints from the first year of market operations. A robust value-driven planning process is in development with the assistance of the Planning Advisory committee that will provide the mechanism to implement additional market efficiency expansion plans eligible for regional cost sharing when related tariff revisions filed on November 1, 2006 are approved by the FERC.

. . .

The $3.6 billion in expansion plans are in addition to the $13 billion in existing transmission investment within the Midwest ISO, and represent a $1 billion increase in identified investment since the prior plan was issued in June 2005. The Midwest ISO projects that the annual cost of about $500 million in transmission cost that these expansions represent will result in avoided market-wide generation production costs of over $2.0 billion annually as compared to generation costs without the expansions.

For the first time, the Midwest ISO tariff will allocate cost between Transmission Owners on a formula basis that will result in a closer match between who benefits and who pays for these investments. Approximately $770 million of the committed investment will be cost-shared in this manner. Roll out of cost allocations was completed during three open stakeholder meetings conducted in January 2007. [32]

5. Pros and Cons of this methodology[33]

[31] The MTEP can be viewed at the following link http://www.midwestiso.org/publish/Document/27851_11011a2ccaa_-7d000a48324a/MTEP06_Report_020507.pdf?action=download&_property=Attachment.

[32] *Id.* at PP. 1-2.

Table 5: Pros of Midwest ISO (MISO) Transmission Cost Allocation
(Note: This table identifies a comprehensive listing prepared by staff from each state.)

	CT	MA	ME	NH	RI	VT
Allocates a portion (currently 20%) of all 345kV and above transmission project costs over a region 5 to 10 times the size of ISO-NE.	✓				✓	
Allocates a limited portion (currently 20%) of all 345kV and above transmission project costs region-wide.			✓	✓		✓
Appropriately takes into consideration that MISO is an extremely large geographic region (e.g., 13 times larger than New England) in which the costs of a transmission project in one sub-region may not benefit another geographically remote sub-region.		✓				
Moves MISO in the direction of greater cost allocation on a regional basis given the fact that prior to MISO formation no regional allocation of transmission project costs occurred.	✓				✓	
Hybrid approach, which allows 20% of costs to be rolled. in addresses concerns (1) that a method should consider indirect benefits to the region and (2) that beneficiaries may change over time.			✓	✓	✓	✓
The methodology was seen for the most part by the MISO states as consistent with the principles established by OMS.			✓	✓	✓	✓
The methodology is consistent with the order 890 principle of regional flexibility based on regional history, market structure, and practices.	✓				✓	
Methodology appears to be consistent with Order 890 cost causation and assignment of costs to beneficiaries principles			✓	✓		✓
	CT	MA	ME	NH	RI	VT

[33] The following tables set forth the views of the NECPUC staff state-by-state of the pros and cons of the ISO-NE methodology.

20/80 split based on studies provided by MISO "which suggest a range for a postage stamp cost allocation between 20 and 30 percent and the 'compromise' proposal adopts the low end of that range." 118 FERC ¶ 61.208 P. 16			✓			

Establishes a clear methodology for cost allocation of Regionally Beneficial Upgrades (economic projects). These costs are socialized across large sub-regions which are larger than all of ISO-NE.	✓				✓	
Establishes a clear methodology for cost allocation of Regionally Beneficial Upgrades (economic projects).			✓	✓		✓
Provides less risk of litigation than an approach seeking to identify specific beneficiaries for each new transmission project.		✓				
Establishes an objective formula for determining beneficiaries. There does not appear to be any litigation over the beneficiary determination			✓	✓		✓
Lower percentage of regionalized costs (than SPP) may reduce disincentives to siting transmission.			✓	✓		✓
Method has been cited by FERC in its recent PJM order as a reasonable hybrid methodology.			✓	✓		✓

Table 6: Cons of Midwest ISO (MISO) Transmission Cost Allocation

	CT	MA	ME	NH	RI	VT
Allocation of costs at the sub-regional level (80% level) is quite different for the Baseline Reliability Projects and the Regionally Beneficial Upgrades. The sub-regional cost allocation of Baseline Reliability Projects is done at a very micro level. However, the sub-regional cost allocation of Regionally Beneficial Upgrades is done at a macro level.	✓				✓	✓
FERC does not view the exact allocation percentages and other allocation parameters to be final and has asked MISO to continue to explore refinements to their cost allocation methodology. FERC has requested yearly reviews of the methodology and percentage allocations. FERC also stated that it would support socialization of higher percentages if the record was adequate.	✓				✓	
The partial regionalization of costs was limited to 345 kV facilities. FERC approved this threshold but also approved the lower kV level for SPP. Query which level would make more sense for New England.	✓		✓	✓	✓	✓
The 80/20 allocation of costs between the three sub-regions and the larger ISO region reflects a negotiated allocation among the participants rather than a critical analysis of actual beneficiaries of transmission costs.		✓				
Does not reflect an analysis of how beneficiaries change over time.		✓				
There were some disputes about how the excluded project list was developed.			✓			
MISO regional allocation percentage too low.	✓					
Load flow based allocation reflects only one of the many reliability measurement techniques of system conditions thus it does not take into account all the system benefits.	✓					
Does not address funding for transmission needed for renewable generation that is location constrained.				✓		

C. PJM[34]

1. Methodology Development Process

On April 19, 2007, FERC issued an order[35] that addresses cost allocation rules for existing and new transmission facilities in the PJM region. For new, centrally-planned transmission facilities, FERC agreed with the use of a "postage stamp" rate for "backbone" facilities at 500kV and above, and also set for hearing the development of the "beneficiaries pays" methodology to allocate costs of new transmission facilities for reliability and economic projects under 500kV.

Key points from the FERC's PJM cost allocation Order include recommendations that PJM's cost allocation methodology should:

- provide regulatory certainty for investors.
- encourage the development of facilities that provide broad, regional benefits.
- Encourage the development of a robust transmission grid.
- not impose large cost shifts among transmission systems for existing facilities.
- provide that beneficiaries of new transmission projects in PJM should pay for the costs of those projects.[36]

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[34] PJM was added to the study later in the process; There was not sufficient time for staff to address pros and cons or gather information about transmission investments for PJM. However, at the Commissioners' direction, NECPUC staff will supplement this report with the additional information from PJM.

[35] *PJM Interconnection, LLC*, 119 FERC ¶ 61,063 (2007).

[36] FERC stated:

> We continue to support PJM's "beneficiary pays" approach of allocating the costs of new, PJM-planned transmission facilities. Under this beneficiary pays' approach, direct beneficiaries of a particular transmission upgrade are identified and directly allocated the costs of that upgrade. We find that, by allocating costs according to these benefits—benefits that flow from these investment decisions—we promote the development of optimal electricity infrastructure.

Id. P.69.

- contain the methodology for allocating costs to beneficiaries in the tariff and this methodology should be applied consistently so that the assumptions and criteria for cost allocation are not relitigated each time a new project is approved by PJM.

FERC also recognized that it would be possible to allocate the cost of 500kV and above facilities through a more discrete modeling methodology, such as the one set for hearing but that allocating some or all of the costs of the highest voltage facilities on a postage stamp basis is reasonable given the difficulty of computer models to capture all economic, reliability and environmental benefits that may be produced over the useful life of a given transmission project and identified MISO, SPP, ISO-NE and California methodologies as different but reasonable ways to address this concern.

2. Definition of Reliability and Economic Upgrades

PJM divides transmission expansions into two categories: reliability and economic. Reliability expansions are those needed to ensure that load can be met reliably. Economic expansions (also called “market efficiency” expansions) are those that will reduce the costs of meeting load but are not needed to meet load reliably. *PJM Interconnection*, 119 FERC 61,265 (2007) n. 2. In a recent order, FERC rejected a compliance filing by PJM that used seven congestion metrics to determine the benefits of a possible economic upgrade. Based on an evaluation of all of these metrics, and the input of stakeholders, PJM would determine whether to recommend that an upgrade be included in the RTEP as an economic upgrade. FERC rejected the filing stating,

> In its compliance filing, PJM has not provided any discernible method by which it plans to weigh, consider and/or combine the various metrics it proposes for determining the net economic benefits of a project. If the metrics for determining whether projects qualify as economic projects remain vague and are not in PJM's tariff, the parties opposing a project (or the cost allocation that will result from the project) could contest PJM's assumptions and analysis. A consequence of this is greater uncertainty that could adversely affect decisions by private investors.

Id. P. 30. Accordingly FERC directed that PJM

> file a formulaic approach to choosing economic projects proposed to reduce congestion that describes exactly how any metrics will be calculated, weighed, considered and combined.[37] One example of such an approach is the Midwest Independent Transmission System Operator, Inc.'s so-called "weighted gain-no loss metric," which calculates the anticipated annual benefits of a proposed project to customers using two present value metrics: (1) the production cost benefit (weighted at 70 percent); and (2) the locational marginal price energy cost benefit (weighted at 30 percent).[38] PJM is, of course, free to develop its own formula and to determine which metrics will apply, but the result should be that projects satisfying the "bright-line" formula will be presumptively included in the RTEP.

Id. P.31.

D. NYISO

1. State Role in Development of NYISO Methodology

The New York Public Service Commission actively participated in the development of the planning and cost allocation proposal filed by NYISO in 2004 and filed comments in support of the proposal. *New York Independent System Operator, Inc.* 109 FERC ¶ 61,372 (2004)

2. Description of Methodology

The NYISO contains the following FERC approved principles for cost allocation of reliability upgrades:

> Cost allocation for regulated solutions to Reliability Needs shall be determined by the NYISO based upon the principle that beneficiaries should bear the cost responsibility. The NYISO will develop criteria in consultation with Market Participants for determining the beneficiaries of regulated solutions to Reliability Needs. The specific cost allocation methodology, to be developed by the NYISO in consultation with the ESPWG, will incorporate the following elements:

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[37] For instance, PJM should list in its Tariff the general categories of costs that will be included in the total production cost metric.

[38] *Midwest Independent Transmission System Operator, Inc.*, 118 FERC ¶ 61,209, at P 5-9 (2007).

> a. The focus of the cost allocation methodology shall be on solutions to violations of specific Reliability Criteria.
>
> b. Potential impacts unrelated to addressing the Reliability Needs shall not be considered for the purpose of cost allocation for regulated solutions.
>
> c. Primary beneficiaries shall initially be those Transmission Districts identified as contributing to the reliability violation.
>
> d. The cost allocation among primary beneficiaries shall be based upon their relative contribution to the need for the regulated solution.
>
> e. The NYISO will examine the development of specific cost allocation rules based on the nature of the reliability violation (e.g., thermal overload, voltage, stability, resource adequacy and short circuit).
>
> f. Cost allocation among Transmission Districts shall recognize the terms of prior agreements among the Transmission Owners, if applicable.
>
> g. Consideration should be given to the use of a materiality threshold for cost.
> allocation purposes.
>
> h. The methodology shall provide for ease of implementation and administration to minimize debate and delays to the extent possible.
>
> i. Consideration should be given to the "free rider" issue as appropriate. The methodology shall be fair and equitable.
>
> j. The methodology shall provide cost recovery certainty to investors to the extent possible.
>
> k. The methodology shall apply, to the extent possible, to Gap Solutions.
> 10.3 Interconnection Cost Allocation

NYISO OATT Attachment Y §10.

The NYPSC, the NYISO and stakeholders are continuing to develop the methodology for implementing these principles. The NYISO plans to submit the methodology to implement these principles as part of its Order 890 compliance filing in September 2007.

On December 28, 2004, the Commission accepted the NYISO's transmission planning methodology in which the cost allocation methodology was not fully developed. NYISO stated that there was a strong consensus for a "beneficiaries pay" approach which was supported by the NY commission. This "beneficiaries pay" methodology is still under development at NYISO. The planning process does not mandate solutions for economic needs.

3. Pros and Cons of NYISO Methodology

Table 7: Pros of NYISO Transmission Cost Allocation

(Note: Due to exigencies of time MA, RI and CT did not provide pros and cons for NYISO.)

	CT	MA	ME	NH	RI	VT
The allocation method was developed with approval from the siting state.			✓	✓		✓
The methodology will be developed so that it can be objectively applied without extensive litigation.			✓	✓		✓
The disincentive to siting transmission in one area to relieve a reliability problem in another area will not be as great as if the costs of the upgrade were allocated in part to the area which did not cause the need for the upgrade.			✓	✓		✓
There is less disincentive for siting economic projects in "resource" areas because a proposal for an economic upgrade may have to incorporate incentives for the resource area in order to win approval.			✓	✓		✓
Provides better signals for siting generation where it is needed than if costs are spread regionally.			✓	✓		✓
Methodology appears to be consistent with Order 890 cost causation and assignment of costs to beneficiaries principles			✓	✓		✓

Table 8: Cons of NYISO Transmission Cost Allocation
(Note: Due to exigencies of time MA, RI and CT did not provide pros and cons for NYISO.)

	CT	MA	ME	NH	RI	VT
Does not allocate any portion of the costs regionally, so may not address concerns about how to address shifting beneficiaries over time.			✓	✓		✓
Does not have a specific formula for allocating costs of economic upgrades.			✓	✓		✓
Does not address funding for transmission needed for renewable generation that is location constrained.						

E. CAISO

Prior to 2000, there were three separate transmission zone rates in the California ISO ("CAISO") based on the revenue requirement of the Participating Transmission Owner in each zone. On May 31, 2000, FERC accepted for filing a new tariff that moves CAISO to a single high voltage ISO grid-wide Transmission Access Charge ("TAC") over a ten-year transition period. According to FERC, "[t]his evolution in rate design away from the utility-specific zone rates to a high voltage grid-wide methodology ensures a uniform grid-wide rate." *California Independent System Operator Corporation* 91 FERC ¶ 61,205, at 61,722 (May 31, 2000).

High voltage includes transmission that is 200 kV or higher. The transmission revenue requirement for transmission facilities below 200 kV is recovered through a separate local transmission access charge on a utility-specific basis. The transition period is now in its fifth year. *See*, *California Independent System Operator Corporation* 91 FERC ¶ 61,205 (May 31, 2000); *California Independent System Operator Corporation* 105 FERC ¶ 63,008 (July 2003); *California Independent System*

Operator Corporation, 109 FERC ¶ 61,301 (December 21, 2004); Order Denying Rehearing and Granting Clarification, 111 FERC ¶ 61,337 (June 2, 2005).

CAISO has also addressed related aspects of cost allocation such as the cost allocation of generator interconnection upgrades. *See, e.g. California Independent System Operator Corporation*, 119 FERC ¶ 61,061 (2007).

1. Pros and Cons of CAISO Methodology[39]

Table 9: Pros of CAISO Transmission Cost Allocation

	CT	**MA**	**ME**	**NH**	**RI**	**VT**
Method is objective.			✓			✓
Method was developed with the approval of the siting state.			✓			✓
Filing that was recently approved by FERC provides a method for funding transmission needed to support location-constrained renewable generation.				✓		

[39]Due to the exigencies of time MA, NH, and RI did not provide pros and cons for the CAISO methodology)

Table 10: Cons of CAISO Transmission Cost Allocation

	CT	MA	ME	NH	RI	VT
Areas that do not benefit from the upgrade will likely see this allocation as inequitable			✓	✓		✓
Does not send the proper signals for siting generation where it is needed most.			✓	✓		✓
May result in uneconomic transmission being constructed if it is less costly to one sub area to pay only a share of transmission than to pay the costs of generation or demand response needed for reliability in a load pocket, but more costly over all to build the transmission.			✓	✓		✓
Consideration of high voltage (200 kV) as criteria for regionalization does not take into account the actual benefits that an upgrade may provide to one sub-area or costs that it may impose on another.			✓			✓
May not be consistent with Order 890 cost causation and assignment of costs to beneficiaries principles			✓			✓

VI. OTHER CONSIDERATIONS

A. Beneficiary Evaluation

In evaluating the beneficiaries of a transmission project, some states have suggested that a "beneficiaries analysis" might extend beyond increased reliability to consideration of the potential for secondary benefits such as increased economic development, jobs, property taxes, and new generation business opportunities that may occur as a result of siting new transmission.

Some believe that one way to deal with possible difficult to quantify benefits is to allocate a portion of the total transmission costs regionally (leaving a portion to be paid by one or more sub-regions) as is done in hybrid models such as MISO and SPP. One point is clear from FERC cases, however. FERC does not want a case by case beneficiary analysis that is subject to litigation. Thus to the extent possible benefits such as those discussed above are considered in cost allocation, they must be built into whatever formula or methodology is approved in advance and set forth in the tariff. *See*, *PJM Interconnection*, 119 FERC ¶ 61,063 P.4. Another consideration is whether the types of benefits listed above are sufficient to provide incentives for siting transmission in resource states and whether these are considerations that a state commission can take into account in determining whether a transmission line is in the public interest. If these are relevant considerations for a state certification process, another question is whether such benefits are sufficient to outweigh the increased energy and transmission costs to the ratepayers of the resource state.

B. Role of the Planning Process

Another aspect of the policy considerations directly associated with cost allocation is the interrelationship between the regional planning process and state support for various cost allocation methodologies. Vermont would ask the states in the region to consider rethinking the planning process to use regional (ISO) resources to gather information and engage in planning for deployment of **<u>all</u>** resources, not just transmission. This would help the development of alternatives to transmission as the only backstop solution. All lower cost alternatives should be clearly identified in the planning process and detailed plans developed for acquisition of targeted demand resources, including energy efficiency and distributed generation, when such action is clearly less expensive for the region than building more expensive transmission and bringing in remote generation to the load centers. The states should be full participants in this expanded regional planning process. In addition, Vermont asks the other states to consider whether lower cost solutions should be eligible for regional or sub-regional cost recovery. Such an approach would be consistent with Vermont statutes, unlike the planning process we currently have in place today. Asking a state to pay for transmission upgrades that have been identified through a planning process that is inconsistent with state laws makes it very difficult to support any funding mechanism for those upgrades. It also makes siting for transmission more difficult because lower cost alternatives may exist yet states are being asked to pay for a more expensive solution. Thus the planning process cannot be divorced from the cost allocation process.[40]

C. Fuel Diversity

In another related area, some states have suggested that developing a rule change to permit regional cost sharing for the interconnection costs of renewable generators could provide reliability benefits by increasing fuel diversity. Some argue that reliability benefits also may be analyzed more broadly to include the benefits of fuel diversity (e.g., new transmission may allow load centers to obtain improved access to more remote renewable energy supplies), and the associated environmental benefits arising from access to renewable energy supplies (*e.g.*, reduction in emissions).

NECPUC can consider whether both of these issues, (1) planning and possible funding for lower cost alternatives to transmission upgrades, and (2) planning and cost allocation policies that would promote fuel diversity are integral to this

[40] The Commissioners may also benefit from a review of the ISO-NE and NE PTOs joint posting, (5/29/30), of a planning strawman as required under FERC Order 890 requirements. This posting addresses the nine planning principles including cost allocation. NECPUC has not yet formed any position on this filing to date.

discussion and should be further researched and considered by NECPUC as part of this study.

D. Contract for Differences [This section is supported by Maine, NH and RI

Note: Connecticut and Massachusetts do not agree that the Commissioners should consider the CFD issue as part of this study.]

In addition to these transmission cost allocation alternatives listed below, the Commissioners may wish to consider a transition mechanism to address energy cost impacts of building new transmission to provide high load states access to generation resources in low cost resource states. In general, new transmission between resource-long and resource short regions drive up the costs of the market price in the resource long region. On one hand, this makes some sense since the goal is to have a broader market and the increased trading will tend to make costs converge in both the resource rich and load rich areas.[41] Transmission cost reallocation is an important step, but it does not address the impacts on the market electricity prices, including losses and congestion. A limited time (9 year) contract for differences (CFD) is one way to address this disincentive. The CFD would act as a buffer for ratepayers in the resource state between the lower pre-transmission energy and the higher priced energy resulting from the transmission upgrade. Eventually ratepayers in the resource state would pay the higher energy price at the end of the term of the CFD. The two CFD options are as follows:

1. CFD option 1. An estimate is made of what the resource state would have for an energy market price for a period of time, for

[41] Maine and New Hampshire energy rates are consistently below the hub price due to low, often negative loss and congestion charges. We are reasonably certain that the same is true for Rhode Island and at least portions of Massachusetts, although some further analysis on that point is in order.

example the next 9 years, without transmission upgrades. The CFD will then have that estimate as the strike price

2. CFD option 2. Set the CFD based on a discount off the hub price. For example, if the resource state pays 10% less than hub today and expects that to drop to 2% below hub if new transmission is built, the CFD would have the resource state pay 8% less than the hub price for energy.

Connecticut's Views on CFD Option

CT opposes any proposal, such as the proposed CFD mechanism, that would require all of the states in the region to agree to guarantee a certain state or states, where transmission projects are proposed to be built, a fixed energy price for a set period of time in exchange for those states agreeing to site the projects. First, CT views ***energy price mechanisms*** as outside the scope of the resolution which directed NECPUC staff 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."

Second, and more importantly, CT believes that it is bad public policy to link transmission cost allocation with energy market prices and proposals such as the CFD proposal. Transmission projects that have been identified through the regional planning process as needed Reliability Upgrades should be built without any additional compensation (in the manner of fixed lower energy prices subsidized by consumers in other states) to the state or states where the project will need to be built. If a Reliability Upgrade relieves congestion in a state or states where the project was built and this, in turn, raises energy prices in that state or states and lowers prices elsewhere because generators can now sell outside the formerly congested area, this result is a product of the energy market design. Any predicted price impact should not affect whether needed Reliability Upgrades are approved and built. Additionally, CT agrees with the Maine Public Utilities Commission's conclusion in its January 16, 2007 Interim Report[42], at p. 14 that, for various reasons, that there is no entitlement for any set of the region's consumers to a fixed energy price. Specifically, the Maine Commission found:

> The submarket in Maine creates an energy market that is approximately $30 million less expensive each year than the New England hub. However, the value of this "benefit" is eroding rapidly. As Maine's demand for electricity increases each year the submarket benefit is decreasing. Though increased generation is being planned in Maine, which could increase the benefits of the submarket, it would be imprudent for the purposes of this study, for the reasons discussed below, to focus on these energy market attributes as entitlements for Maine ratepayers.
>
> First, generation is locating in Maine to serve regional load, not simply the load of Maine consumers. If Maine were to consider alternatives to ISO-NE, such as creating a Maine "electricity island,"[43] it is likely that much of the investment in generation currently planned for Maine would be chilled. Second, Maine has policies promoting renewable generation,[44] which generation would be greatly discouraged by a regulatory regime that sought to artificially capture generation and lower prices. Finally, as discussed previously, parties are considering several significant transmission projects that would expand the current transmission system in order to remove the constraint and increase the system's capability to export power outside of Maine.
>
> For the foregoing reasons, we have assumed that there is no net cost of energy for Maine associated with the current ISO-NE arrangement. We note, though, that under the *status quo* arrangement, costs for the investments needed to increase Maine's capability to serve load in southern New England would not only result in increased energy costs in Maine, but would also be socialized and, thus, recovered in part

[42] The full title of the Interim Report is Interim Report Pursuant to "A Resolve to the Direct Public Utilities Commission to Examine the Continued Participation by Transmission and Distribution Utilities in this State in the New England Regional Transmission Organization"

[43] *See,* Discussion document entitled, "What if Maine Were an Electricity Island," which can be accessed from the Commission's Virtual Case File.

[44] *See,* P.L. 2005, ch. 677 "An Act to Enhance Maine's Energy Independence and Security."

> from Maine ratepayers. An essential question as part of our analysis going forward will be whether there are alternatives to the *status quo* arrangement which might more equitably allocate such costs to the cost causer or investment beneficiary and, as a result, more accurately price, from an economic perspective, both transmission and generation service.

CT believes that this reasoning is sound and applies to the whole region and does not understand why it is now being abandoned by Maine, as it is now advocating for the purposes of this proposed report, for a fixed energy price in exchange for agreeing to site transmission projects that may be necessary for maintaining the reliability of the NE grid. Finally, CT believes that this CFD proposal is unworkable because it requires ill-advised speculation in the form of forecasting that the energy price in a particular location would remain at a lower price going forward. Energy prices in a particular location could increase as the result of numerous factors besides transmission upgrades such as increased demand, fuel prices and availability, generation unit retirements, outages, etc.

VII. ALTERNATIVES

A. The alternatives listed below are set forth for the Commissioners consideration:

1. Retain existing cost allocation methodology.

2. Develop a hybrid methodology perhaps combining features of the MISO and SPP cost allocation methodologies, both of which allocate a portion of the costs regionally and a portion to beneficiaries based on an objective load flow methodology.

3. Develop a hybrid methodology discussed above combined perhaps with some aspects of the California renewable interconnection approach,

4. Develop a hybrid approach that blends a decision on cost allocation methodology with reform of the planning process to promote more efficient use for all resources, including funding options for least cost alternatives.

B. Connecticut's Views on Alternatives

The vast majority of stakeholders agreed in NE that the appropriate cost allocation methodology for the region at that time should allocate the costs of transmission upgrades that are necessary to ensure the continued reliability of the system to the New England region, as all regional stakeholders benefit from system reliability. It was also agreed by the majority of stakeholders that the costs of transmission upgrades that provide only local benefits, such as generator interconnections, merchant transmission, are to be paid for by the local beneficiaries of the local upgrade. Thus, under the current methodology, projects that do not provide system-wide benefits are not afforded regional cost support.

NEPOOL and ISO-NE and the Maine and Rhode Island coalition each made cost allocation filings with the FERC. FERC approved the NEOOL and ISO-NE methodology and rejected the same Maine and Rhode Island proposal that had been rejected earlier by NEPOOL.

Under the current methodology, only two types of upgrades qualify as Regional Benefit Upgrades (RBUs) to receive cost recovery through regional rates. To qualify as an RBU, a project must be included in ISO-NE's Regional System Plan (RSP) as either a Reliability Transmission Upgrade (RTU) or a Market Efficiency Transmission Upgrade (METU). RTUs provide system-wide benefit to ensure that the entire New England region meets established reliability criteria and that uninterrupted service continues to be provided throughout the region. METUs may also qualify as RBUs if the METUs are designed to provide network-wide benefits that reduce bulk power system costs to load system-wide. All other transmission projects are paid for by the interconnecting generator or the local beneficiaries.

The cost allocation methodology set forth in the ISO-NE OATT has been in place since December 2003. Since that time, the region's transmission owners have constructed a number of major transmission lines that were deemed to be needed to ensure the reliability of the New England transmission system. At this time, approximately $5 billion in new transmission investment is planned or has been made in the last seven years. Examples of recent regional reliability upgrades receiving regional cost support include Connecticut's 345kV transmission loop and Maine's Northeast Reliability Interconnection project.

CT believes that a review of other ISO/RTO markets has shown that New England's, small and stable geographic size, long history of tight power pool planning, established topography and backbone, advanced market design and rules along with limited fuel diversity, make it a unique market. CT believes that different cost allocation methods are appropriate in regional markets. NE itself has seen its own cost allocation method change as its market rules, planning process and governance changed. As recently as 1997 NE fundamentally shifted from a transmission cost allocation structure that was "license plate" based to a "postage stamp" design, negotiated with an extensive transition period which is just now ending, 10 + years later.

CT believes that the current FERC-approved NE cost allocation methodology is successful in incenting transmission investments that are largely focused on reliability improvements, planned by an independent function (ISO-NE) and secondary to market based solutions. The current cost allocation method allows for cost to be allocated locally and regionally and allows stakeholder input and review. The current NE structure fairly and effectively matches costs with beneficiaries and has the support of its market participants, ISO-NE and PTOs. Consistent with FERC's order 890 at paragraph 558, CT believes the current NE cost allocation method works well and should not be revisited. If alternatives are to be considered, the current methodology should remain in place until least 2010 the currently FERC approved moratorium expires. NE's current planning process, market structure, underlying transmission system and tariff (including cost allocation) collectively are working well together. NE is using a planning process that is highly consistent with the principles FERC has established in Order 890 and has resulted in a robust regional plan, focused on system reliability but open to economic opportunities. NE is building transmission based on this plan as a back stop to market initiatives. NE has an established cost allocation process that has been reviewed and approved by FERC and supported by approximately 78% of NEPOOL Participants, ISO-NE and the majority of Transmission Owners. Indeed, ISO-NE and the Participating Transmission Owners have just stated in their order 890 strawman posting that *"This process (cost allocation) also is consistent with the three factors Order No. 890 states the Commission will consider when evaluating a cost allocation dispute."*[45]

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[45] Relative to cost allocation the NE strawman posting states:

Planning Principle #9: Cost Allocation

- ***Requirements***

This report should support the FERC position that regional variations are appropriate. This report should also recommend that the cost allocation process in NE remain unchanged until evidence can be found that it fails to incent transmission investment or that the matching of costs and benefits fail to meet the requirements of Order 890.

To the extent that this report seeks to examine how various regions provide incentives to build transmission in areas with generating resources, and how beneficiaries of transmission are defined, CT believes that it is critical to understand that each region is unique with different core characteristics, history and challenges. As such, a simple comparison of cost allocation practices is extremely difficult and perhaps not

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- _ For a planning process to comply it must address the allocation of costs of new facilities. (P 557) _ The Commission emphasizes that it is not modifying the existing mechanisms to allocate costs for projects. (P 557)
- _ The cost allocation principle. . . is intended to apply to projects that do not fit under the existing structure, such as regional projects involving several transmission owners or economic projects that are identified through the [economic] study process described above, rather than through individual requests for service. (P 558)
- *ISO New England's "Strawman" Proposal May 29, 2007*
- *for Regional Transmission Planning* 1 8
- _ Stakeholders and Transmission Providers are permitted to determine their own specific criteria which best fit their own experience and regional needs. (P 558)

Regional System Planning

- Schedule 12 of the ISO-NE OATT, developed in response to Commission Orders in 2002 and 2003 for ISO-NE and NEPOOL to establish a transmission cost allocation process, provides clear rules for the sharing of transmission costs throughout the New England region. Schedule 12 describes the cost allocation treatment of upgrades, modifications or additions to the New England transmission system. Importantly, the PTOs have the Section 205 rights over the methodology by which the costs of upgrades are allocated, pursuant to Section 3.04 of the TOA.
- This process also is consistent with the three factors Order No. 890 states the Commission will consider when evaluating a cost allocation dispute.11 Specifically, Schedule 12 and Schedule 12C allocates the costs for system upgrades that provide a regional benefit across the entire region. Aspects of a project that provide only a localized benefit, however, constitute Localized Costs that may not be included in the Pool Regional Network Service ("RNS") Rate. Section 4.4 of the Northeastern ISO/RTO Planning Coordination Protocol provides that the cost allocation for elements of the NCSP will be addressed consistent with the applicable provisions of each party's tariff.
- ***Planning for Local Transmission Facilities***
- The ISO-NE OATT (and the PTO local service schedules incorporated therein) already contain Commission-approved cost allocation provisions that address allocation of costs for new facilities.

meaningful without further study to determine if differences in regions justify different approaches to cost allocation.

At the outset, CT would like to make some initial observations with respect to the potential applicability of other region's cost allocation methodologies to NE. With respect to MISO, the history of MISO is also quite different than that of ISO-NE. MISO was approved as an RTO in 2001. It established the precedent as being the first multi-state RTO without a historical tight power pool. Without this history they had no basis for the transition to an RTO. Prior to MISO formation, 23 distinct control areas were run by the footprint utilities, each with its own dispatch and tariff. A number of compromises have been agreed to in a robust and lengthy stakeholder process in order to more forward with an Order 2000 compliant RTO and the components of Standard Market Design. The level of industry restructuring also varies widely across MISO. Only 4 out of 15 states and one Canadian province in MISO are restructured for retail access. The other states have regulated utilities that can be ordered to build necessary infrastructure.

CT is also mindful that a key concern of many stakeholders was to ensure a clear demarcation of responsibilities between operators of control areas within the Midwest ISO Region and those tasks that the RTO would perform. This task required implementation of new technology, agreements, and procedures to coordinate the operations of the 23 distinct control areas. Unfortunately on August 14th 2003, the difficulty of these challenges became apparent. MISO did not have sufficient technology and procedures to monitor and manage the resulting cascading blackout which hit six states and the Canadian provinces of Ontario and Quebec, denying power to 60 million people. CT believes that MISO is an RTO which continues to evolve and whose history makes it difficult to compare to New England in a meaningful way.

With respect to use of MISO and SPP "hybrid" cost allocation methodologies in which a portion of the costs are regionalized and a portion are allocated to so-called local beneficiaries based on an objective load flow methodology, CT is concerned the that load flow based allocation methods employed to determine local beneficiaries do not accurately reflect system benefits of transmission upgrades. They are ***one-time*** models of energy flows on the current system. They do not account for the 30 to 40 year life of transmission assets and how the system flows will change with every new or retired generator, with additional transmission upgrades, with growth and shifts in loads, with higher or lower fuel prices impacting generation dispatches, with changing environmental constraints on dispatch or a host of other possible impacts. Load flow based allocations may not fully reflect the value of a transmission upgrade relative to reliability. Reliability studies are based on contingencies (N-1 and possibly N-2). Load flows only consider incremental changes of an upgrade without addressing other reliability measures such as system stability, short-circuit ratings, and interface impacts. Load flow allocations show only a narrow benefit, overlooking the reliability value of an investment which can be realized over a much broader area of the transmission system. Although a load flow methodology has been adopted in some regions as a compromise or settlement for allocating costs, CT believes that it is not a technically superior solution to the NE approach based on the factors discussed above.

One common theme across regions that CT thinks is important is that all of the regions examined share the cost of their backbone transmission facilities on a regional basis. For example, in PJM, a region many times the geographic size of NE, three voltages 765 kV, 500 kV, and 345 kV backbone lines largely are paid for on a regional basis. Applying the principle that the cost of backbone facilities should be shared regionally, CT believes that the PTF assets including 345 kv and 115kV lines are the equivalent to the PJM backbone lines and are, therefore, the backbone of the NE system and should be paid for on a regional basis as is done through the current NE cost allocation method.

VIII. CONCLUSION

This report provides a preliminary examination of the issues set forth in the resolution. NECPUC staff awaits direction from the Commissioners regarding any additional analysis or information they would like from the staff.

Attachment 1

NECPUC JANUARY 8, 2007

RESOLUTION

NECPUC Resolution To Study Alternatives To The Current Transmission Cost Allocation Methodology

WHEREAS, new generation and transmission facilities will be needed in New England; and

WHEREAS, it is conceivable that refinements could be made to the current transmission cost allocation methodology that benefit the region and individual states; and

WHEREAS, all NECPUC members agree that all New England consumers should benefit from pool transmission facility investments, *now therefore be it*

RESOLVED, That NECPUC commits its staff energy 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. The NECPUC energy policy staff will prepare a report by June 1, 2007 for report to NECPUC at the summer NECPUC meeting.

Attachment 2

OCTOBER '06 ISO-NEW ENGLAND Project Listing Update (FINAL)

Part#	Project ID	Primary Equipment Owner	Other Equipment Owner(s)	Projected In-Service Month/Year	Major Project	Project	July 2006 Status	October 2006 Status	Substation ROW	Transmission ROW	I.3.9 Approval	TCA Approval	TCA Category	July 2006 Estimated Costs	October 2006 Estimated Costs
						RELIABILITY PROJECTS									
1a	56	Bangor Hydro-Electric Company	New Brunswick T.C.	Dec-07	Northeast Reliability Interconnection Project	Point Lepreau to Orrington - New 345 kV line as well as capacity expansion from Orrington to Maine Yankee.	Under Construction	Under Construction	No ROW required	New ROW required	Mar-03	May-06	02	$109,900,000	$109,900,000
1a	143	Bangor Hydro-Electric Company		Dec-09	Down East Reliability Improvement	BHE Down East Reliability Improvement	Planned	Planned	New Station; purchase required	New ROW required	May-06	No	02	$25,000,000	$40,000,000
1a	147	Central Maine Power Company		Dec-07		Add 115/34.5 kV transformer at Raymond substation on Section 208/209	Proposed	Planned	No ROW required	No new or expanded ROW required	Jun-06	No	02	$4,800,000	$4,800,000
1a	154 [1]	Central Maine Power Company		Dec-08	Maguire Road Project	Rebuild Louden - Maguire Road 115 kV Line S163.	Proposed	Planned	No ROW required	No new or expanded ROW required	Jun-06	No	02	$1,200,000	$1,200,000
1a	155 [1]	Central Maine Power Company	Northeast Utilities	Dec-08	Maguire Road Project	Rebuild Three Rivers - Quaker Hill 115 kV Line S197.	Proposed	Planned	No ROW required	No new or expanded ROW required	Jun-06	No	02	$3,000,000	$3,000,000
1a	149	Central Maine Power Company		Dec-08	Maguire Road Project	Convert Maguire Road to a switching substation by replacing switches with breakers.	Proposed	Planned	No ROW required	No new or expanded ROW required	Jun-06	No	02	$3,300,000	$3,300,000
1a	715	Central Maine Power Company		Dec-08	Maguire Road Project	**Rebuild South Gorham to Louden 115 kV Line S219.**	Proposed	Planned	No ROW required	No new or expanded ROW required	Jun-06	No	02	TBD	TBD
1a	716	Central Maine Power Company		Dec-08	Maguire Road Project	**Reconductor. South Gorham to Louden 115 kV Line S220**	Proposed	Planned	No ROW required	No new or expanded ROW required	Jun-06	No	02	TBD	TBD
1a	717	Central Maine Power Company		Dec-08	Maguire Road Project	**Install a 115 kV 30 MVAr capacitor bank at Sanford.**	Proposed	Planned	No ROW required	No new or expanded ROW required	Jun-06	No	02	TBD	TBD
1a	59	National Grid, USA		Dec-08	Auburn Reliability	Bridgewater and Auburn Street - Line Terminal 115 kV upgrades.	Planned	Planned	No ROW required	No new or expanded ROW required	Mar-02	Jan-03	02	$400,000	$400,000
1a	75 [2]	National Grid, USA		Sep-06	Central Massachusetts Reinforcements	Reconductor M-39 69 kV Line from Wachusett to Fitch	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Apr-04	Apr-06	02	$2,769,000	$2,769,000
1a	74	National Grid, USA		Oct-06	Central Massachusetts Reinforcements	Wachusett (2) 345/115 kV Autotransformers and 345 kV Station	Under Construction	Under Construction	New Station; own property	No new or expanded ROW required	Apr-04	Apr-06	02	$42,370,000	$42,370,000
1a	78 [3]	National Grid, USA		Dec-06	Central Massachusetts Reinforcements	Reconductor Wachusett - West Boylston (P142N) 115 kV line.	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Apr-04	Apr-06	02	$300,000	$300,000
1a	707	National Grid, USA		Dec-06	Central Massachusetts Reinforcements	W. Boylston Sub upgrade to NPCC Criteria and 115 kV breaker.	Planned	Planned	No ROW required	No new or expanded ROW required	Apr-04	Apr-06	02	$500,000	$500,000
1a	709	National Grid, USA		Dec-06	Central Massachusetts Reinforcements	Wachusett Sub - #47 2nd 115/69 kV transformer.	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Apr-04	Apr-06	02	$2,104,000	$2,104,000
1a	175	National Grid, USA		May-07	Monadnock Area Reliability	Retension Bellows Falls to Ascutney Tap (W-149S) 115 kV line.	Planned	Planned	No ROW required	No new or expanded ROW required	Mar-06	No	02	$7,879,000	$7,575,000
1a	174	National Grid, USA		Jun-09	Monadnock Area Reliability	Reconductor I-135 (Bellows Falls-Monadnock Tap-Flagg Pond) 115 kV line.	Planned	Planned	No ROW required	No new or expanded ROW required	Mar-06	No	02	$12,974,000	$12,974,000
1a	176	Northeast Utilities-NH		2009	Monadnock Area Reliability	Install new Fitzwilliam 345/115-kV substation and 345-kV breakers.	Planned	Planned	New Station; own property	No new or expanded ROW required	Mar-06	No	02	$35,900,000	$54,358,000
1a	177	Northeast Utilities-NH		2009	Monadnock Area Reliability	Replace limiting terminal equipment at Webster Substation on line to North Road.	Planned	Planned	No ROW required	No new or expanded ROW required	Mar-06	No	02	Portion of $35,900,000 (above)	Portion of $54,358,000 (above)
1a	178	Northeast Utilities-NH		2009	Monadnock Area Reliability	Rebuild 115-kV Garvins to Webster V-182 line.	Planned	Planned	No ROW required	No new or expanded ROW required	Mar-06	No	02	Portion of $35,900,000 (above)	Portion of $54,358,000 (above)
1a	179	Northeast Utilities-NH		2009	Monadnock Area Reliability	Rebuild 115-kV Jackman to Greggs F-162 line, or Greggs reactor size increase.	Planned	Planned	No ROW required	New ROW required	Mar-06	No	02	Portion of $35,900,000 (above)	Portion of $54,358,000 (above)
1a	180	Northeast Utilities-NH		2009	Monadnock Area Reliability	Rebuild 115-kV Keene to Swanzey A-152 line.	Planned	Planned	No ROW required	No new or expanded ROW required	Mar-06	No	02	Portion of $35,900,000 (above)	Portion of $54,358,000 (above)

Notes

[1] Project ID #154 and 155 (Maguire Road Project) : Costs are preliminary estimates reported in RTEP02 for ID # 155 and RTEP04 for ID #154. The reported costs for ID # 155 does not include Northeast Utilities estimate.

[2] Project ID 75 (Central Massachusetts Reinforcements): Completed except one section over a reservoir and tap into substation.

[3] Project ID 78 (Central Massachusetts Reinforcements): Line work is complete, but tap into station yet to be done.

Notes
- Gray shading indicates change from JULY '06 Update.
- All costs provided by Transmission Owners.

Part#	Project ID	Primary Equipment Owner	Other Equipment Owner(s)	Projected In-Service Month/Year	Major Project	Project	July 2006 Status	October 2006 Status	Substation ROW	Transmission ROW	I.3.9 Approval	TCA Approval	TCA Category	July 2006 Estimated Costs	October 2006 Estimated Costs
1a	182	Vermont Electric Power Co		2007	Monadnock Area Reliability	Upgrade bus cable at N. Rutland and K32 115 kV breaker at Rutland.	Planned	Planned	No ROW required	No new or expanded ROW required	Mar-06	No	02	$1,000,000	$1,000,000
1a	187	Vermont Electric Power Co		Dec-09	Monadnock Area Reliability	Coolidge +/- 75 MVAr STATCOM with 50 MVArs of new capacitors at Coolidge.	Planned	Planned	No ROW required	No new or expanded ROW required	Mar-06	No	02	$25,000,000	$25,000,000
1a	541	National Grid, USA		May-07	North Shore Upgrades	Ward Hill Substation - new 115/13 kV #2 transformer.	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Oct-05	No	02	$1,866,000	$1,866,000
1a	169	National Grid, USA		Jun-07	Southwest Rhode Island Reliability Enhancements	Reconductor W. Kingston - Kenyon 115 kV 1870N line.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-05	Mar-05	RBU	$2,401,000	**$2,535,000**
1a	170	National Grid, USA		Sep-07	Southwest Rhode Island Reliability Enhancements	Extend L-190 line to W. Kingston.	Planned	Planned	No ROW required	No new or expanded ROW required	Nov-04	Mar-05	RBU	$5,541,000	$5,541,000
1a	168	National Grid, USA		Nov-07	Southwest Rhode Island Reliability Enhancements	Reconductor Kenyon - Wood River 115 kV 1870 line.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-05	Mar-05	RBU	$1,597,000	**$1,731,997**
1a	173	National Grid, USA		Dec-07	Southwest Rhode Island Reliability Enhancements	Rebuild W. Kingston to include 115 kV ring bus.	Planned	Planned	No ROW required	No new or expanded ROW required	Nov-04	Mar-05	RBU	$2,930,000	**$2,850,000**
1a	171	National Grid, USA		Feb-08	Southwest Rhode Island Reliability Enhancements	Reconductoring L-190 between Kent Co. and Davisville.	Planned	Planned	No ROW required	No new or expanded ROW required	Nov-04	Mar-05	RBU	$1,458,000	**$1,592,000**
1a	547	National Grid, USA		Sep-06		Slayton Hill new 115 kV switch.	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	NR	No	RBU	$157,000	$157,000
1a	672	National Grid, USA		Aug-07		Lynn Substation - # 21 upgrade 115 kV breaker.	Planned	Planned	No ROW required	No new or expanded ROW required	NR	NR	RBU	$218,000	**$210,000**
1a	166	National Grid, USA		Mar-08		Replace 115 kV breakers at Tewksbury 22.	Planned	Planned	No ROW required	No new or expanded ROW required	NR	No	RBU	$3,192,000	**$3,092,000**
1a	167	National Grid, USA		Apr-08		New W. Amesbury 345 kV substation tapped off of (394) line between Ward Hill and Seabrook - King St. relief.	Planned	Planned	No ROW required	No new or expanded ROW required	Nov-05	No	RBU	$26,850,000	$26,850,000
1a	710	National Grid, USA		Mar-09		New W. Amesbury 115/23 kV substation.	Planned	Planned	No ROW required	No new or expanded ROW required	Nov-05	No	RBU	$7,800,000	$7,800,000
1a	680	National Grid, USA		Dec-09		Rebuild Bellows Falls Substation and install 115 kV capacitor bank.	Planned	Planned	No ROW required	No new or expanded ROW required	May-06	No	RBU	$11,500,000	**$11,497,000**
1a	98 [4]	Northeast Utilities-CT		2007	Haddam / Middletown Reliability Project	Rebuild 115-kV Manchester - Hopewell 1767 line and associated terminals.	Planned	Planned	No ROW required	No new or expanded ROW required	Aug-03	Dec-03	02	$3,100,000	**$7,187,000**
1a	100	Northeast Utilities-CT		Dec-06	Killingly Project	Install new Killingly substation and a 345/115 kV autotransformer and associated 345-kV breaker.	Under Construction	Under Construction	Expand existing; own property	No new or expanded ROW required	Aug-04	No	02	$31,663,000	$31,663,000
1a	99	Northeast Utilities-CT		Dec-06	Killingly Project	Lake Road generation SPS modifications.	Proposed	Proposed	No ROW required	No new or expanded ROW required	**Sep-06**	No	RBU	Part of Killingly Project	Part of Killingly Project
1a	101	Northeast Utilities-CT		Dec-06	Killingly Project	Add 345-kV circuit breaker at Card Substation.	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Aug-04	No	02	Part of Killingly Project	Part of Killingly Project
1a	248	Northeast Utilities-CT		2008	Norwalk-Glenbrook Cable Project	Install two new 115-kV cables from Norwalk to Glenbrook (accommodate 345 kV class cable).	Planned	Planned	No ROW required	New ROW required	Aug-05	No	02	$120,000,000	**$183,230,000**
1a	243	Northeast Utilities-CT		2008	Norwalk-Glenbrook Cable Project	Expand and upgrade to BPS and remove SPS at Glenbrook 115 kV substation.	Planned	Planned	Expand existing; own property	No new or expanded ROW required	Aug-05	No	02	$5,000,000	$5,000,000
1a	569	Connecticut Department of Transportation	Northeast Utilities CT	2008	Norwalk-Glenbrook Cable Project	Replace two 115-kV circuit breakers at Cos Cob.	Planned	Planned	No ROW required	No new or expanded ROW required	Aug-05	No	02	$500,000	$500,000
1a	570	Northeast Utilities-CT		2008	Norwalk-Glenbrook Cable Project	Add second high speed relay system on the 1450 line.	Planned	Planned	No ROW required	No new or expanded ROW required	Aug-05	No	02	$710,000	$710,000
1a	571	Northeast Utilities-CT		2008	Norwalk-Glenbrook Cable Project	Upgrade Flax Hill Substation to BPS.	Planned	Planned	No ROW required	No new or expanded ROW required	Aug-05	No	02	$2,000,000	$2,000,000
1a	87 [5]	Northeast Utilities-CT		2006	Southwest Connecticut (Bethel-Norwalk) Reliability Project	Build new 345-kV OH/UG line from Plumtree Substation to Norwalk Substation; includes (2) shunt reactors at Norwalk Jct. transition point.	Under Construction	Under Construction	No ROW required	Expansion of existing ROW required	Feb-04	**Sep-06**	02	$357,000,000	$357,000,000
1a	89 [5]	Northeast Utilities-CT		2006	Southwest Connecticut (Bethel-Norwalk) Reliability Project	Installation of new Norwalk 345-kV substation at Norwalk Substation; includes (4) 345-kV circuit breakers and (1) autotransformer.	Under Construction	Under Construction	New Station; own property	No new or expanded ROW required	Feb-04	**Sep-06**	02	Part of SWCT (Bethel-Norwalk) Reliability Project	Part of SWCT (Bethel-Norwalk) Reliability Project

Notes

[4] Project ID 98 (Haddam/Middletown Reliability Project): Northeast Utilities will submit a revised TCA application.

Notes
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Part#	Project ID	Primary Equipment Owner	Other Equipment Owner(s)	Projected In-Service Month/Year	Major Project	Project	July 2006 Status	October 2006 Status	Substation ROW	Transmission ROW	I.3.9 Approval	TCA Approval	TCA Category	July 2006 Estimated Costs	October 2006 Estimated Costs
	[5] Ancillary work for the Southwest Connecticut (Bethel-Norwalk) Reliability Project has been placed in-service and accounts for an estimated $63.3M of the total cost ($357M) of the project. The total cost estimate of $357M includes $117.4M of localized costs as determined in the ISO New England Draft Determination Letter issued September 22, 2006.														
1a	222 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Install new 345-kV line from Scovill Rock to Chestnut Jct.	Planned	Planned	No ROW required	Expansion of existing ROW required	Jan-06	No	02	$1,047,000,000	$1,047,000,000
1a	223 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Install (2) new 345-kV lines from Black Pond Jct. to Beseck Jct.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	224 [6]	United Illuminating Company	Northeast Utilities CT	2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Install new 345-kV line from East Devon to Singer(UI).	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	$110,000,000	$110,000,000
1a	225 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Install new 345-kV line from Oxbow Jct. to Beseck Jct.	Planned	Planned	No ROW required	New ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	226 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Install two 345-kV underground cables from Singer(UI) to Norwalk.	Planned	**Under Construction**	No ROW required	No new or expanded ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	227 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Install new 345-kV line from Beseck Jct. to East Devon.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	228 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Installation of new Beseck Jct. 345-kV switching station in Wallingford	Under Construction	Under Construction	New Station; own property	No new or expanded ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	229 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Install new East Devon 345-kV substation and new East Devon 115-kV substation in Milford.	Planned	Planned	New Station; purchase required	No new or expanded ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	230 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Expand 345-kV Scovill Rock Substation.	Planned	**Under Construction**	Expand existing; own property	No new or expanded ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	231 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Rebuild 115-kV Devon to Devon Switching Station(UI) 1780 and 1790 lines.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	232 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Build two 115-kV cables between East Devon and Devon.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	235 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Expand Norwalk 345-kV substation and install transfer trip relaying scheme on the 1389 115 kV line between Norwalk and Flax Hill.	Planned	**Under Construction**	Expand existing; own property	No new or expanded ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	236 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Rebuild 115-kV lines (1640,1685,1610) between Devon and Cook Hill Jct. (UG section of 1640 near Cook Hill)	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	237 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Rebuild 115-kV lines-1975 from Beseck to Oxbow Junction and 1655 from East Wallingford Jct. to New Haven Jct.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	238	United Illuminating Company		Dec-09	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Build new Singer 345 kV substation with (16) circuit breakers, (2) autos, (4) shunt reactors along with reconnecting Bridgeport Energy thru one of the new autos. Includes 115 kV connection from Singer to Pequonnock substation.	Planned	Planned	New Station; own property	No new or expanded ROW required	Jan-06	No	02	$122,000,000	$122,000,000
1a	242	United Illuminating Company		Dec-09	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Installation of 115-kV breakers at Elmwest Substation.	Planned	Planned	Expand existing; own property	No new or expanded ROW required	Jan-06	No	02	$5,000,000	$5,000,000
	Note														
	[6] These projects contain costs associated with Northeast Utilities portion of the Southwest Connecticut Middletown-Norwalk cost estimate of $1,047,000,000.														

Notes
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Part#	Project ID	Primary Equipment Owner	Other Equipment Owner(s)	Projected In-Service Month/Year	Major Project	Project	July 2006 Status	October 2006 Status	Substation ROW	Transmission ROW	I.3.9 Approval	TCA Approval	TCA Category	July 2006 Estimated Costs	October 2006 Estimated Costs
1a	245 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Disconnect Milford Power from Devon Substation and reconnect to East Devon Jct. Substation.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	246 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Add second 345/115-kV autotransformer at Norwalk Substation along with shunt reactors and 345-kV circuit breakers.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	551 [7]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Rebuild the 1466 115-kV line from East Meriden to North Wallingford.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	TBD	$605,000
1a	239 [7]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Install (1) new 115-kV circuit breaker at Devon Substation in series with 7R-2T.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	TBD	$5,059,000
1a	247 [7]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Replace Norwalk Harbor 138/115-kV autotransformer.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	TBD	$8,351,000
1a	611 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Remove a portion of the 115 kV 1690 line from Devon to Cook Hill Jct.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	683 [6]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Modify the Cross Sound Cable (CSC) 387 Line-End-Open Special Protection System (SPS).	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	TBD	Part of SWCT (Middletown-Norwalk) Reliability Project
1a	684 [7]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Replace (6) 115 kV breakers (4-Glenbrook, 1-Glenbrook Statcom, 1-Southington #1) and (2) 345 kV circuit breakers at Millstone.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	TBD	$5,134,000
1a	705 [7]	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Upgrade the Devon Substation ring buses #1 and #2.	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	TBD	TBD
1a	608	United Illuminating Company		Dec-09	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Upgrade Water Street, Broadway, Mill River, West River, Elmwest, Baird, Bridgeport RESCO, and Ash Creek substations to BPS standards.	Planned	Planned	TBD	TBD	Jan-06	No	02	$18,000,000	$18,000,000
1a	606	Northeast Utilities-CT		Sep-06		Upgrade Southington and Haddam Neck terminals of the 362 345 kV line.	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Dec-05	Dec-05	RBU	$1,890,000	$1,890,000
1a	207	Northeast Utilities-CT		Oct-06		Uprate Cos Cob - Tomac - South End 1750 line and reconductor five spans.	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Sep-05	No	RBU	$682,000	$682,000
1a	577	Northeast Utilities-CT		May-07		Add 115-kV circuit breaker at South End in series with 1G-6T.	Planned	Under Construction	No ROW required	No new or expanded ROW required	Feb-06	Jul-06	RBU	$800,000	$800,000
1a	104	Northeast Utilities-CT		2008		Replace 138-kV Norwalk(CT)-Northport(NY) 1385 cable.	Planned	Under Construction	No ROW required	No new or expanded ROW required	Dec-02	No	02	$71,700,000	$71,700,000
1a	202	Northeast Utilities-CT		2008		Install new 345/115-kV autotransformer at Barbour Hill Substation.	Proposed	Planned	No ROW required	No new or expanded ROW required	Sep-06	No	02	$37,000,000	$47,000,000
1a	85	Northeast Utilities-CT		TBD		Upgrade the South Meadow Substation to bulk power system standards (BPS).	Planned	Planned	No ROW required	No new or expanded ROW required	Aug-04	No	RBU	TBD	TBD
1a	103	Northeast Utilities-CT		TBD		Upgrade the East Hartford Substation to bulk power system standards (BPS).	Planned	Planned	No ROW required	No new or expanded ROW required	Aug-04	No	RBU	TBD	TBD
1a	102	Northeast Utilities-CT		TBD		Upgrade the Northwest Hartford Substation to bulk power system standards (BPS).	Planned	Planned	No ROW required	No new or expanded ROW required	Aug-04	No	RBU	TBD	TBD
1a	105	Northeast Utilities-CT		TBD		Upgrade the Berlin Substation to bulk power system standards (BPS).	Planned	Planned	No ROW required	No new or expanded ROW required	Aug-04	No	RBU	TBD	TBD
1a	106	Northeast Utilities-CT		TBD		Upgrade the Southwest Hartford Substation to bulk power system standards (BPS).	Planned	Planned	No ROW required	No new or expanded ROW required	Aug-04	No	RBU	TBD	TBD
1a	108	Northeast Utilities-MA		TBD		Upgrade the East Springfield Substation to bulk power system standards (BPS).	Planned	Planned	No ROW required	No new or expanded ROW required	Aug-04	No	RBU	TBD	TBD

Note

[7] Project IDs #239, 247, 551, 684, and 705 (Southwest Connecticut Reliability Project) : Costs for these projects not included in Northeast Utilities Middletown-Norwalk estimate of $1,047,000,000.

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Part#	Project ID	Primary Equipment Owner	Other Equipment Owner(s)	Projected In-Service Month/Year	Major Project	Project	July 2006 Status	October 2006 Status	Substation ROW	Transmission ROW	I.3.9 Approval	TCA Approval	TCA Category	July 2006 Estimated Costs	October 2006 Estimated Costs
1a	109	Northeast Utilities-MA		TBD		Upgrade the South Agawam Substation to bulk power system standards (BPS).	Planned	Planned	No ROW required	No new or expanded ROW required	Aug-04	No	RBU	TBD	TBD
1a	280	Northeast Utilities-NH		2008	Scobie Pond to Hudson Reinforcement Project	Rebuild 115-kV Scobie - Hudson X116 line.	Proposed	**Planned**	No ROW required	No new or expanded ROW required	**Jul-06**	No	RBU	$31,500,000	$31,500,000
1a	580	Northeast Utilities-NH		2007	Scobie Pond to Hudson Reinforcement Project	Install new 115-kV Scobie - Hudson line.	Proposed	**Planned**	No ROW required	No new or expanded ROW required	**Jul-06**	No	RBU	Part of Scobie-Hudson Reinforcement Project	Part of Scobie-Hudson Reinforcement Project
1a	581	Northeast Utilities-NH		2007	Scobie Pond to Hudson Reinforcement Project	Rebuild Hudson Substation to breaker and half.	Proposed	**Planned**	No ROW required	No new or expanded ROW required	**Jul-06**	No	RBU	Part of Scobie-Hudson Reinforcement Project	Part of Scobie-Hudson Reinforcement Project
1a	279	Northeast Utilities-NH		2007	Timber Swamp Project	Add 2nd 345/34.5-kV transformer at Timber Swamp Substation and ring bus.	Proposed	**Planned**	No ROW required	No new or expanded ROW required	**Sep-06**	No	RBU	$9,753,000	$9,753,000
1a	267	Northeast Utilities-NH	Central Maine Power Company	2008		White Lake - Saco Valley (Y138) Line Closing - Add PAR on Y138 at Saco Valley, retension lines, upgrade Beebe terminal, and add capacitors and breakers at Saco Valley. Also add capacitors at Kimball Rd. (CMP).	Planned	Planned	No ROW required	No new or expanded ROW required	Jan-06	No	02	$28,565,000	$28,565,000
1a	113	Northeast Utilities-NH		TBD		Upgrade the Garvins Substation to bulk power system standards (BPS).	Planned	Planned	No ROW required	No new or expanded ROW required	Aug-04	No	RBU	TBD	TBD
1a	274	Northeast Utilities-NH		TBD		Greggs 115 kV substation - Protection Separation Upgrade	Planned	Planned	No ROW required	No new or expanded ROW required	Oct-00	No	02	TBD	TBD
1a	302	NSTAR		**May-07**	Boston Area 115 kV Enhancements	DCT separation of Framingham to Speen St. 433-507 circuit	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Jan-05	Mar-05	02	$3,100,000	$3,100,000
1a	300	NSTAR		**May-07**	Boston Area 115 kV Enhancements	Upgrade 385-510/511 Kingston St. to Kingston Network 115 kV lines	Planned	Planned	No ROW required	No new or expanded ROW required	NR	No	02	$450,000	$450,000
1a	296	NSTAR		**Oct-06**	Nantucket Interconnection	Add one 10 MVAR Capacitor Bank at Orleans station.	Planned	Planned	No ROW required	No new or expanded ROW required	Mar-05	No	RBU	$1,200,000	$1,200,000
1a	114	NSTAR		**Dec-06**	NSTAR 345 kV Transmission Reliability Project	Add (1) new 345 kV UG Cables from Stoughton to Mattapan Sq.to K Street and install new autotransformer at K. St.	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	$225,600,000	$225,600,000
1a	115	NSTAR		**Dec-06**	NSTAR 345 kV Transmission Reliability Project	Add (1) 345/115 kV autotransformer at Hyde Park Substation	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
1a	117	NSTAR		**Dec-06**	NSTAR 345 kV Transmission Reliability Project	Add (1) new 345 kV UG Cable from Stoughton to Mattapan Sq. to Hyde Park Substation	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
1a	119	NSTAR		**Dec-06**	NSTAR 345 kV Transmission Reliability Project	Add (1) 345 kV breaker at Hyde Park Substation	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
1a	120	NSTAR		**Dec-06**	NSTAR 345 kV Transmission Reliability Project	Add (2) 115 kV circuit breakers at Hyde Park Substation	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
1a	121	NSTAR		**Dec-06**	NSTAR 345 kV Transmission Reliability Project	Add (3) 345 kV circuit breakers at K St.	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
1a	123	NSTAR		**Dec-06**	NSTAR 345 kV Transmission Reliability Project	Add (1) 345 kV 160 MVAR shunt reactors at K St.	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
1a	116	NSTAR		**Jun-08**	NSTAR 345 kV Transmission Reliability Project	Add 2nd 345 kV UG Cables from Stoughton to Mattapan Sq.to K Street and install another new autotransformer at K. St.	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
1a	122	NSTAR		**Jun-08**	NSTAR 345 kV Transmission Reliability Project	Add (5) 115 kV breakers at K St.	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
1a	126	NSTAR		**Jun-08**	NSTAR 345 kV Transmission Reliability Project	Install 2.75 Ohm series reactors on 115 kV circuits 385-510 and 385-511 at K St.	Planned	Planned	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project

Notes
- Gray shading indicates change from JULY '06 Update.
- All costs provided by Transmission Owners.

Part#	Project ID	Primary Equipment Owner	Other Equipment Owner(s)	Projected In-Service Month/Year	Major Project	Project	July 2006 Status	October 2006 Status	Substation ROW	Transmission ROW	I.3.9 Approval	TCA Approval	TCA Category	July 2006 Estimated Costs	October 2006 Estimated Costs
1a	127	NSTAR		Jun-08	NSTAR 345 kV Transmission Reliability Project	Relocate terminal position of 385-510 at K St.	Planned	Planned	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
1a	128	NSTAR		Jun-08	NSTAR 345 kV Transmission Reliability Project	Reconductor 115 kV circuits 329-512 and 329-513 between Kingston and Brighton.	Planned	Planned	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
1a	572	NSTAR		Jun-08	NSTAR 345 kV Transmission Reliability Project	Add (1) 345 kV 160 MVAR shunt reactors at Stoughton	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
1a	573	NSTAR		Jun-08	NSTAR 345 kV Transmission Reliability Project	Add (1) 345 kV 160 MVAR shunt reactors at K St.	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
1a	574	NSTAR		Jun-07		Add 4th 115/14 kV transformer and (2) 115 kV breakers at Colburn St.	Planned	Planned	No ROW required	No new or expanded ROW required	Dec-04	No	RBU	$1,000,000	$1,000,000
1a	135 [8]	Vermont Electric Power Co		Dec-06	Northwest Vermont Reliability Project	Blissville PAR	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Jan-03	Mar-03	02	$8,400,000	$8,400,000
1a	137 [8]	Vermont Electric Power Co		Dec-06	Northwest Vermont Reliability Project	New Haven-West Rutland 345kV line, 345/115 New Haven Sub with 115kV ring bus, and close the 345 kV ring bus at West Rutland	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Jan-03	Mar-03	02	$66,400,000	$66,400,000
1a	136 [8]	Vermont Electric Power Co		Oct-07	Northwest Vermont Reliability Project	Granite Sub Upgrade Phase 1: 230 kV PAR, 25 MVAR Cap. bank, +/- 75 MVAR STATCOM, and second 230/115 transformer	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Jan-03	Mar-03	02	$60,800,000	$60,800,000
1a	139 [8]	Vermont Electric Power Co		Oct-07	Northwest Vermont Reliability Project	Granite Sub Upgrade Phase 2: STATCOM expanded to +/ 150 MVAR and two 25 MVAR capacitor banks	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Jan-03	Mar-03	02	$11,000,000	$11,000,000
1a	134 [8]	Vermont Electric Power Co		Nov-07	Northwest Vermont Reliability Project	Williston Ring Bus	Under Construction	Under Construction	No ROW required	No new or expanded ROW required	Jan-03	Mar-03	02	$4,300,000	$4,300,000
1a	138 [8]	Vermont Electric Power Co		Nov-07	Northwest Vermont Reliability Project	N. Haven - Vergennes - Q. City 115 kV Line	Under Construction	Under Construction	Expanding existing purchase required	Expansion of existing ROW required	Jan-03	Mar-03	02	$56,200,000	$56,200,000
1a	319	Vermont Electric Power Co		Dec-06		Replace Y25 115 / 69kV Bennington transformer - keep existing transformer as spare.	Planned	Planned	No ROW required	No new or expanded ROW required	Mar-05	No	02	$2,450,000	$2,450,000
1b	144	Bangor Hydro-Electric Company		Dec-10		BHE Northern (Chester) area reliability improvement	Concept	Concept	TBD	TBD	No	No	RBU	TBD	TBD
1b	152	Central Maine Power Company		TBD	CMP Autotransformer	CMP Autotransformer Reliability Improvement	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	02	TBD	TBD
1b	151	Central Maine Power Company		Dec-08	Maine Voltage Enhancements	Add 170 MVArs of capacitors at Maxcys and Western Maine.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	02	$6,000,000	$6,000,000
1b	626	Central Maine Power Company		Dec-07	Rumford-Woodstock-Kimball Road Corridor Project	Addition of 115/34.5 kV transformer and new 115 kV breaker and a half substation at Woodstock.	Concept	Concept	TBD	TBD	No	No	RBU	TBD	TBD
1b	624	Central Maine Power Company		Dec-08	Rumford-Woodstock-Kimball Road Corridor Project	Install 115 kV line parallel to the Rumford-Industrial Park (Section 228) 115 kV line.	Concept	Concept	TBD	TBD	No	No	RBU	TBD	TBD
1b	625	Central Maine Power Company		Dec-08	Rumford-Woodstock-Kimball Road Corridor Project	Addition of Rumford Industrial Park capacitor bank.	Concept	Concept	TBD	TBD	No	No	RBU	TBD	TBD
1b	627	Central Maine Power Company		Dec-08	Rumford-Woodstock-Kimball Road Corridor Project	Reterminate (3) 115 kV lines and add (2) bus-tie breakers at Kimball Road.	Concept	Concept	TBD	TBD	No	No	RBU	TBD	TBD
1b	148	Central Maine Power Company		Dec-08		Establish a new Old Orchard Beach 115/34.5 kV substation and 115 kV line	Proposed	Proposed	New Station; own property	No new or expanded ROW required	No	No	02	$14,000,000	$14,000,000
1b	150	Central Maine Power Company		Dec-08		Add 115 kV line from Spring Street S/S to Sewall S/S	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	02	$5,900,000	$5,900,000

Note

[8] Project IDs #134-139 (Northwest Vermont Reliability Project) : VELCO developing amended TCA application expected early 2007.

Part#	Project ID	Primary Equipment Owner	Other Equipment Owner(s)	Projected In-Service Month/Year	Major Project	Project	July 2006 Status	October 2006 Status	Substation ROW	Transmission ROW	I.3.9 Approval	TCA Approval	TCA Category	July 2006 Estimated Costs	October 2006 Estimated Costs
1b	575	Central Maine Power Company		Dec-08		New Benton 115 kV switchyard.	Concept	Concept	New Station; own property	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	153	Central Maine Power Company		TBD		Western Maine Protection Improvements	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	164	National Grid, USA		Dec-09	A1/B2 Lines	Installation of Vernon, VT 69 kV capacitor bank and Pratts Jct. circuit breakers (2).	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$900,000	$900,000
1b	163	National Grid, USA		Mar-09	A1/B2 Lines	Convert E. Westminster sub to 115 kV (tap I-135S line)	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$2,517,000	$2,517,000
1b	188 [9]	National Grid, USA		TBD	NEMA/Boston-North/South Reliability Alternative	Install new Scobie - Tewksbury 345-kV line (NGRID portion).	Concept	Concept	TBD	TBD	No	No	02	$50,000,000	$50,000,000
1b	189 [9]	Northeast Utilities-NH		TBD	NEMA/Boston-North/South Reliability Alternative	Install new Scobie - Tewksbury 345-kV line (PSNH portion).	Concept	Concept	TBD	TBD	No	No	02	Part of NEMA/Boston-N/S Reliability Alternative	Part of NEMA/Boston-N/S Reliability Alternative
1b	161	National Grid, USA		Mar-09	North Shore Upgrades	Loop 345 kV 339 line and 115 kV S-145/T-146 into new Wakefield Jct. Substation w/ 345/115 kV autotransformer	Concept	Concept	New Station; own property	No new or expanded ROW required	No	No	02	$14,000,000	$14,000,000
1b	165	National Grid, USA		TBD	Rhode Island Additional Autotransformer	Install new 345/115 kV Autotransformer in SEMA/RI (e.g. Kent County, W.Farnum)	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	02	$3,000,000	$3,000,000
1b	190 [10]	National Grid, USA		TBD	Southern New England Transmission Reinforcement Projects	Rhode Island/Massachusetts Reinforcements.	Concept	Concept	TBD	TBD	No	No	02	TBD	TBD
1b	191 [10]	Northeast Utilities-CT		TBD	Southern New England Transmission Reinforcement Projects	Connecticut Interconnections	Concept	Concept	TBD	TBD	No	No	02	TBD	TBD
1b	576 [10]	Northeast Utilities-CT		TBD	Southern New England Transmission Reinforcement Projects	New 345-kV line from Eastern to Western Connecticut along with other transmission reinforcements.	Concept	Concept	TBD	TBD	No	No	02	TBD	TBD
1b	196 [10]	Northeast Utilities-MA		TBD	Southern New England Transmission Reinforcement Projects	New 345 and/or 115-kV Springfield reinforcements.	Concept	Concept	TBD	TBD	No	No	02	TBD	TBD
1b	673	National Grid, USA		Jan-09	Worcester Area Reinforcements	Bloomingdale Substation - #27 install 115 kV breaker.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$525,000	$525,000
1b	676	National Grid, USA		Apr-09	Worcester Area Reinforcements	New Bloomingdale to Vernon Hill 115 kV (UG Cable-3.6 mi.)	Proposed	Proposed	TBD	TBD	No	No	RBU	$6,800,000	$6,800,000
1b	484	National Grid, USA		Mar-07		Upgrade 115 kV circuit breakers at W. Farnum and add four new 115 kV breakers at Woonsocket.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	$3,000,000	$3,000,000
1b	544	National Grid, USA		Mar-07		New Farnum Pike Substation and taps.	Proposed	Proposed	New Station; own property	No new or expanded ROW required	No	No	RBU	$3,122,000	$3,122,000
1b	162	National Grid, USA		May-07		F-158N and Q-169 Golden Hills to Everett and to Lynn 115 kV line upgrades.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	02	$4,352,000	$4,335,000
1b	483	National Grid, USA		May-07		Upgrade bus work at Somerset.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$588,000	$585,000
1b	543	National Grid, USA		Oct-07		New Tower Hill Rd. Substation tapped off of (L190) 115 kV line.	Proposed	Proposed	New Station; own property	No new or expanded ROW required	No	No	RBU	$2,400,000	$2,400,000
1b	674	National Grid, USA		Mar-08		Replace Comerford 230 kV breakers.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$604,000	$604,000
1b	685	National Grid, USA		Mar-08		New 345 kV gas circuit breaker at Auburn St. Substation on the 335 Line.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$780,000	$780,000
1b	545	National Grid, USA		Mar-11		Tewksbury #22A GIS and protection/control replacements.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$16,700,000	$16,700,000

Notes

[9] Project IDs #188 and 189 (NEMA/Boston-North/South Reliability Alternative) : Cost is a preliminary estimate reported in RTEP03, which doesn't include Northeast Utilities cost estimate for their portion of the project.

[10] Project IDs #190, 191, 196, and 576 (Southern New England Transmission Reliability Project) : Cost estimates are currently being developed and will be dependent on the alternative selected as the proposed plan.

Notes
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Part#	Project ID	Primary Equipment Owner	Other Equipment Owner(s)	Projected In-Service Month/Year	Major Project	Project	July 2006 Status	October 2006 Status	Substation ROW	Transmission ROW	I.3.9 Approval	TCA Approval	TCA Category	July 2006 Estimated Costs	October 2006 Estimated Costs
1b	549	National Grid, USA		Mar-11		Pratts Junction 3rd 230/115 kV 150 MVA transformer.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$1,400,000	$1,400,000
1b	204	Northeast Utilities-CT		TBD	Northwest Connecticut Project	Falls Village Area conversion from 69-kV to 115-kV.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	02	TBD	TBD
1b	681	Northeast Utilities-CT		2009	Southwest Connecticut (Middletown-Norwalk) Reliability Project	Removal of the 348 and 362 345 kV line crossing.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	02	Part of SWCT (Middletown-Norwalk) Reliability Project	Part of SWCT (Middletown-Norwalk) Reliability Project
1b	218	Northeast Utilities-CT		TBD		Reconductor Tunnel-Ledyard Jct. & upgrade all 69-kV to 115-kV in Eastern CT.	Proposed	Concept	No ROW required	No new or expanded ROW required	No	No	02	TBD	TBD
1b	249	Northeast Utilities-CT		TBD		Install new 115-kV line from Norwalk Harbor Station to Glenbrook Substation (accommodate 345 kV class cable).	Proposed	Concept	No ROW required	No new or expanded ROW required	No	No	02	TBD	TBD
1b	212	Northeast Utilities-CT		TBD		Manchester/Barbour Hill Area Reinforcement	Proposed	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	210	Northeast Utilities-CT		TBD		Unbundle Oxbow Jct. to Beseck Jct. 115-kV	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	213	Northeast Utilities-CT		TBD		Install new 115-kV Frost Bridge - Walnut Hill Jct. line.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	02	TBD	TBD
1b	214	Northeast Utilities-CT		TBD		Rebuild 115-kV Frost Bridge - Campville 1191 line.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	216	Northeast Utilities-CT		TBD		Unbundle Colony to North Wallingford 115 kV	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	217	Northeast Utilities-CT		TBD		New supply to Mystic, CT area	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	215	Northeast Utilities-CT		TBD		Rebuild/Unbundle 115-kV Schwab Jct. to Colony 1355 line.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	221	Northeast Utilities-CT		TBD		Install new Frost Bridge - Bunker Hill 115-kV line.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	219	Northeast Utilities-CT		TBD		Rebuild 115-kV Card to Wawecus Jct. 1080 line.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	02	TBD	TBD
1b	220	Northeast Utilities-CT		TBD		Manchester - North Bloomfield 395 line reconfiguration	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	492	Northeast Utilities-CT		TBD		Add a 345-kV breaker at North Bloomfield.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	553	Northeast Utilities-CT		TBD		Add C-filters on 115-kV busses at Stony Hill and Rocky River Substations.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	554	Northeast Utilities-CT		TBD		Frost Bridge corridor 115-kV line reconfiguration.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$4,350,000	**$7,100,000**
1b	582	Northeast Utilities-CT		TBD		Separate 310 and 368 345-KV transmission lines.	Concept	Concept	TBD	TBD	No	No	RBU	TBD	TBD
1b	615	Northeast Utilities-CT		TBD		Build two 115-kV lines from Lake Road to Killingly.	Concept	Concept	Expand existing; own property	New ROW required	No	No	RBU	TBD	TBD
1b	628	Northeast Utilities-CT		TBD		Add a second 345/115-kV autotransformer at Haddam Substation.	Concept	Concept	Expand existing; own property	New ROW required	No	No	RBU	TBD	TBD
1b	490	Northeast Utilities-CT		TBD		Separate the 115-kV line from Windsor Locks to Enfield (1300 line).	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	**745**	**Northeast Utilities-CT**		**TBD**		**Ridgefield Area 115-kV Reinforcement**		**Concept**	**No ROW required**	**TBD**	**No**	**No**	**RBU**		**TBD**
1b	**746**	**Northeast Utilities-CT**		**TBD**		**Hanover 115-kV Reinforcement**		**Concept**	**No ROW required**	**TBD**	**No**	**No**	**RBU**		**TBD**
1b	**747**	**Northeast Utilities-CT**		**TBD**		**Greenwich - Stamford 115-kV Reinforcement**		**Concept**	**No ROW required**	**TBD**	**No**	**No**	**RBU**		**TBD**

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Part#	Project ID	Primary Equipment Owner	Other Equipment Owner(s)	Projected In-Service Month/Year	Major Project	Project	July 2006 Status	October 2006 Status	Substation ROW	Transmission ROW	I.3.9 Approval	TCA Approval	TCA Category	July 2006 Estimated Costs	October 2006 Estimated Costs
1b	748	Northeast Utilities-CT		TBD		Western Connecticut Reinforcement		Concept	TBD	TBD	No	No	RBU		TBD
1b	749	Northeast Utilities-CT		TBD		Southwest Area Reinforcement		Concept	TBD	TBD	No	No	RBU		TBD
1b	750	Northeast Utilities-CT		TBD		Northwest Area Reinforcement		Concept	TBD	TBD	No	No	RBU		TBD
1b	751	Northeast Utilities-CT		TBD		Middletown Area Reinforcement		Concept	TBD	TBD	No	No	RBU		TBD
1b	752	Northeast Utilities-CT		TBD		Greater Hartford Area Reinforcement		Concept	TBD	TBD	No	No	RBU		TBD
1b	753	Northeast Utilities-CT		TBD		Eastern Area Reinforcement		Concept	TBD	TBD	No	No	RBU		TBD
1b	754	Northeast Utilities-CT		TBD		Norwalk/Stamford Area Reinforcement		Concept	TBD	TBD	No	No	RBU		TBD
1b	686	Northeast Utilities-MA		2010	Springfield Area Reliability Upgrades	Installation of a new 115-kV cable circuit between East Springfield and Clinton Substations.	Concept	Concept	TBD	TBD	No	No	02	TBD	TBD
1b	687	Northeast Utilities-MA		2010	Springfield Area Reliability Upgrades	Upgrades and modifications at the 115-kV Fairmont Substation.	Concept	Concept	TBD	TBD	No	No	02	TBD	TBD
1b	688	Northeast Utilities-MA		2010	Springfield Area Reliability Upgrades	Modifications to the 1254 and 1723 115-kV lines.	Concept	Concept	TBD	TBD	No	No	02	TBD	TBD
1b	258	Northeast Utilities-MA		2010	Springfield Area Reliability Upgrades	Replace Breckwood to East Springfield 115-kV cable.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	02	TBD	TBD
1b	259	Northeast Utilities-MA		2010	Springfield Area Reliability Upgrades	Rebuild Shawinigan to Ludlow 115-kV line.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	02	TBD	TBD
1b	496	Northeast Utilities-MA		2010	Springfield Area Reliability Upgrades	Additional uprating or rebuilding of the existing 115-kV overhead lines in the Springfield area.	Concept	Concept	TBD	TBD	No	No	RBU	TBD	TBD
1b	250	Northeast Utilities-MA		TBD	Springfield Area Reliability Upgrades	Add a 345-kV breaker at Ludlow Substation.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	493	Northeast Utilities-MA		2008		Additional 345/115 kV transformation in the Berkshire/Pittsfield area.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	498	Northeast Utilities-MA		TBD		Install 115-kV capacitors at Montague Substation.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	760	Northeast Utilities-MA		TBD		Pittsfield/Greenfield Area Reinforcement		Concept	TBD	TBD	No	No	RBU		TBD
1b	277	Northeast Utilities-NH		TBD	New Hampshire Seacoast Area Reliability Project	Add a 345/115-kV 400 MVA autotransformer at Deerfield.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	02	$20,000,000	$20,000,000
1b	616	Northeast Utilities-NH		TBD	New Hampshire Seacoast Area Reliability Project	Add two 345/115-kV 400 MVA autotransformers and new substation and associated breakers at Gosling Road.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	02	$30,000,000	$30,000,000
1b	689	Northeast Utilities-NH		TBD	New Hampshire Seacoast Area Reliability Project	Rebuild Scobie - Chester (H141) 115-kV line	Proposed	Proposed	No ROW required	TBD	No	No	RBU	TBD	TBD
1b	26	Northeast Utilities-NH		TBD	New Hampshire Seacoast Area Reliability Project	Rebuild Schiller to Ocean Rd (U181&E194) 115-kV lines.	Proposed	Proposed	No ROW required	TBD	No	No	RBU	TBD	TBD
1b	268 [11]	Northeast Utilities-NH		TBD	Northern New England Transfer Capability	Reterminate 345-kV 391 line at Deerfield.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	02	$4,000,000	$4,000,000
1b	269 [11]	Northeast Utilities-NH		TBD	Northern New England Transfer Capability	Add SVC or capacitors at Deerfield.	Proposed	Proposed	TBD	No new or expanded ROW required	No	No	02	$25,000,000	$25,000,000
1b	579	Central Maine Power Company		Dec-08	Northern New England Transfer Capability	Addition of (3) 345 kV breakers at Buxton.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	02	$5,000,000	$5,000,000
1b	275	Northeast Utilities-NH		TBD		Merrimack 115-kV substation - Protection Separation Upgrade	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	02	TBD	TBD
1b	285	Northeast Utilities-NH		TBD		Install new 345-kV Seabrook Substation	Concept	Concept	New Station; own property	No new or expanded ROW required	No	No	RBU	TBD	TBD

Note

[11] Project IDs #268 and 269 (Northern New England Transfer Capability) : Reported cost is a conceptual estimate.

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1b	558	Northeast Utilities-NH		TBD		Rebuild 115-kV Greggs - Reeds Ferry B143 line.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	586	Northeast Utilities-NH		TBD		Central area capacitor additions.	Concept	Concept	TBD	TBD	No	No	RBU	TBD	TBD
1b	587	Northeast Utilities-NH		TBD		Install third 345/115-kV autotransformer at Scobie Substation.	Proposed	Proposed	TBD	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	487	Northeast Utilities-NH		TBD		Install new 115-kV line from Jackman to Peterborough.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	486	Northeast Utilities-NH		TBD		Install new 115-kV line from Long Hill to South Milford.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	690	Northeast Utilities-NH		TBD		Install new Dover - Rochester 115-kV line.	Concept	Concept	No ROW required	TBD	No	No	RBU	TBD	TBD
1b	691	Northeast Utilities-NH		TBD		Install new White Lake - Ashland 115-kV line.	Concept	Concept	No ROW required	TBD	No	No	RBU	TBD	TBD
1b	692	Northeast Utilities-NH		TBD		Install new Beebe - Pemigewasset 115-kV line.	Concept	Concept	No ROW required	TBD	No	No	RBU	TBD	TBD
1b	693	Northeast Utilities-NH		TBD		Install new Webster - Pemigewasset 115-kV line.	Concept	Concept	No ROW required	TBD	No	No	RBU	TBD	TBD
1b	**755**	**Northeast Utilities-NH**		**TBD**		**Berlin (Northern Area) Reinforcement**		**Concept**	**TBD**	**TBD**	**No**	**No**	**RBU**		**TBD**
1b	**756**	**Northeast Utilities-NH**		**TBD**		**Lakes Region (Central Area) Reinforcement**		**Concept**	**TBD**	**TBD**	**No**	**No**	**RBU**		**TBD**
1b	**757**	**Northeast Utilities-NH**		**TBD**		**Keene (Western Area) Reinforcement**		**Concept**	**TBD**	**TBD**	**No**	**No**	**RBU**		**TBD**
1b	**758**	**Northeast Utilities-NH**		**TBD**		**Manchester/Nashua (Southern Area) Reinforcement**		**Concept**	**TBD**	**TBD**	**No**	**No**	**RBU**		**TBD**
1b	**759**	**Northeast Utilities-NH**		**TBD**		**Portsmouth (Seacoast Area) Reinforcement**		**Concept**	**TBD**	**TBD**	**No**	**No**	**RBU**		**TBD**
1b	304	NSTAR		Jun-08	Boston Area 115 kV Enhancements	Add 115 kV 54 MVAR capacitor bank at Hartwell.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	02	$1,200,000	$1,200,000
1b	305	NSTAR		Jun-08	Boston Area 115 kV Enhancements	Add 115 kV 54 MVAR capacitor bank at East Cambridge.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	02	$2,500,000	$2,500,000
1b	301	NSTAR		Jun-09	Boston Area 115 kV Enhancements	Reconductor 115 kV circuits 320-507 and 320-508	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	02	$4,600,000	$4,600,000
1b	588	NSTAR		Oct-06		Upgrade Canal 115 kV breaker #12612 to 3000A.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$150,000	$150,000
1b	499	NSTAR		Nov-06		Install Tremont 115 kV bus tie circuit breakers.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$640,000	$640,000
1b	500	NSTAR		Jun-07		Install new 115 kV circuit breaker at Sandwich.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$500,000	$500,000
1b	501	NSTAR		Jun-07		Install new 115 kV circuit breaker at Hatchville.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$600,000	$600,000
1b	**761**	**NSTAR**		**Jun-07**		**Add 115 kV 32.9 MVAr capacitor bank at Mashpee.**		**Proposed**	**No ROW required**	**No new or expanded ROW required**	**No**	**No**	**RBU**		**$1,000,000**
1b	**713**	**NSTAR**		**Jun-07**		**Add 115 kV 18.8 MVAr capacitor bank at Harwich/Harwich Tap.**		**Proposed**	**No ROW required**	**No new or expanded ROW required**	**No**	**No**	**RBU**		**$900,000**
1b	**714**	**NSTAR**		**Jun-07**		**Add 115 kV 49.47 MVAr capacitor bank at Industrial Park.**		**Proposed**	**No ROW required**	**No new or expanded ROW required**	**No**	**No**	**RBU**		**$1,100,000**
1b	293	NSTAR		2007		Upgrade Canal 345 kV breaker #612 to IPT	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	02	$450,000	$450,000
1b	695	NSTAR		Mar-08		Loop (355) 345 kV line in and out of Carver Substation.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD

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1b	694	NSTAR		Apr-08		Add new 115 kV line from Brook Street to Auburn Street.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	$5,500,000	$5,500,000
1b	679	NSTAR		Jun-08		Upgrade Walpole 115 kV substation by replacing (2) 115 kV breakers.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$2,000,000	$2,000,000
1b	591	NSTAR		2008		Upgrade (19) 115 kV breakers at Mystic to IPT.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$3,500,000	$3,500,000
1b	718	NSTAR		2008		Add (2) 115 kV 35 MVAr shunt reactors at Bourne.		Proposed	No ROW required	No new or expanded ROW required	No	No	RBU		$1,900,000
1b	719	NSTAR		2008		Add (2) 115 kV 40 MVAr shunt reactors at Edgar Station.		Proposed	No ROW required	No new or expanded ROW required	No	No	RBU		$2,000,000
1b	592	NSTAR		2009		Cape Cod Canal Crossing Improvement Project	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	$5,000,000	$5,000,000
1b	593	NSTAR		2009		Add new 115 kV line from West Pond to Manomet.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	696	NSTAR		2009		Establish a new 115/13.8 kV substation in Medway/Norfolk area.	Concept	Concept	TBD	No new or expanded ROW required	No	No	RBU	$4,000,000	$4,000,000
1b	697	NSTAR		2009		New Natick 115/13.8 kV substation.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	$4,000,000	$4,000,000
1b	720	NSTAR		2009		Install new 115 kV substation in Burlington area.		Proposed	No ROW required	No new or expanded ROW required	No	No	RBU		$3,000,000
1b	503	NSTAR		2010		Add a new 115 kV underground circuit from Kendall to Somerville.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	589	NSTAR		2010		Upgrade W. Framingham 115kV station to ring bus.	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	309	NSTAR		2012		Add second Mystic to Chelsea 115 kV circuit	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
1b	698	United Illuminating Company		Dec-07		Replace (2) Grand Avenue 115 kV Oil Circuit Breakers.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	RBU	$800,000	$800,000
1b	313	United Illuminating Company		Dec-07		New Trumbull 115/13.8 kV Substation	Proposed	Proposed	New Station; own property	No new or expanded ROW required	No	No	02	$3,000,000	$3,000,000
1b	312	United Illuminating Company		Dec-07		Establish 115 kV supply to Metro North - Union Avenue, New Haven 115/27.6 kV substation.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	02	$3,800,000	$3,800,000
1b	699	United Illuminating Company		Jun-11		Naugatuck Valley 115 kV voltage improvement.	Concept	Concept	Expanding existing purchase required	No new or expanded ROW required	No	No	RBU	$11,000,000	$25,000,000
1b	721	United Illuminating Company		Dec-11		New Shelton 115 kV switching station.		Concept	New Station; purchase required	No new or expanded ROW required	No	No	RBU		$4,000,000
1b	316	United Illuminating Company		Dec-13		New Southport 115/13.8 kV substation	Concept	Concept	New Station; purchase required	No new or expanded ROW required	No	No	02	$2,000,000	$2,000,000
1b	317	United Illuminating Company		Dec-15		New North Branford 115/13.8 kV substation.	Concept	Concept	New Station; purchase required	No new or expanded ROW required	No	No	RBU	$2,000,000	$2,000,000
1b	320	Vermont Electric Power Co		Dec-06		Middlesex Substation relocation and breaker addition	Proposed	Proposed	Expanding existing purchase required	No new or expanded ROW required	No	No	02	$2,000,000	$2,000,000
1b	322	Vermont Electric Power Co		Dec-07		Lamoille County Upgrade Project	Proposed	Proposed	New Station; purchase required	No new or expanded ROW required	No	No	RBU	$1,500,000	$1,500,000
1b	325	Vermont Electric Power Co		Dec-08		Chelsea 115kV Breakers - Replace (2) SCADA controlled motorized disconnect switches with 115kV circuit breakers at the existing Chelsea substation	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	No	02	$3,000,000	$3,000,000
1b	321	Vermont Electric Power Co		Dec-08		Burlington 115kV Loop - 5.7 mi of new line between two existing substations	Concept	Concept	Expanding existing purchase required	Expansion of existing ROW required	No	No	02	$10,000,000	$10,000,000

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1b	318	Vermont Electric Power Co		Dec-09		Georgia 115kV Substation Ring Bus - Rebuild the existing Georgia substation 115kV bus into a ring bus	Concept	Concept	Expanding existing purchase required	No new or expanded ROW required	No	No	02	$7,000,000	$7,000,000
1b	323	Vermont Electric Power Co		Dec-10	Vermont Southern Loop Project	New Bennington to Manchester to Vernon Road 115 kV line or alternate equivalent.	Proposed	Proposed	New Station; purchase required	No new or expanded ROW required	No	No	02	$72,000,000	$72,000,000
1b	324	Vermont Electric Power Co		Dec-15		Granite to Middlesex 230 kV with necessary substation upgrades	Proposed	Proposed	Expanding existing purchase required	Expansion of existing ROW required	No	No	02	$60,000,000	$60,000,000
1b	326	TBD		TBD	East-West Oscillation Mitigation	East-West Oscillation Mitigation	Concept	Concept	TBD	TBD	No	No	02	TBD	TBD
GENERATOR INTERCONNECTION PROJECTS															
2a	327	Central Maine Power Company		Dec-07	Redington Wind Farm	Separate Section 215 from Section 63 and terminate Section 215 at newly established breaker position in Wyman Hydro S/S, which includes re-rating of Section 215. Expand Bigelow S/S and add capacitor banks at Lakewood, Guilford, and Sturtevant S/S's.	Proposed	Proposed	No ROW required	No new or expanded ROW required	Dec-03	NR	GI	NR	NR
2a	505	National Grid, USA		May-07	Hoosac Wind Farm	Tap Y-25S line between Harriman and Deerfield 5. Construct 69/34.5 kV substation and 34.5 kV line connecting 30 MW generating facility with the 69 kV system.	Proposed	Proposed	New Station; own property	No new or expanded ROW required	Feb-05	NR	GI	NR	NR
2a	594	National Grid, USA		Jun-07	Cape Wind	Upgrade the Auburn 345 kV breaker #2130 with an IPT breaker.	Proposed	Proposed	No ROW required	No new or expanded ROW required	Jul-05	NR	GI	NR	NR
2a	725	Northeast Utilities-CT		2006	South Norwalk Repowering	Norwalk 115 kV Substation		Proposed	No ROW required	No new or expanded ROW required	Oct-04	NR	GI	NR	NR
2a	331	Northeast Utilities-CT		TBD	Kleen Energy	Interconnection to CL&P's 345 kV line between Scovill Rock and Manchester	Proposed		No ROW required	No new or expanded ROW required	Sep-03	NR	GI	NR	NR
2a	722	Northeast Utilities-MA		TBD	Berkshire Wind Power Project	Interconnecting to WMECO at brodie Mt. in Lanesboro MA		Planned	No ROW required	No new or expanded ROW required	Aug-04	NR	GI	NR	NR
2a	595	NSTAR		TBD	Cape Wind	Expansion of Barnstable 115 kV substation to include 5th bay and (2) circuit breakers, addition of a 3rd breaker in the planned 4th bay, and (2) 35MVAr shunt reactors.	Proposed	Proposed	Expand existing; own property	No new or expanded ROW required	Jul-05	NR	GI	NR	NR
2a	596	NSTAR		TBD	Cape Wind	Installation of (2) 115 kV circuits out of Barnstable substation to interconnect Cape Wind.	Proposed	Proposed	No ROW required	No new or expanded ROW required	Jul-05	NR	GI	NR	NR
2a	597	NSTAR		TBD	Cape Wind	Upgrade the Brook St. 115 kV EW42 circuit breaker to 2000A.	Proposed	Proposed	No ROW required	No new or expanded ROW required	Jul-05	NR	GI	NR	NR
2a	598	NSTAR		TBD	Cape Wind	At Canal 345 kV substation, install a redundant breaker in series with breaker #312 and replace breakers #112 and #512 with IPT breakers.	Proposed	Proposed	No ROW required	No new or expanded ROW required	Jul-05	NR	GI	NR	NR
2a	599	NSTAR		TBD	Cape Wind	Upgrade the Bourne 115 kV breaker #12272 with an IPT breaker.	Proposed	Proposed	No ROW required	No new or expanded ROW required	Jul-05	NR	GI	NR	NR
2a	600	NSTAR		TBD	Cape Wind	Installation of differential insulation and additional grounding at each tower that is common for the 342 and 322 345 kV lines.	Proposed	Proposed	No ROW required	No new or expanded ROW required	Jul-05	NR	GI	NR	NR
2b	723	National Grid, USA		Dec-08	Gas Turbine	337 Sandy Pond - Tewksbury 345 kV Line		Concept	No ROW required	No new or expanded ROW required	No	NR	GI	NR	NR
2b	724	National Grid, USA		Nov-09	Hydro	NGRID Comerford Substation		Concept	No ROW required	No new or expanded ROW required	No	NR	GI	NR	NR
2b	726	CMEEC		Jan-07	Gas Turbine	Wallingford Electric Division, East Street Substation		Concept	No ROW required	No new or expanded ROW required	No	NR	GI	NR	NR
2b	621	Northeast Utilities-CT		Jan-07	AL Pierce	Interconnection to Wallingford (CMEEC) substation.	Concept	Concept	No ROW required	No new or expanded ROW required	No	NR	GI	NR	NR

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2b	618	Northeast Utilities-CT		Jun-07	Cos Cob	Interconnection to CL&P's Cos Cob substation.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	NR	GI	NR	NR
2b	619	Northeast Utilities-CT		Jul-07	Norwalk Harbor	Interconnection to CL&P's Norwalk Harbor substation.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	NR	GI	NR	NR
2b	620	Northeast Utilities-CT		Dec-07	Exeter Wind Project	Interconnection to CL&P's 115-kV 1607 line.	Concept	Concept	No ROW required	No new or expanded ROW required	No	NR	GI	NR	NR
2b	511	Northeast Utilities-CT		2008	Waterside	Interconnection to Waterside 115-kV substation.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	NR	GI	NR	NR
2b	622	Northeast Utilities-MA		Jun-09	Russell Biomass	Interconnection to WMECO's 115-kV 1512 line.	Proposed	Proposed	No ROW required	No new or expanded ROW required	No	NR	GI	NR	NR
2b	**727**	**Northeast Utilities-CT**		**Jan-07**	**Fuel Cell**	**CL&P P&WA Aircraft Substation**		**Concept**	**No ROW required**	**No new or expanded ROW required**	**No**	**NR**	**GI**	**NR**	**NR**
2b	**728**	**Northeast Utilities-CT**		**Jun-07**	**Cos Cob Redevelopment**	**Cos Cob 115 kV Substation**		**Concept**	**No ROW required**	**No new or expanded ROW required**	**No**	**NR**	**GI**	**NR**	**NR**
2b	**730**	**Northeast Utilities-CT**		**May-08**	**Gas Turbine**	**CL&P Middletown Substation**		**Concept**	**No ROW required**	**No new or expanded ROW required**	**No**	**NR**	**GI**	**NR**	**NR**
2b	**732**	**Northeast Utilities-CT**		**Dec-08**	**Fuel Cell**	**NU Triangle Substation**		**Concept**	**No ROW required**	**No new or expanded ROW required**	**No**	**NR**	**GI**	**NR**	**NR**
2b	**733**	**Northeast Utilities-CT**		**Dec-08**	**Biomass**	**CL&P Fry Brook Substation**		**Concept**	**No ROW required**	**No new or expanded ROW required**	**No**	**NR**	**GI**	**NR**	**NR**
2b	**734**	**Northeast Utilities-CT**		**Mar-09**	**Gas Turbine**	**Devon Substation**		**Concept**	**No ROW required**	**No new or expanded ROW required**	**No**	**NR**	**GI**	**NR**	**NR**
2b	**735**	**Northeast Utilities-CT**		**Jan-09**	**Gas Turbine**	**CL&P Middletown Substation**		**Concept**	**No ROW required**	**No new or expanded ROW required**	**No**	**NR**	**GI**	**NR**	**NR**
2b	**736**	**Northeast Utilities-CT**		**Jan-09**	**Gas Turbine**	**CL&P Middletown Substation or CL&P Scovill Rock Substation**		**Concept**	**No ROW required**	**No new or expanded ROW required**	**No**	**NR**	**GI**	**NR**	**NR**
2b	**737**	**Northeast Utilities-CT**		**Dec-12**	**Integrated Gasifier Combined Cycle**	**Montville Substation**		**Concept**	**No ROW required**	**No new or expanded ROW required**	**No**	**NR**	**GI**	**NR**	**NR**
2b	**729**	**United Illuminating Company**		**Jun-07**	**Gas Turbine**	**Pequonnock 115 kV Substation**		**Concept**	**No ROW required**	**No new or expanded ROW required**	**No**	**NR**	**GI**	**NR**	**NR**
2b	**731**	**United Illuminating Company**		**Dec-08**	**Fuel Cell**	**UI Congress Street**		**Concept**	**No ROW required**	**No new or expanded ROW required**	**No**	**NR**	**GI**	**NR**	**NR**
ECONOMIC PROJECTS															
3b	338	NSTAR		2008	Cape Cod Long Term	Move Canal 345/115 Auto-transformer to Oak Street	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
3b	337	NSTAR		2008	Cape Cod Long Term	Canal to Oak Street #399 345 kV Line	Concept	Concept	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	TBD
ELECTIVE PROJECTS															

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IN-SERVICE PROJECTS															
1a	69	National Grid, USA		Jun-06	Central Massachusetts Reinforcements	Reconductor O141N 115 kV Pratts/Millbury ROW to Greendale Sub	Under Construction	**In-Service**	No ROW required	No new or expanded ROW required	Apr-04	Apr-06	02	$605,000	$605,000
1a	678	National Grid, USA		Jun-06	Central Massachusetts Reinforcements	Rolfe Ave. upgrade 115 kV breaker	Under Construction	**In-Service**	No ROW required	No new or expanded ROW required	Apr-04	Apr-06	RBU	$220,000	$220,000
1a	157	National Grid, USA		Sep-05	North Shore Upgrades	Reconductor lines B154 and C155 from Ward Hill to King Street Tap.	In-Service	In-Service	No ROW required	No new or expanded ROW required	Jul-04	**Aug-06**	02	$4,500,000	$4,500,000
1a	630	National Grid, USA		Nov-05	North Shore Upgrades	East Methuen - replace 115 kV breaker.	In-service	In-service	No ROW required	No new or expanded ROW required	Oct-05	**Aug-06**	02	$442,000	$442,000
1a	540	National Grid, USA		Jun-06	North Shore Upgrades	Reconductor G-133E 115 kV line.	Under Construction	**In-Service**	No ROW required	No new or expanded ROW required	Jul-04	**Aug-06**	02	$1,673,000	$1,673,000
1a	158	National Grid, USA		Jul-06	North Shore Upgrades	Salem Harbor - (2) 115 kV 63 MVAR capacitor banks.	Under Construction	**In-Service**	No ROW required	No new or expanded ROW required	Oct-05	**Aug-06**	02	$3,228,000	$3,228,000
1a	159	National Grid, USA		Jul-06	North Shore Upgrades	Installation of Ward Hill breaker and a half bus, (3) additional autotransformers, and 115 kV breaker.	Under Construction	**In-Service**	Expand existing; own property	No new or expanded ROW required	Oct-05	**Aug-06**	02	$50,000,000	$50,000,000
1a	65	National Grid, USA		**May-06**		Brayton Point GIS and protection/control building.	Under Construction	**In-Service**	New Station; own property	No new or expanded ROW required	NR	May-03	02	$11,621,000	$11,621,000
1a	671	National Grid, USA		**May-06**		Install 115 kV air break switch on 0-167 line.	Planned	**In-Service**	No ROW required	No new or expanded ROW required	NR	NR	RBU	$199,000	**$134,000**
1a	95 [5]	Northeast Utilities-CT		2005	Southwest Connecticut (Bethel-Norwalk) Reliability Project	Replace (3) 115-kV circuit breakers at Norwalk Harbor Substation.	In-Service	In-Service	No ROW required	No new or expanded ROW required	Feb-04	**Sep-06**	02	$518,000	$518,000
1a	88 [5]	Northeast Utilities-CT		2006	Southwest Connecticut (Bethel-Norwalk) Reliability Project	Rebuild portions of 115-kV lines (1565,1470) from Plumtree Substation to Norwalk Substation	In-Service	In-Service	No ROW required	No new or expanded ROW required	Feb-04	**Sep-06**	02	$37,806,000	$37,806,000
1a	90 [5]	Northeast Utilities-CT		2006	Southwest Connecticut (Bethel-Norwalk) Reliability Project	Expand Plumtree 345-kV substation; includes (7) 345-kV circuit breakers and (1) shunt reactor.	In-Service	In-Service	Expand existing; own property	No new or expanded ROW required	Feb-04	**Sep-06**	02	$18,585,000	$18,585,000
1a	91 [5]	Northeast Utilities-CT		2006	Southwest Connecticut (Bethel-Norwalk) Reliability Project	Add two 115-kV 3% reactors on the 1910 and 1950 lines at Southington.	In-Service	In-Service	No ROW required	No new or expanded ROW required	Feb-04	**Sep-06**	02	$2,528,650	$2,528,650
1a	93 [5]	Northeast Utilities-CT		2006	Southwest Connecticut (Bethel-Norwalk) Reliability Project	Add 345-kV circuit breaker at Long Mountain Substation.	In-Service	In-Service	No ROW required	No new or expanded ROW required	Feb-04	**Sep-06**	02	$3,005,697	$3,005,697
1a	94 [5]	Northeast Utilities-CT		2006	Southwest Connecticut (Bethel-Norwalk) Reliability Project	Add Special Protection System (SPS) at Glenbrook Substation.	In-Service	In-Service	No ROW required	No new or expanded ROW required	Feb-04	**Sep-06**	02	$301,215	$301,215
1a	96 [5]	Northeast Utilities-CT		2006	Southwest Connecticut (Bethel-Norwalk) Reliability Project	Replace limiting terminal equipment at Southington and Millstone Substations.	In-Service	In-Service	No ROW required	No new or expanded ROW required	Feb-04	**Sep-06**	02	$535,694	$535,694
1a	251	Northeast Utilities-MA		Jul-06		Add 115-kV capacitor banks at Woodland/Pleasant Substations.	Under Construction	**In-Service**	No ROW required	No new or expanded ROW required	Jul-05	May-06	02	$4,575,000	**$4,675,000**
1a	617	Northeast Utilities-NH		Jun-06		Add a 345-kV breaker at Deerfield.	Under Construction	**In-Service**	No ROW required	No new or expanded ROW required	May-06	**Jun-06**	RBU	$1,700,000	**$1,435,000**
1a	303	NSTAR		Jun-06	Boston Area 115 kV Enhancements	Add 115 kV 54 MVAR capacitor bank at Sudbury.	Planned	**In-Service**	No ROW required	No new or expanded ROW required	Apr-06	No	02	$1,200,000	$1,200,000
1a	118	NSTAR		Jun-06	NSTAR 345 kV Transmission Reliability Project	Add (3) 345 kV 160 MVAR shunt reactors at Stoughton	Under Construction	**In-Service**	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
1a	124	NSTAR		Jun-06	NSTAR 345 kV Transmission Reliability Project	Add (2) Heat Exchangers on Baker-Hyde Park 115 kV circuits.	Under Construction	**In-Service**	No ROW required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
1a	125	NSTAR		Jun-06	NSTAR 345 kV Transmission Reliability Project	Add 345 kV Stoughton switching station in ring bus configuration along with circuit breakers.	Under Construction	**In-Service**	New Station; purchase required	No new or expanded ROW required	Feb-05	Sep-05	02	Part of NSTAR 345 kV Reliability Project	Part of NSTAR 345 kV Reliability Project
2a	**739**	**Northeast Utilities-CT**		**May-06**		**Millstone 3 Uprate**	**In-Service**	**In-Service**	**No ROW required**	**No new or expanded ROW required**	**Jul-05**	**NR**	**GI**	**NR**	**NR**

Notes
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- All costs provided by Transmission Owners.

Part#	Project ID	Primary Equipment Owner	Other Equipment Owner(s)	Projected In-Service Month/Year	Major Project	Project	July 2006 Status	October 2006 Status	Substation ROW	Transmission ROW	I.3.9 Approval	TCA Approval	TCA Category	July 2006 Estimated Costs	October 2006 Estimated Costs
CANCELLED PROJECTS															
1b	160	National Grid, USA		Mar-08	North Shore Upgrades	Golden Hills 345 kV ring bus	Concept	Cancelled	No ROW required	No new or expanded ROW required	No	No	02	$2,800,000	NR
1b	495	Northeast Utilities-MA		TBD	Springfield Area Reliability Upgrades	Install new 345-kV transmission circuits in the Springfield area.	Concept	Cancelled	TBD	TBD	No	No	RBU	TBD	NR
1b	578	Northeast Utilities-MA		TBD	Springfield Area Reliability Upgrades	Install new 115-kV transmission circuits in the Springfield area.	Concept	Cancelled	TBD	TBD	No	No	RBU	TBD	NR
1b	494	Northeast Utilities-MA		TBD	Springfield Area Reliability Upgrades	Add 345/115-kV transformation in the Springfield area.	Concept	Cancelled	TBD	TBD	No	No	RBU	TBD	NR
1b	497	Northeast Utilities-MA		TBD	Springfield Area Reliability Upgrades	Add capacitors in Springfield area substations for voltage support.	Concept	Cancelled	TBD	No new or expanded ROW required	No	No	RBU	TBD	NR
1b	614	Northeast Utilities-MA		TBD	Springfield Area Reliability Upgrades	Rebuild both Agawam to West Springfield 115 kV lines.	Concept	Cancelled	No ROW required	No new or expanded ROW required	No	No	RBU	TBD	NR
1b	307	NSTAR		2008		Re-conductor 115 kV Auburn St. - Kingston line #191	Proposed	Cancelled	No ROW required	No new or expanded ROW required	No	No	02	$3,900,000	NR
1b	308	NSTAR		2007		Upgrade 115 kV Brook Street to Kingston 117 line.	Proposed	Cancelled	No ROW required	No new or expanded ROW required	No	No	RBU	$3,200,000	NR

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